Appendix H:

KPMG's April 2010 Report and Appendices

Manitoba Hydro – External Quality Review

Main Report

April 15, 2010

ADVISORY

AUDIT • TAX • ADVISORY

Table of Contents

Executive Summary i

Scope of the Review i
Background ii
Key Highlights ii
Approach of the Review iii
Issues and Themes iv
Forecasting Models v
Issues vi
Operational Context vi
Forecasting Models – Key Findings viii
Power Sales Management xvi
Issues xvi
Operational Context xvi
Power Sales Management – Key Findings xxi
Risk Governance xxiv
Issues xxiv
Operational Context xxiv
Risk Governance – Key Findings xxv
Power Risk Management xxvii
Issues xxvii
Operational Context xxvii
Power Risk Management – Key Findings xxx
Conclusion xxxi

1. Introduction 1
1.1 Scope and Nature of the KPMG Review 1
1.1.1 Scope of the Review 1
1.1.2 Phasing of the Review 2
1.1.3 Reliance on MH Information...2
1.2 Conceptual Framework...3
1.2.1 Issues and Themes 3
1.2.2 Concept of Risk 5
1.3 Approach to Phase 2 of the Review 6
1.3.1 Multiple Lines of Evidence...6
1.3.2 Review of Consultant's Reports 7
1.3.3 Communications with the Consultant 7
1.3.4 Time Frame of the Assertions and Impact on This Review 8
1.3.5 Case Studies of Other Power Utilities 9
1.3.6 Use of Subconsultants...10
1.4 Organization of Phase 2 Report 11

2. Overview of Manitoba Hydro...13
2.1 Historical Overview and Legislative Mandate 13
2.2 Overview of Electricity Operations 14
2.3 Financial and Operational Overview 15
2.3.1 Background Information on MH's Capital Structure 16

3. Forecasting Models..21
3.1 Scope of Our Review 21
3.2 Key Findings...24
3.3 Approach to Our Review 29
3.3.1 Approach in Review of HERMES...30
3.3.2 Approach in our Review of SPLASH and PRISM 34
3.3.3 Other Approach Comments 34
3.4 Overview of Models 35
3.4.1 Description of Models 35
3.4.2 Operational Context for Models 39
3.5 Review of HERMES - Model Validity..44
3.6 Review of HERMES - Model Operations 48
3.6.1 Model Operation..48
3.6.2 Model Revision Process..49
3.6.3 Model Accountability and Model Use 50

3.6.4 Proposed Model Enhancements 52
3.6.5 Model Documentation 53
3.7 Review of HERMES – Model Assumptions and Data 53
3.7.1 Model Optimization Method 54
3.7.2 Antecedent Forecasting of Water Flow 57
3.7.3 Power Pricing Data Inputs 63
3.7.4 Market Developments 67
3.7.5 Potential Errors in Price Inputs 71
3.7.6 Data on Historical Flow Record 75
3.7.7 Lake Level Balances 81
3.7.8 Lake Level Balance Discrepancies 82
3.7.9 Production Coefficient Data 86
3.7.10 Storage Option Modeling Techniques 92
3.7.11 Drought Risk 94
3.8 Sensitivity Analysis – Impact of Price Inputs on HERMES 102
3.8.1 Initial Run Set and Optimal Run 102
3.8.2 Run Based on External Forecast (Forecast Run) 104
3.8.3 Alternative Run Set 106
3.8.4 Findings 108
3.9 Review of HERMES – Conclusions and Recommendations 109
3.9.1 Conclusion 109
3.9.2 Recommendations 110
3.10 Review of SPLASH 112
3.10.1 Model Overview 112
3.10.2 SPLASH Model Validity 112
3.10.3 SPLASH Model Operations 116
3.11 Review of PRISM 117
3.11.1 Model Overview 117
3.11.2 Assumptions and Data 117
3.12 Review of the Issue of Multiple Models 118
3.13 Conclusion 119

4. Power Sales Management 121
4.1 Scope of Our Review 121
4.2 Key Findings 123
4.3 Approach and Methodology 125
4.4 MH's Rationale for Exporting Power 125
4.5 Manitoba Hydro's Rationale for Long-term Contracts 131
4.5.1 Risk Mitigation 134

4.5.2 Securing Access to Firm Transmission 139
4.5.3 Lower Rates for Manitoba Ratepayers 145
4.6 Pricing of Power Sold under Long-term Contract 146
4.6.1 Long-Term Contract Pricing 150
4.6.2 Long-Term Electricity Price Forecast 152
4.6.3 Avoided Cost Analysis 154
4.6.4 Escalation Factors in Long-Term Contracts 155
4.7 Sales Volume Commitments 158
4.7.1 Assessment of MH's Dependable Energy methodology 159
4.8 Contract Structure 164
4.9 Manitoba Hydro's Risk Mitigation Strategies for Power Sales 165
4.9.1 Comments on the Embedded Call Option 166
4.9.2 Comments on Volume Curtailment Provisions 167
4.9.3 Impact of Diversity Agreements 168
4.10 Drought Risk Analysis of MH's Preferred Development Sequence 171
4.10.1 Assessment of Drought Risk on MH's Preferred Development Sequence 173
4.10.2 Low Flow Scenarios 175
4.10.3 High Flow Scenarios 177
4.10.4 Impact of Curtailment Rights 179
4.11 Quantification of Drought Risk and Associated Risk Capital Reserves 179
4.11.1 Summary Results 180
4.12 Conclusion 183

5. Risk Governance 185
5.1 Scope of Our Review 185
5.2 Key Findings 188
5.3 Approach and Methodology 189
5.4 Manitoba Hydro's Risk Governance Practices 191
5.4.1 Roles, Responsibilities and Reporting Relationships 193
5.4.2 Policies 203
5.5 Risk Governance Leading Practices 210
5.6 Case Studies 213
5.6.1 Overall Risk Governance Structure 214
5.7 Risk Management Roles, Responsibilities and Reporting Relationships 216
5.8 Risk Management Policies 218
5.9 Conclusion 220

6. Power Risk Management 221

6.1 Scope of Our Review 221
6.2 Key Findings 224
6.3 Approach and Methodologies 225
6.3.1 A Note on Leading Practices 225
6.4 Risk Identification 226
6.4.1 Long-Term Export Contracts – Risk Identification 227
6.5 Risk Measurement 233
6.5.1 Mark-to-Market 234
6.5.2 Risk Analytics 239
6.5.3 Credit Risk Management 247
6.6 Risk Control 252
6.6.1 Risk Limits 252
6.6.2 Transaction Processing Controls 260
6.7 Risk Reporting 268
6.7.1 Adequacy of Risk Reporting 269
6.8 Conclusion 274

7. Conclusions and Recommendations 275

7.1 Conclusions 275
7.2 Recommendations 277
7.3 Key Highlights 281

Appendix A	Glossary of Terms
Appendix B	Phase 1 Report
Appendix C	List of MH Documents
Appendix D-1	KPMG Review of the Consultant's December 4, 2006 Report
Appendix D-2	KPMG Review of the Consultant's January 2008 Report
Appendix D-3	KPMG Review of the Consultant's October 2008 Report
Appendix D-4	KPMG Review of the Executive Summary of the Consultant's October 2008 Report
Appendix E	Case Studies Review
Appendix F	Manitoba Hydro Power Sales and Operations 2009 Document
Appendix G	Manitoba Hydro's Long-Term Contracts for Export Sales
Appendix H	Manitoba Hydro Term Sheets for Export Power Sales
Appendix I	Manitoba Hydro Approvals Process for Long-Term Power Sales
Appendix J	Detailed Scenario Runs
Appendix K	Case Study Findings Relating to Risk Governance
Appendix L	Risk Definitions
Appendix M	Leading Practice Sources for Power Risk Management

Executive Summary

In 2005, Manitoba Hydro retained a consultant (the "Consultant") to assist with aspects of certain risk management practices. The Consultant's work led to a series of reports which contain assertions pertaining to Manitoba Hydro's export power sales and associated risk management practices.

KPMG LLP ("KPMG") was retained by the Board of Directors of Manitoba Hydro in November 2009 to carry out an independent assessment of its risk management practices ("Review") in its hydroelectric operations and to address the assertions raised by the Consultant.

KPMG is an audit, tax and advisory firm, and the Canadian member firm of KPMG International, a Swiss entity. KPMG International's member firms have 140,000 professionals in 146 countries. KPMG is an independent advisor with considerable experience in risk management practices in the public utility sector. KPMG has conducted many risk advisory engagements with leading organizations in this sector in Canada and around the world.

Scope of the Review

The scope of our review is as follows:

- review the assertions that have been made by the Consultant and the reports and services provided by the Consultant;
- identify the positions of Manitoba Hydro staff on each of the assertions and the services provided by the Consultant;
- perform a review and validation study of the merits of the Consultant's assertions and services; and
- prepare a report summarizing KPMG's findings.

KPMG's review examines certain risk management practices of Manitoba Hydro stemming from the assertions. Our scope is limited to key aspects of the hydroelectric operations of Manitoba Hydro and related corporate functions but does not include reviewing Manitoba Hydro's risk management practices as they apply to any other business products such as its natural gas operations, or to areas such as environmental and employee safety issues.

Background

The utility industry has undergone significant change in the last decade, including deregulation in some jurisdictions, the introduction of competitive energy markets across Canada and the United States, heightened environmental attention, fluctuating economic conditions and a continued focus on security of supply at reasonable prices for ratepayers. Taken together, these factors have significantly added to the complexity of managing risk. Most utilities are continually adapting their risk management practices to these changing circumstances.

Like its peers, Manitoba Hydro is subject to the impacts of these changes. Accordingly, Manitoba Hydro's operations have become, and will continue to be, more complex than ever before. This will continue to require further advancements in its modeling capabilities, export power sales practices, corporate risk governance, and power risk management practices. Manitoba Hydro has well established practices in place and a number of initiatives underway to improve its risk management practices. Many of our key findings reflect recommendations Manitoba Hydro should consider in further improving these practices.

Key Highlights

The Consultant has raised serious concerns as to the financial viability of Manitoba Hydro and the risk of major power outages related to its long-term export contracts. Further, the Consultant asserted in 2008 that Manitoba Hydro actions in the previous five years have cost the corporation in the range of $1 billion. Our approach has been to identify and analyze all of the alleged deficiencies in Manitoba Hydro's operations and have done so pursuant to our scope of work as detailed in the main report.

We are of the view that:

- there is no material risk that Manitoba Hydro is facing bankruptcy as a direct consequence of Manitoba Hydro's export sales practices;
- there is no material risk that Manitoba is facing power outages as a direct consequence of Manitoba Hydro's export sales practices;
- Manitoba Hydro's drought management strategies are prudent in the context of a hydro-based generation system;

- there is no evidence to support an assertion of losses approaching $1 billion in the five years cited, based on our analysis of Manitoba Hydro's modeling, export sales contracts and risk management practices;
- Manitoba Hydro has prudently utilized a strategy based on entering into long-term contracts and the securing of transmission rights in the development of its system; and
- Manitoba Hydro has operated in accordance with its legislative mandate.

Overall, in the context of its hydroelectric power operations, we are satisfied that Manitoba Hydro is following sound practices in its use of forecasting models, long-term power sales contracting, risk governance, and power risk management. Our report provides recommendations to Manitoba Hydro in order to continue to advance in these areas. Recommendations are contained within Chapters 3 to 6 of the main report and are summarized in the concluding Chapter 7.

Approach of the Review

KPMG's undertook the Review using a two-phased approach.

In Phase 1, KPMG undertook an initial assessment of assertions raised in the Consultant's Reports to identify the scope of the assertions and to develop an approach and work plan for the more detailed assessment that would be undertaken in Phase 2 of the Review. In Phase 2, KPMG undertook the work plan developed during Phase 1, and the results of conducting that work plan are provided in this report.

Phase 2 of the Review examined multiple lines of evidence for consideration, including:

- reviewing Manitoba Hydro documentation and data;
- interviewing Manitoba Hydro personnel;
- conducting analysis based on industry leading practices;
- conducting research of other electric utilities;
- consulting with specialized subconsultants;
- conducting literature reviews;

- analyzing third party data and reports;
- analyzing various financial and forecasting models used by Manitoba Hydro; and
- analyzing model runs conducted by Manitoba Hydro at KPMG's direction.

Issues and Themes

In undertaking the Review, KPMG analyzed the various assertions made by the Consultant in order to group related assertions that are within our scope into Issues. These Issues were then further grouped into four Themes. We define an Issue to be the components of an assertion(s) that reflect an alleged fundamental deficiency in Manitoba Hydro. The assertions made by the Consultant were considered in this process.

There are four Themes that were used in the conduct of our Review and the Issues within these Themes are outlined in the chart below:

- Forecasting models;
- Power sales management;
- Risk governance; and
- Power risk management.

The report contains a chapter on each one of the Themes. To appropriately assess the Issues contained within each Theme and to add value for Manitoba Hydro, our scope in certain instances extends beyond the matters addressed by the assertions.

Themes and Issues	
1. Forecasting models	
Issue 1	Appropriateness of inputs and model logic relating to pricing, water volume, key model parameters, lake water level balances and market rules
Issue 2	Treatment of optionality relating to plant cycling and storage
Issue 3	Validation of models
2. Power sales management	
Issue 4	Pricing methodology for firm power sales
Issue 5	Risk capital reserves
Issue 6	Long-term contracts structure
3. Risk governance	
Issue 7	Independence of the Middle Office function
Issue 8	Resourcing and authorities relating to energy risk management
4. Power risk management	
Issue 9	Treatment of risk (identification, measurement, treatment)

In this Executive Summary, for each of the four Themes, we have a section:

- identifying the Issues;
- providing operational context relevant to that Theme; and
- for each Issue, a summary of the Consultant assertions followed by KPMG's key findings.

These sections are followed by a brief conclusion.

Forecasting Models

We have reviewed the three key models (called HERMES, SPLASH and PRISM) used by Manitoba Hydro to support operations, capacity planning, and financial forecasting and budgeting processes. Of the three models reviewed, our focus was on HERMES because it plays the most important role with regards to the Issues pertaining to forecasting models.

We assessed the overall reasonableness of the modeling approach taking into account the use of the models, input assumptions, and evidence with respect to the models' effectiveness for their intended roles. Chapter 3 provides details on our analysis and findings.

Issues

With respect to forecasting models, KPMG addressed three Issues identified in the scope of work:

Issue 1: Appropriateness of inputs and model logic relating to: pricing, water volume, key model parameters, lake water level balances and market rules;

Issue 2: Treatment of optionality in terms of plant cycling and storage; and

Issue 3: Validation of models.

Operational Context

In evaluating the use of models at Manitoba Hydro, it is important to consider the context in which it operates and the types of decisions that the models are designed to support.

Water volumes at Manitoba Hydro are subject to wide swings from year to year. The year-to-year variation in water availability is much larger for Manitoba Hydro than for most other large hydroelectric utilities. The lowest flow year on record has less than 50% of the flow of the median year. The highest flow year is more than 50% greater than the median flow year. Hence the highest flow year is more than three times the level of the lowest flow year. The variability in water flows has important implications for the design of the system, Manitoba Hydro's export sale strategy, and the focus of modeling work.

Further, even within a year, future water flows are highly uncertain. Flow volumes can change dramatically based on the volumes of spring rain and, to a lesser degree, the extent of snow melt. Manitoba Hydro relies on its antecedent forecasting process in its production planning process, but the predictive power of this methodology is inherently limited. Antecedent forecasting uses regression analysis to predict future water flows based on current flows.

Uncertainty in water flows results in Manitoba Hydro selling much of its export power on a short-term basis in order to be highly confident that the power can be supplied. The percentage of Manitoba Hydro's export sales made on a short-term basis fluctuates year-to-year depending on water volumes, and is considerably higher in high flow years. For fiscal 2008/09, which had higher water flows than average, over one-half of sales were made in Real-Time or Day-Ahead markets as well as other short-term sales. For their spot market sales, Manitoba Hydro commits to deliver power, at most, one day ahead of time. Other opportunity sales are short-term, but are made outside of the spot market.

Manitoba Hydro also enters into long-term contracts which are serviced from "dependable energy". Dependable energy is the hydroelectric power available under the lowest river flow conditions in the historical record, and also includes energy sourced from wind and thermal as well as firm and contracted non-firm imports. (Although the definition of dependable energy contains a number of non-hydroelectric sources, these sources remain a very small share of Manitoba's total production.)

To account for uncertainty in its water supply, Manitoba Hydro is conservative in its export sales strategy:

- Long-term sales are limited to those that can be supplied from dependable energy.
- Opportunity sales made beyond the day-ahead and real-time markets are limited to those that Manitoba Hydro is highly confident can be supplied based on current water conditions.

As a consequence of the reliance on spot sales, changes in forecasts of future longer term production, because of changes in parameters in HERMES, do not lead to shortfalls in Manitoba Hydro's market position. Manitoba Hydro does not commit to opportunity sales that are based on uncertain water flows, and consequently does not incur contractual or market losses when medium and long-term forecast water flows do not materialize. This is an important factor to consider in evaluating the risks of financial loss.

In general, forward opportunity sales are not made unless Manitoba Hydro has sufficient firm capacity and energy resources to serve the load 95% of the time. This means there is only a 5% chance that such firm resources will be inadequate. For drought management planning, the required level of confidence in planning energy supply increases to 99%. This risk target reflects the combined probability of a severe winter (defined as a one in 10 event) and water supply at the 5th percentile level.

Models and their outputs are used as tools to support decision-making processes at Manitoba Hydro. The outputs from models do not directly lead to business or market actions and do not translate directly into financial profit or loss. For example, HERMES generates forecasts of available energy and suggested production schedules. These forecasts of available energy, however, are not translated directly by trading staff into forward market positions. Similarly, suggested production schedules produced by HERMES do not lead directly to control decisions at Manitoba Hydro hydroelectric facilities.

A key output of HERMES relevant to the scope of this review is a forecast of the amount of energy available for export within each segment of time modeled. This forecast is used as a reference point for assisting energy trading operations. Because of the priority of meeting domestic load before any energy export commitments, and due to the requirement to mitigate chances of there being insufficient resources to serve forecasted load, the Manitoba Hydro system is operated conservatively. Sales decisions are supported by various modeling tools within HERMES, such as load forecasting, water supply forecasting, capacity and reserve management, and deal analyzer modules.

Reliability issues are also addressed in model runs within HERMES. A standard run generates an economically optimal production schedule, based on its input assumptions. Manitoba Hydro then tests this projected production schedule against a scenario in which low water flows occur.

In the event that resources are projected to be inadequate to serve committed load, this will generally mean a draw-down in reserve storage levels, with a potential reduction in energy supply security in the second year of the projection horizon. In such event, water storage reserves will be replenished at the first opportunity, including from opportunity purchases and other non-firm sources.

Manitoba Hydro management has adopted a conservative management approach in recognition of the following:

- the duration and extent of a drought is not known in advance;
- it is normal for it to be very cold in the winter in Manitoba, which can cause loads to increase dramatically; and
- the societal and financial consequences of running short of energy during an extended period of drought (especially in the winter) can be enormous relative to the potential income that might be achieved by being less conservative.

Forecasting Models – Key Findings

This section outlines each issue and a summary of the Consultant assertions, followed by our key findings with respect to forecasting models.

Issue 1: Appropriateness of inputs and model logic relating to: pricing, water volume, key model parameters, lake water level balances and market rules

Pricing and Market Rules

The Consultant asserts that the HERMES model does not incorporate current market prices and that it needs to do so in order to serve as an appropriate basis for decisions made to release water. Specifically, the Consultant asserts that the prices used in the HERMES model should be updated regularly to reflect today's broker quotes and a true market environment. The Consultant asserts that not doing so prevents Manitoba Hydro from optimizing its financial performance in selling surplus power or buying hedges as these relate to decisions made to release water. The Consultant also asserted that the prices used in the Generation Estimate report and those used in the HERMES runs are inconsistent. It further noted that this exposes Manitoba Hydro to pricing error risks.

Findings

On pricing assumptions and market rules, we find the following:

- We have had extensive discussions with Manitoba Hydro staff on their approach for incorporating pricing and market rules for power purchases and sales into their planning models. We found that they apply appropriate care and due diligence in this process.

- In incorporating market price inputs, Manitoba Hydro needs to account for the various factors that will influence the prices that it will actually receive. We have found that Manitoba Hydro puts significant analytical effort into assessing these factors and accounting for them in its modeling approach. Furthermore, the analysis of price patterns is updated as new market data is accumulated over time.

- KPMG has examined the Consultant's assertions regarding inconsistencies between the Generation Estimate report and HERMES and we conclude that, based on the sample of cases reviewed, the quoted data inconsistencies arise out of a misinterpretation by the Consultant of the data that were being presented.

- At KPMG's request, Manitoba Hydro undertook a number of special runs of the HERMES model. These runs indicate that inefficiencies in operating schedules that could potentially result from stale or inaccurate price inputs are likely to have only a limited impact on the financial results achieved. Variation in water flow has a much larger influence on optimal schedules (and on Manitoba Hydro's financial returns). Constraints on import and export transactions, and the primary need to meet domestic loads, also have significant influence on production schedules.

Water volumes

The Consultant asserts that Manitoba Hydro's models sub-optimize the treatment of water volumes. Specifically, the Consultant recommends improvements to Manitoba Hydro's method of antecedent flow forecasting (e.g., use of backtesting to validate the antecedent forecasting methodology). The Consultant also has concerns about the validity of using historical water flow data in the models. The Consultant identifies a number of years which mark the addition of gauging points and hence improvements in the quality of water data. As a consequence, the Consultant suggests that water flow data from prior to 1942 are unreliable.

Findings

With respect to flow forecasting and historical water flow data, we find the following:

- Manitoba Hydro's process for antecedent forecasting of water flows is reasonable. Underlying relationships used in this process are statistically significant. Moreover, linear regression, which is the basis of Manitoba Hydro's antecedent approach, has been a standard industry approach to seasonal stream flow forecasting for many years.

- For general forecasting and planning purposes, it is reasonable to rely on historical water flow data as model inputs. We found a number of other North American hydroelectric utilities that use a similar practice.

- Given the uncertainty of impacts from climate change, Manitoba Hydro may wish to formally examine the potential impact of changes in water flows from the historical pattern. Further, it may also wish to undertake scenario analyses to assess the financial impact of droughts worse than those found in the historical record.

  This type of scenario analysis can be used for the purpose of risk analysis, and does not necessarily need to be used as the basis of financial forecasts or for the determination of dependable energy. Manitoba Hydro's current approach to forecasting and to calculating dependable energy is reasonable and consistent with practices at other utilities.

- With respect to the Consultant's assertion that the water flow data prior to 1942 are unreliable, we found that the period prior to 1942 is characterized by lower estimated water flows relative to the full period. Hence, forecast production would be higher if these data were excluded from the water flow records. Including data from this earlier period adds an element of conservatism to Manitoba Hydro's financial forecasting process.

Key model parameters

The Consultant asserts that the SPLASH and HERMES models utilize different sets of internal model parameters (production coefficients) for the conversion of water flow to power at each hydro plant. The Consultant further noted issues regarding some approximations in the HERMES model as well as the use of "model adjustment factors" (which are sometimes manually changed). The Consultant recommended that Manitoba Hydro undertake on-going calibration and updates to both of these models.

Findings

With respect to the various matters raised by the Consultant regarding key model parameters, we find the following:

- We are satisfied that Manitoba Hydro has taken appropriate care and due diligence in modeling production coefficients in its modeling tools. Further, Manitoba Hydro carefully takes into account plant efficiency when optimizing the scheduling of its hydroelectric stations.

- We are satisfied that Manitoba Hydro has taken appropriate care and due diligence in developing, operating and maintaining the models. This relates to the approximations in the HERMES models, the use of adjustment factors, and the on-going calibration and updates to both SPLASH and HERMES. In the main report, we present recommendations for Manitoba Hydro to improve its maintenance of the models.

Lake water level balances

The Consultant notes that the SPLASH model assumes "perfect foresight" of water flows and hence assumes lake ending levels which in the real world are impossible to attain. This raises concerns with respect to the calculation of the costs of a drought.

Also, the Consultant raised concerns about the reconciliation of lake level balances in the financial forecasting process.

Findings

With respect to these matters, we found the following:

- SPLASH is used for long-term forecasting purposes and to estimate the financial impacts to Manitoba Hydro of drought.

- There are a variety of factors that complicate the calculation of drought costs. On one hand, SPLASH is based on "perfect foresight" and will assume that energy stored in reservoirs is used to the fullest extent possible. In practice, Manitoba Hydro management will operate the system more conservatively than assumed by SPLASH. In doing so, Manitoba Hydro management will maintain reservoir levels at higher levels in order to address the fact that a drought may last longer than the historical record assumed within SPLASH. This may lead to higher actual operating costs in the period of the drought than calculated by SPLASH. Higher costs are the result of scheduling additional imports and fossil fuel purchases (i.e., costs associated with not releasing water from storage at what might appear to be optimal times).

  On the other hand, SPLASH may overestimate fossil fuel costs because it ignores the potential to import power on a non-firm basis. SPLASH assumes that imports only occur under Manitoba Hydro's Diversity Contracts, which are considered firm. The ability to schedule opportunity purchases through the spot market and from short-term contracts, thereby reducing fuel purchases, is not considered in SPLASH. In part, higher actual costs in the period of the drought as a result of conservative reservoir management just reflect the movement of costs for reservoir replenishment forward from future periods. However, there may also be opportunity costs associated with the increased risk of water spillage, in the event that water flows after the drought are very high.

- The impacts of these various factors on estimates of drought costs could be separately quantified by Manitoba Hydro staff in order to improve stakeholders' understanding of their implications. If a material result is identified, this can then be better communicated to users of the financial information.

- To address specific concerns of the Consultant about the reconciliation of lake level balances within HERMES, we also conducted an analysis of the financial impact of lake level discrepancies observed in the 2006 Generation Estimate

Report ("lost water"). There were discrepancies in lake levels on eight of the 29 lakes modeled although the discrepancies were generally small. By applying factors representing the change in water storage with lake levels, the amount of energy per unit of water stored, and the market price of power, we estimate that projected revenues post-2006/07 were understated by about $0.98 million, because of "lost water". The amount of the discrepancy was small (less than 0.2 percent) of total water in storage.

- We checked for similar discrepancies in the Generation Estimate reports supporting Integrated Financial Forecast ("IFF") processes for subsequent years. As at April 1st, 2008, discrepancies were even smaller than in 2007. At an estimated 2,800 MWh, the discrepancy had an estimated financial value of $140,000. The discrepancy at April 1st, 2009 was negligible. Such discrepancies, in addition to being small, have been significantly reduced over time.

Issue 2: Treatment of optionality in terms of plant cycling and storage

The Consultant notes a variety of deficiencies in the modeling of storage optionality, which is the financial value associated with the flexibility to change storage levels in a hydroelectric system. As a result, the Consultant asserts that Manitoba Hydro does not effectively capture or optimize the value of hydroelectric storage. In particular, the Consultant alleges a variety of deficiencies with respect to the modeling of storage in HERMES. The Consultant identifies, among other issues, differences between the HERMES and SPLASH models in their decision making with respect to the use of water in storage and in identifying target ending reservoir levels.

Findings

With respect to storage optionality and target lake ending levels, we find the following:

- Both HERMES and SPLASH use linear programming routines to identify optimal production decisions under input scenarios that specify loads and water resources, in addition to other production variables, over a planning horizon. Neither HERMES nor SPLASH explicitly address uncertainties in input variables during their optimization routines. As such, neither model identifies the "option value" of storage. Rather, the models incorporate the value of storage under expected conditions in determining optimal production decisions. It is not necessary for the models to identify an explicit "storage option value" for the purpose of production scheduling.

The HERMES system is used in the planning of operations over a short-term horizon, while SPLASH is used over a longer-term horizon to plan facility additions. Because HERMES is used to support current operational decisions, it has more detail with respect to system operations, and produces financial forecasts that more accurately reflect the realizable value of storage.

- Relative to SPLASH, the HERMES optimization approach provides for more explicit consideration in the production scheduling decisions of the economic value, relative to current sales, of greater or lesser ending storage levels. This seems appropriate given that HERMES is the tool that has the greatest impact on actual operations in the near term. Decisions in the near term, as supported by HERMES, can respond to prices that are currently observed in the market. As a longer-term tool, SPLASH has less need to adjust decisions based on current market data. Rather, it simply needs to capture the "average" or expected economics of a particular decision or sequence.

In summary, we note that neither HERMES nor SPLASH were designed to be financial trading models or to provide estimates of the market value of storage. Both HERMES and SPLASH are water management models designed to meet Manitoba Hydro's operational needs in serving its firm load.

Issue 3: Validation of models

Forecasts from models, such as HERMES and SPLASH, are based on inputs and model logic (i.e., the formulas and computational methods embedded in the model). Forecasts generated from models could conceivably be inaccurate either because of flaws in the model logic or errors in the inputs to the model (which are typically forecasts themselves).

Backtesting is a means by which errors in the inputs can be removed in order to verify the appropriateness of the model logic. The Consultant asserts that Manitoba Hydro does not back test its HERMES or SPLASH models. Accordingly, the Consultant argues that management decisions and reports based on the outputs of these two models may be flawed.

Findings

With respect to the validation of the HERMES and SPLASH models, we find the following:

- HERMES is the main tool used to support operations scheduling. Modules within HERMES represent the Manitoba Hydro system in a significant amount of detail. These modules have been developed and regularly updated over many years and reflect extensive work to calibrate model outputs to actual system performance and thereby continually validate the model.

- SPLASH is a simulation tool designed to support Manitoba Hydro's long-range system planning. The output from the SPLASH model provides information used to evaluate the economics of power resource options such as power export marketing contracts, system enhancements and surplus energy rate programs. SPLASH is also used to support financial forecasting. Similar to HERMES, SPLASH personnel validate the model by performing quality control checks with respect to actual system performance.

- In addition to the current validation procedures used for HERMES and SPLASH, Manitoba Hydro should consider incorporating backtesting practices to validate its models. We found no evidence that that there are any material errors or flaws in the management reports generated by using these two models.

- Given ongoing evolution in modeling, Manitoba Hydro should continue to examine potential alternative approaches to production and system planning. Consistent with this recommendation, Manitoba Hydro's plans for model development indicate that it is continuing to enhance the system over time. Formal peer review or benchmarking exercises might also help ensure that Manitoba Hydro benefits from experience gained elsewhere.

- Manitoba Hydro has developed its models in-house and thus has relied heavily on the internal expertise of a small group of skilled, experienced staff who are interested in improving the performance of the decision-support tools on an ongoing basis. A significant amount of their expertise is derived from on-the-job training and experience gained in using the models in a "live" environment. This creates some risks with respect to knowledge sharing and corporate exposure to the potential departure of key personnel.

- KPMG recommends that Manitoba Hydro develop more formal model documentation. Such documentation will reduce risks associated with the departure of key modeling personnel and it will help internal and external stakeholders better understand and accept model structure and logic. The development of documentation will require additional resources.

Power Sales Management

We examined key issues associated with Manitoba Hydro's practices of entering into long-term fixed price contracts for export power sales. Manitoba Hydro has and continues to enter into long-term fixed price contracts for export power sales primarily with counterparties in the MISO marketplace. Chapter 4 provides details on our analysis and findings.

Issues

With respect to power sales management, KPMG addressed three Issues identified in the scope of work:

Issue 4: Pricing methodology for firm power sales;

Issue 5: Risk Capital Reserves; and

Issue 6: Long-Term Contracts Structure.

Operational Context

In order to fulfill its legislative mandate, Manitoba Hydro has, by design, more installed capacity than Manitoba demand and therefore is in a position to produce electricity in excess of what is consumed in Manitoba. This is not a recent circumstance, but has been the case for much of Manitoba Hydro's history. For example, in fiscal 2008/09, Manitoba Hydro had an installed system capacity of 5,480 MW with a Manitoba firm peak demand (occurring in the winter) of 4,477 MW. In the same fiscal year, the total energy supplied by Manitoba Hydro's system (other than isolated generation capabilities in remote communities) was 34.5 TWh whereas Manitoba consumption was 21.3 TWh.

A key consideration in Manitoba Hydro's capacity planning process is the variation in water flows. For meeting its projected load, Manitoba Hydro relies only on dependable energy, which is the energy that will be available in the lowest flow year. Additional or surplus energy may be available in most years, but this cannot be counted on to meet Manitoba Hydro's firm loads and firm export commitments.

Because of the need to provide energy on a firm basis, the amount of dependable energy available, rather than the amount of installed capacity, becomes the key planning criteria. Another way of saying this is that the Manitoba Hydro system is energy limited, rather than capacity limited. In this framework, dependable energy is the energy metric of relevance.

The addition of new hydroelectric generating capacity generally increases the amount of dependable energy available. This reflects the fact that the installation of new hydro generating plants allows Manitoba Hydro to extract more energy from a given amount of water flowing into the Manitoba Hydro system. More precisely, the addition of a new hydroelectric plant allows Manitoba Hydro to capture additional "head", or energy from the drop in the elevation of water, as a unit of water flows down to Hudson Bay.

Although dependable energy is the key system constraint, Manitoba Hydro's financial plans need to take account of the fact that more energy will generally be available in anything other than a low-flow year. This additional energy is known as surplus energy. The amount of surplus energy available in any year varies widely. Financial plans are developed by averaging the results of alternative water flow scenarios. Water flow scenarios are based on the historical record of water flows. The average amount of surplus energy available across the various water flow scenarios can be referred to as the expected surplus energy. As described earlier, surplus energy has generally been sold on a short-term basis in export markets. These short-term sales, which are linked to surplus energy, are referred to as opportunity sales.

For capacity planning purposes, Manitoba Hydro has established the following power resource planning criteria:

- *Capacity Criteria — Manitoba Hydro will plan to carry a minimum reserve against a breakdown of plant and an increase in demand that is 12% above the Manitoba forecast peak demand each year plus the reserve required by any export contract in effect at the time.*

- *Energy Resource Planning — The Corporation will plan to have adequate energy resources to supply the firm energy demand in the event that the lowest recorded coincident river flow conditions are repeated. Planning studies, to meet the firm energy demand, may include up to a maximum of 10% of the energy demand in Manitoba to be supplied from the energy reserves on interconnected utilities, provided an energy purchase contract is or will be in effect during the time being studied.*

In addition to the surplus capacity required by Manitoba Hydro's power resource planning criterion, another key reason that Manitoba Hydro has surplus energy production capability is that hydroelectric plants tend to be built in "chunks", i.e., there are large capacity additions at a single point in time to take advantage of economies of scale in plant development, whereas Manitoba load tends to grow in a steady manner year over year. Thus, every time a plant is built, Manitoba Hydro will have excess dependable energy until such time that the incremental Manitoba load "catches up" to the incremental resources added to the system. This excess dependable energy can be used by Manitoba Hydro to generate firm energy that is surplus to Manitoba requirements and that can be exported.

At the extremes, Manitoba Hydro has two basic mutually exclusive options to sell its surplus energy in the export markets, each with its own risk-reward profile:

- Sell all the excess energy as spot sales (e.g., MISO DA and RT markets). Key risks that Manitoba Hydro takes on under this option include:
  - "missed opportunity regret" risk (spot prices may turn out to be below the price that would have been available under contract);
  - spot price volatility risk resulting in revenue volatility and times when spot prices may drop resulting in a revenue deficiency relative to the fixed costs of Manitoba Hydro leading to a corresponding rate increase for Manitoba ratepayers; and
  - sales volume risk (there may not always be enough transmission capacity south of the US border for the available excess energy).

Sell all the excess energy at fixed price short-term and/or long-term contracts. Key risks that Manitoba Hydro takes on under this option include:

- "sellers regret" risk (spot prices may turn out to be above the contractual fixed price);
- sales volume risk (there may not always be enough transmission capacity, especially for short-term contracts, or a drought results in Manitoba Hydro having to purchase replacement energy to fulfil its contractual obligations leading to a corresponding rate increase for Manitoba ratepayers); and
- amplified drought risk (to the extent contracts are for firm amounts of energy).

Manitoba Hydro has chosen to export market its surplus energy using a combination approach of spot sales and short-term/long-term contracts. Over the last decade, approximately 30 percent of Manitoba Hydro's hydroelectric production has been used for export, with slightly under one-half of those exports in contractual firm sales and slightly over one-half of those exports in opportunity sales, for example, spot sales on the day ahead and real time markets.

MISO on-peak prices declined significantly in 2009 relative to 2008. Average prices in 2009 are less than one-half of 2008 prices. The price decline reflects both a decline in natural gas prices, and a drop in electricity loads associated with the economic downturn.

The price decline highlights the risk for Manitoba Hydro in relying entirely on spot markets for its electricity sales. Revenues could decline dramatically in the event of a market downturn. This is particularly a concern where revenues are used to support investment in new hydroelectric generation. The capital costs and associated debt charges as a result of new generation are fixed in advance. This suggests that a portion of the revenue should also be fixed in advance, as Manitoba Hydro does.

Manitoba Hydro's rationale for entering into long-term fixed price contracts as part of its power sales mix can be summarized as:

- Risk mitigation;
- Securing access to firm transmission; and
- Lower rates for Manitoba ratepayers.

Prices, terms and conditions in a long-term firm power sales agreement are negotiated between the parties. Prices, terms and conditions, should generally reflect the allocation of risk under the contract as well as the value received by each party. Both parties to the contract will enter into the agreement only if they both perceive that there are "gains (financial and non-financial) from trade," meaning that the contract provides both parties benefits that they perceive are greater than the costs.

Were Manitoba Hydro to attempt to extract all of the gains from a trade, there would probably be no transaction because the counterparty would see no gains from trade. Such a result would likely harm the Manitoba ratepayers, as the counterparty would not undertake the investments in transmission on their side of the border, and the market access benefits as a result of increased market access in the event of drought would not accrue to Manitoba ratepayers. Manitoba Hydro has a number of existing and proposed long-term contracts, mainly with Northern States Power, Minnesota Power and Wisconsin Public Service.

Whether Manitoba Hydro has extracted all it could from its counterparties in negotiating long-term firm power sales contracts is easy to second guess. However, the existence of the contracts suggests that both counterparties (the seller and the buyer) saw some gain from trade in the deal; otherwise they would not have entered into the agreement.

Future market prices for power are always uncertain. Uncertainty stems from many sources, including the future electricity market structure, load growth, government regulation, capital costs for new generation, fuel costs, and emission costs. Despite these uncertainties, utilities make long-term resource commitments in the form of long-term contracts and construction of new generation facilities.

Manitoba Hydro policy considers these uncertainties as follows. First, a price based on the average of price forecasts purchased from multiple power price forecasting
MH 4 consultants is calculated. A [redacted] is then [redacted]o this result. Second, Manitoba Hydro policy calls for the calculation of the avoided cost of the potential counterparties as a benchmark against the long-term price forecast. Pricing a contract using counterparty's avoided cost is a well established pricing methodology in the utility industry. Developing these two price estimates provides an indication of the potential range of a contract's price.

Manitoba Hydro's "Diversity Agreements" are another aspect of its power sales risk mitigation strategy. Manitoba Hydro has significant surplus capacity in the summer season, when its energy requirements are low, but lower capacity in the winter season, when its energy requirements are high. To balance seasonal capacity and energy requirements, Manitoba Hydro has entered into a number of agreements to exchange capacity and associated energy with the counterparties that have power systems whose peak loads occur at different times in a year, i.e., Diversity Agreements.

Manitoba Hydro has a total of 500 MW of Winter/Summer Season capacity exchange available under Diversity Agreements. The Diversity Agreements also provide for certain energy guarantees which enable access to additional capacity in the event that Manitoba Hydro is experiencing adverse water conditions.

Power Sales Management – Key Findings

This section outlines each issue and a summary of the Consultant assertions, followed by our key findings with respect to power sales management.

Issue 4: Pricing methodology for firm power sales

The Consultant asserts that Manitoba Hydro is using incorrect pricing methodologies for the sales price in long-term energy contracts. Specifically, the Consultant asserts that Manitoba Hydro is not properly making use of current market price information and is not properly identifying and quantifying all the risks (e.g., liquidated damages, volumetric risk, etc.) associated with such long-term supply contracts. As a result, the Consultant asserts that Manitoba Hydro is not building in an appropriate premium in pricing these contracts.

The Consultant acknowledges the reasons cited by Manitoba Hydro as to why it was willing to sell power for less than its apparent market value in these long-term contracts (i.e., because of the creation of transmission capacity and access), but rejects these as being valid reasons for such pricing. In this context, the Consultant recommends an overhaul of the pricing methodology used in the long-term fixed price contracts for energy sales.

Findings

With respect to the Manitoba Hydro's methodology for firm power sales, we find the following:

- Prices in long-term contracts are a matter of negotiation between the parties, and must be acceptable to both parties for a deal to be done.

- In the course of negotiating these contracts, Manitoba Hydro develops reference prices based on the two methodologies described above. Developing these two price estimates provides Manitoba Hydro with an indication of the potential range of a contract's price. Based on this information and leveraging the considerable industry experience of the key Manitoba Hydro personnel involved with the negotiations, a mutually agreeable price is set in the term sheets for new long-term contracts.

- Based on our analysis of this pricing process, Manitoba Hydro has an appropriate methodology for arriving at the sales price in its long-term contracts. As mentioned previously, the pricing methodology explicitly incorporates relevant market pricing forecasts and, further, includes a [redacted] And as detailed in MH 4

Chapter 4, long-term contracts mitigate Manitoba Hydro's market risk through diversification of its export sales mix, and mitigate its drought risk because of both the returns generated by the contracts and the creation of the transmission capacity.

- Related aspects of this Issue are addressed in Issue 9.

Issue 5: Risk Capital Reserves

As described in the Issue above, the Consultant asserts that Manitoba Hydro is using incorrect pricing methodologies for the sales price in long-term contracts and in particular is not properly identifying and quantifying all of the risks associated with having entered into long-term supply contracts. In that context, the Consultant asserts that Manitoba Hydro is also not reserving a sufficient amount of risk capital for the export sales business, in light of its drought risk. The Consultant recommends the immediate cessation of export power market sales under long-term contracts until Manitoba Hydro has an appropriate amount of risk capital reserved for this business.

Findings

- As stated in our findings related to Issue 1 and Issue 4, we are satisfied with the methodology used by Manitoba Hydro in arriving at the sales prices in its long-term contracts and in the treatment of lake water level balances in the quantification of drought risk.

- Further to the analysis described in Issue 1, KPMG asked for additional stress tests of Manitoba Hydro's preferred expansion plans (which include new long-term contracts) incorporating various drought scenarios and market price scenarios. KPMG also asked for corresponding stress tests to be conducted for an alternative expansion plan that did not include new long-term contracts. The results of these stress tests indicate that Manitoba Hydro's ability to withstand the financial impacts of a drought is improved under the expansion plan that includes new long-term contracts.

- To summarize, on the basis of the policy decisions in place with respect to risk tolerance, Manitoba Hydro quantifies its drought risk appropriately and currently provides for appropriate levels of reserves of risk capital against its projected drought risk.

Issue 6: Long-Term Contracts Structure

The Consultant asserts that Manitoba Hydro has suboptimized these arrangements due to the use of certain terms in the long-term contracts. The Consultant recommends: significantly shortening the duration of these contracts; sharing of risk in the market prices and premiums being charged including index or floating price provisions; and increasing optionality to Manitoba Hydro's benefit.

Findings

- As with prices, contractual terms in long-term agreements are a matter of negotiation between the parties, and must be acceptable to both parties for a deal to be done.

- The provisions identified by the Consultant, as well as other comparable novel terms, change the nature of the commercial arrangement for Manitoba Hydro and the counterparty by either making the contract riskier for the counterparty or changing the nature of the product. Without knowing how the counterparties would value such changes, it is speculative to determine whether such provisions would help or hurt. Manitoba Hydro's costs would increase, potentially significantly, if it were to commit to multi-billion dollar capital investments with contractual sale commitments of shorter durations (e.g., two years), potentially rendering the projects infeasible.

- Optimal risk sharing in a contractual arrangement dictates that risk should be allocated to the party that is best able to manage that risk. In this context, as addressed in Chapter 4, many of the potential novel terms that could be considered in a long-term firm sales contract between Manitoba Hydro and a counterparty involve shifting a particular risk to the counterparty. In many cases, however, Manitoba Hydro would generally be in a better position to assess and/or manage the risk than the counterparty, and would therefore generally be better off in the long run if it retained the risk (e.g., by being compensated for retaining the risk or avoiding the costs associated with transferring the risk).

- Overall, we found no basis to conclude that Manitoba Hydro had suboptimized its contractual provisions.

Risk Governance

We reviewed risk governance at Manitoba Hydro. Risk governance addresses the roles, responsibilities, reporting relationships and policies to support decisions about risk that may enhance or threaten an organization's achievement of objectives. Our assessment of Manitoba Hydro's risk governance has been carried out with respect to its opportunity power sales risk management function. Chapter 5 provides details on our analysis and findings.

Issues

With respect to risk governance, KPMG addressed two Issues as identified in the scope of work:

Issue 7: Independence of the middle office functions; and

Issue 8: Resourcing and authorities relating to energy risk management.

Operational Context

Risk governance has become increasingly important to power utilities for reasons such as the introduction of competitive markets, the recent turmoil experienced in financial markets and complex capital projects.

The power sales risk management functions may be divided into long-term sales and opportunity sales, which is the topic of this chapter of the report.

Manitoba Hydro's business model is built on a combination of domestic Manitoba sales, long-term contracts to export customers, and opportunity sales to extraprovincial and export customers. Opportunity sales are the responsibility of the Power Sales & Operations Division ("PS&O"), with day-to-day oversight from the Middle Office.

Manitoba Hydro's approach to power sales is that they are asset backed. That is, the water resources needed to generate the power are known to exist (with a high level of confidence) prior to the actual sale of the energy. Opportunity sales do not characteristically present high levels of risk for electric utilities, as they are made on a real-time basis, or day-ahead basis. Some volatility may exist on price, but the supply of, and demand for, the energy is known by Manitoba Hydro staff with a high degree of certainty.

This contrasts with a speculative trading business model that trades energy and holds open positions, based on a market view. Manitoba Hydro is not a trader of energy that takes speculative positions into the future. Manitoba Hydro's primary business objective is to provide low cost and reliable energy services to its domestic customers and optimize its assets and excess energy supply.

The risk management activities related to opportunity export power sales are transactional in nature – and within the purview of the PS&O Division. It is these transactions that the Middle Office is focused on monitoring to ensure that they are made in compliance with Manitoba Hydro policies and procedures.

Risk Governance – Key Findings

This section outlines each issue and a summary of the Consultant assertions, followed by our key findings with respect to risk governance.

Issue 7: Independence of the middle office functions

The Consultant asserts that, as Manitoba Hydro integrates risk management into its corporate framework, it is imperative to segregate the duties involved in calculating and reporting the risk and financial exposure of Manitoba Hydro from the business units responsible for operating level decisions, trading and opportunistic deals. The Consultant asserts that segregation of these duties is an important internal control element of compliance programs because it mitigates errors and opportunities for corporate fraud and misstatement of financial earnings. The Consultant's assertion is that it is important for the middle office function to have an independent reporting relationship.

Findings

- The Export Power Middle Office (EPMO) is a single, independent, risk management function. It reports to the manager of Corporate Risk Management, who in turn reports to the Chief Financial Officer. It is independent from the Power Sales and Operations (PS&O) Division. It is steadily progressing in terms of its responsibilities for measuring, monitoring, controlling, and reporting the risks associated with PS&O's transacting activity. The progress made by the EPMO is consistent with the pace of change identified at other electric utilities in our case study research and continued progress is suggested.

Issue 8: Resourcing and authorities relating to energy risk management

The Consultant asserts that the energy risk management function of Manitoba Hydro does not meet best practices. Specifically, the Consultant notes that there are limited risk management policies with inadequate ability for the Middle Office to perform an oversight role over PS&O and trading transactions. The Consultant infers that relevant risk management reports are not being utilized in the management of risk at Manitoba Hydro. The Consultant argues that it is common industry practice for risk management to monitor on a regular basis market price and hedging valuations in order to manage corporate performance in line with the achievement of the IFF.

Findings

- Manitoba Hydro's risk power sales governance practices compare favourably for the most part to leading practices. Based on the nature of its asset backed power sales business model, the risk governance practices at Manitoba Hydro are, for the most part, appropriate. The comparative analysis conducted by KPMG to other electric utilities demonstrates that Manitoba Hydro's risk management practices are consistent with other utilities of similar size.

- Based on the size and nature of the asset backed power sales strategy adopted by Manitoba Hydro, the independent reporting relationship of the Export Power Middle Office to Corporate Risk Management and the Chief Financial Officer is in keeping with leading practice.

- The power sales risk management policy framework substantially meets the leading practice.

- Manitoba Hydro should continue to institutionalize the policy setting roles of the Export Power Middle Office and fully align its power sales risk management policies with leading practices for market, credit and contractual risk management. The current middle office structure partially meets the leading practices.

  In order to fully meet the leading practice, credit risk analysis should report directly to the Middle Office. The market risk quantification capabilities of the Middle Office should be enhanced. The HR and technology resources of the Export Power Middle Office to conduct independent risk assessments of power sales partially meets the leading practice.

Manitoba Hydro should also continue its efforts to enhance the resources of the Middle Office through the addition of a market risk analyst. The credit risk analyst positions which currently report to the Contracts Administrator within the Export Power Marketing Group should report directly to the Middle Office. For operational efficiencies continued effective working relationships within the Export Power Marketing Group, these positions could continue to physically reside within PS&O.

Manitoba Hydro should also continue to actively define its functional requirements (including risk metrics) and continue its efforts to acquire a risk analysis software tool to enhance the analytic capability of the Middle Office.

Power Risk Management

Our analysis of power risk management examined issues in the context of a risk management framework with the following elements: risk identification; risk measurement; risk control; and risk reporting. Chapter 6 provides details on our analysis and findings.

Issues

With respect to power risk management, KPMG addresses the Issue identified in the scope of work:

Issue 9: Treatment of risk (identification, measurement, treatment).

Operational Context

Our approach to assessing power risk management at Manitoba Hydro is based primarily on the following:

- review of how power risk is managed at Manitoba Hydro;
- review of risk management leading practices in the energy industry; and
- review of applicable risk management practices from other electric utilities.

It is important to note that leading practices are aspirational, continue to evolve and are subject to limitations. Leading practice is a directional compass for an organization's risk management development. However, the development and implementation of such practices does not assure that risk control objectives will always be achieved. Many leading practices are adopted from the requirements of organizations that primarily transact and manage risk in the more traditional financial markets. Requirements of organizations transacting in the energy markets can be different, and in this context, leading practices should be modified accordingly. In addition, the adoption of leading practices should be considered in the context of costs versus benefits.

Our analysis of power risk management examined issues in the context of a risk management framework with the following elements:

- risk identification;
- risk measurement;
- risk control; and
- risk reporting.

Risk identification is a requisite component of an effective risk management framework. Before a company can begin managing its inherent risks, the risks must be identified and defined. Management consensus on key risk categories (e.g., market, credit, operational, regulatory, legal, environmental, reputational, etc.) and corresponding definitions establishes the company's risk taxonomy. The area of Manitoba Hydro's power risk management where risk identification is critical relates to its export power sales. This is because non-export sales are made in the context of a regulated utility environment. Within export power sales, it is primarily long-term contracts that raise issues related to risk identification (and measurement and mitigation) because short-term contracts are low risk. This is where we focused our analysis.

Risk measurement refers to a company's quantification of its risk exposures. Risk measurement is a prerequisite step to risk mitigation and hedging, and should be comprehensively applied to firm-wide risks. However, not all risks are readily quantifiable. In circumstances where quantification is not a feasible option, qualitative measures are a suitable alternative. In power sales, risk measurement is primarily tied to the assessment and reporting of fair value (mark-to-market) and risk exposure (at-risk measures, stress testing) amounts associated with an organization's open commodity positions. Risk measurement leads to financial performance measures to mitigate earnings volatility, evaluate profit drivers, manage credit risk, assess hedge effectiveness and efficiently allocate risk capital.

Risk control is a set of tools to manage risks associated with energy transacting activities in a prudent manner. It is an important distinction to understand that risk controls do not, in themselves, reduce risk. Instead, controls represent how much risk an organization is willing to accept. Controls are a direct reflection of a company's risk tolerance defined as the "acceptable level of variation relative to achievement of a specific objective."

We assessed two common risk controls: risk limits and transaction processing controls. Risk limits are designed to manage the magnitude of variance in market and credit exposure. Transaction processing controls are designed to manage the magnitude of variance in operational costs associated with human error.

Risk reports are regularly disseminated throughout an organization to convey exposures and business unit performance to executive management, the risk management committee and the Board of Directors. A meaningful package of risk reports summarizes portfolio positions, market and credit exposures against limits, financial performance and probabilistic risk measurement. Risk reports are typically generated and prepared by an independent function in order to ensure objectivity and accuracy.

Effective risk reports are in a format that can be easily read and understood by executive management and the Board. A timely, comprehensive suite of risk reports are designed to help management monitor and make informed decisions regarding market, credit, drought and operational exposures.

Manitoba Hydro is a unique utility holding a natural long position in energy supply. Manitoba Hydro's experience transacting in the extraprovincial wholesale electricity business initiated with the first transmission interconnection in 1958. Short-term trading began in 2001.

Manitoba Hydro participates in the wholesale energy markets by exporting surplus power only to capture market opportunities, generate incremental income, and to ensure market access for current and future domestic needs.

The overall breadth of Manitoba Hydro transacting activities are low risk in nature due to the short duration of the majority of its power trading activities. Coupling the low risk with the conservative risk management practices in place, Manitoba Hydro manages its market, credit and volume risks in a prudent manner.

In essence, the analysis and recommendations consist of comparing Manitoba Hydro's practices with leading practices (and case study information where applicable) in order to identify gaps and opportunities for improvement, and as such, are tactical in nature.

Power Risk Management – Key Findings

This section outlines the issue and a summary of the Consultant assertions, followed by our key findings with respect to power risk management.

Issue 9: Treatment of risk (identification, measurement, treatment)

The Consultant asserts that Manitoba Hydro is not adequately analyzing its risks associated with export power sales by breaking the risks into its component sub-risks and using a structured framework for assessment. The assertions relate to risk identification, risk measurement, risk control and risk reporting.

Findings

In the context of risk identification:

- While Manitoba Hydro has documented contract review procedures, they do not explicitly include risk identification, assessment and risk mitigation strategies. Manitoba Hydro should consider expanding these procedures to include these items.

- Major export contracts undergo extensive review by internal stakeholders prior to executing binding term sheets. We suggest that the Middle Office also be involved in the review of export contracts.

In the context of risk measurement:

- Manitoba Hydro should consider extending its current practices of using Mark-to-Market (MTM) methodologies to measure and monitor its short-term physical transactions and its credit risk exposures (i.e., replacement cost);

- Manitoba Hydro quantifies drought risk using a non-probabilistic stress test, an appropriate measure. Manitoba Hydro should also consider developing a probabilistic stress test to further assist management decision-making.

In the context of risk control:

- Manitoba Hydro has specified risk limits limited to "Power Related Transactions" in the area of Merchant Transactions (Related or Pure Merchant) and Customer Credit. Manitoba Hydro continues to enhance its limit structure, for example, by recently establishing Stop Loss Limits. We recommend that Manitoba Hydro continue developing further limits such as Value-at-Risk (VAR) limits for Related Merchant Transactions.

- Manitoba Hydro employs a wide range of control mechanisms to mitigate operational risk throughout the transaction process in a reasonable manner. Based on our experience with peer utilities, Manitoba Hydro transaction controls are consistent with prevalent practices.

In the context of risk reporting:

- Manitoba Hydro risk reporting is generally consistent with leading practice except in the area of "Exposure vs. Limits" reports. We recommend Manitoba Hydro expand its report suite to include this key report.

- Variance reports are produced at Manitoba Hydro to compare actual against forecasted data for all of its forecasted data and in adequate detail and structure.

Conclusion

- Manitoba Hydro is subject to the impacts of ongoing changes in the utility industry. Accordingly, Manitoba Hydro's operations have become, and will continue to be, more complex than ever before. This will continue to require further advancements in its modeling capabilities, export power sales practices, corporate risk governance, and power risk management practices.

- With respect to the modeling approach at Manitoba Hydro, we find:

– Manitoba Hydro has developed a suite of models that capture the key characteristics of the Manitoba Hydro system. These models are used to help optimize system operations and to support long-term capacity planning.

– We are satisfied that Manitoba Hydro has taken appropriate care and due diligence in developing and maintaining these models and in using them in its operations planning process.

– Manitoba Hydro's current approach to forecasting and to calculating dependable energy appears reasonable and is consistent with practices at other North American hydroelectric utilities. It is reasonable to rely on historical flow data for estimating dependable energy.

- With respect to long-term contracting for export power sales, it is our opinion that:

– Manitoba Hydro has made appropriate strategic choices in entering into long-term fixed price contracts for export power sales;

– Manitoba Hydro has appropriately established the firm export volumes in these contracts; and

– Manitoba Hydro has an appropriate methodology for arriving at the sales price in such contracts.

Also, we find that Manitoba Hydro continues to improve its contractual documentation to more effectively mitigate the risk exposure from entering into long-term fixed price contracts for the sale of firm energy. On the basis of the policy decisions in place with respect to risk tolerance, Manitoba Hydro quantifies its drought risk appropriately and currently provides for appropriate levels of reserves of risk capital against its projected drought risk.

- In terms of risk governance, we conclude the following:

– Manitoba Hydro's power sales are asset backed. These sales are generally low risk and the Manitoba Hydro risk governance policies and reporting relationships, including the role of the Middle Office, are evolving appropriately.

– The Export Power Middle Office is a single, independent, risk management function. It is steadily progressing in terms of its responsibilities for measuring, monitoring, controlling, and reporting the risks associated with PS&O's opportunity power sales activity.

– The Export Power Middle Office is undertaking an initiative to improve its risk analytics capabilities. It requires further resource(s), supported by risk analytics software that is integrated with Manitoba Hydro's energy transaction management system (WebTrader). The timeliness of this risk monitoring will continue to improve with added analytical resources and related technology.

- With respect to power risk management, we conclude that Manitoba Hydro demonstrates prudent risk management with the following risk management practices:

– Extensive corporate oversight and a deliberate internal review process related to major export contract term sheets;

- Conservative stress testing assumptions and methodology;
- Transaction processing controls consistent with prevailing practices to mitigate human error and operational risk;
- Compliance and risk monitoring performed by an independent middle office; and
- Comprehensive suite of management and performance reports.

  In light of these prudent practices, Manitoba Hydro will continue to strive to keep pace with the dynamic energy markets and will identify opportunities to improve its risk management capabilities. Manitoba Hydro may consider the following recommendations:

- Revise long-term contract policies stipulating Middle Office participation in the internal review process of major export contract term sheets;
- Develop formal identification of all significant risks in policies and procedures;
- Measure market risk exposure for short-term physical positions in its trading portfolio and evaluate the benefits associated with valuing its long-term contracts;
- Consider a probabilistic measure (e.g., Revenue-at-Risk) as an alternative tool to further understand potential drought exposure;
- Develop risk limits commensurate with authorized trading activities and products; and
- Develop risk exposure monitoring reports for compliance purposes.

A key benefit of adopting the above recommendations would be better information to decision makers on the optimal capital structure of Manitoba Hydro. On the basis of reviewing PUB Board Orders and based on information from Manitoba Hydro personnel, there has been considerable attention paid to the company's capital structure. This has led to a policy of targeting a 75:25 debt to equity ratio to help ensure that Manitoba Hydro maintains sufficient equity to act as a buffer against the inherent volatility of its business. As of fiscal 2008/09, primarily through building up its retained earnings to $2.1 billion, Manitoba Hydro has achieved the 75:25 debt to equity ratio target.

Going forward, the adequacy of a 75:25 debt to equity ratio should be regularly reviewed, particularly in light of the substantial capital expansion plans for Manitoba

Hydro's generation and transmission system. Accordingly, the appropriate capital structure for Manitoba Hydro will likely continue to be an ongoing issue for the company, its regulator, its shareholder, ratepayers and lenders.

Our report focused on the Manitoba Hydro's risk management practices specifically in the areas of forecasting models, long-term power sales contracting, risk governance, and power risk management. Overall, in the context of the nature, size and business model of its hydroelectric power operations, we are satisfied that Manitoba Hydro is following sound practices in these areas.

1

1. Introduction

The utility industry has undergone significant change in the last decade, including deregulation in some jurisdictions, the introduction of competitive energy markets across Canada and the United States ("US"), heightened environmental attention, fluctuating economic conditions and a continued focus on security of supply at reasonable prices for ratepayers. Taken together, these factors have significantly added to the complexity of managing risk. Accordingly, Manitoba Hydro ("MH") retained a consultant (the "Consultant") to review specific aspects of certain risk management processes. The Consultant's work led to the generation of a report in December 2006, and later work of the Consultant led to the generation of subsequent reports (collectively, the "Consultant's Reports"; listed in section 1.3.2 of this report).

The Consultant's Reports contain a series of assertions made by the Consultant pertaining to MH's export power sales and associated risk management practices. KPMG LLP ("KPMG") was retained by MH in late 2009 to perform an independent review (the "Review") of its risk management practices in light of the assertions raised by the Consultant. This report describes the Review undertaken by KPMG.

1.1 Scope and Nature of the KPMG Review

KPMG was retained by the Board of Directors of Manitoba Hydro in November 2009 to carry out an independent assessment of risk management practices in the hydroelectric operations and to address the assertions raised by the Consultant.

1.1.1 Scope of the Review

The scope of the Review is as follows:

- review the assertions that have been made by the Consultant and the reports and services provided by the Consultant.
- identify the positions of Manitoba Hydro staff on each of the assertions and the services provided by the Consultant.
- perform a review and validation study of the merits of the Consultant's assertions and services.

- prepare a report summarizing KPMG's findings.

As a consequence of the above, KPMG's review is limited to certain risk management practices of MH stemming from the assertions. Our scope is limited to key aspects of the hydroelectric operations of MH and related corporate functions but does not include reviewing MH's risk management practices as they apply to any other business products such as its natural gas operations, or to areas such as environmental and safety issues.

KPMG has developed this report, which documents the findings of the Review, for use by its client, Manitoba Hydro, but understands and acknowledges that the report may be provided to The Public Utilities Board of Manitoba ("PUB") pursuant to regulatory proceedings related to MH's risk management practices.

1.1.2 Phasing of the Review

KPMG undertook the Review using a two-phased approach.

In Phase 1, KPMG undertook an initial assessment of assertions raised in the Consultant's Reports to identify the scope of the assertions and to develop an approach and work plan for the more detailed assessment that would be undertaken in Phase 2 of the Review. The Phase 1 report was delivered to the Audit Committee on December 4, 2009 and is included in this report as **Appendix B**.

In Phase 2, KPMG undertook the work plan developed during Phase 1.

1.1.3 Reliance on MH Information

In the conduct of the Review, KPMG relied on a range of documentation provided to us by MH personnel as well as discussion with MH management. MH has confirmed to KPMG that:

- The information provided to KPMG was true and correct in all material respects, and did not and does not contain any untrue statement of a material fact in respect of MH and does not omit to state a material fact in respect of MH necessary to make the information not misleading in light of the circumstances under which the information was made or provided;

- MH has reviewed the draft of this report dated March 31, 2010 and has confirmed that it has no information or knowledge not disclosed to us which would reasonably be expected to affect our comments, observations, or conclusions;

- MH has no knowledge of the existence of any other reports in the possession of MH prepared by the Consultant for MH regarding its risk management practices other than those listed in KPMG's report; and

- Since the dates on which the information was provided to KPMG, except as disclosed in writing to KPMG, there has been no material change in the information provided regarding MH and no material change has occurred in the information or any part thereof which would have or which would reasonably be expected to have a material effect on KPMG's Review.

KPMG reserves the right, but is under no obligation, to review or modify our analysis or report in light of any additional information that may become available subsequent to the date of this report.

1.2 Conceptual Framework

In order to help us communicate clearly in this report, KPMG has employed some basic concepts and defined various terms and concepts which are capitalized throughout the report and presented in the glossary which forms **Appendix A** to this report. This Section 1.2 provides a brief overview of key concepts underlying our work.

1.2.1 Issues and Themes

In undertaking the Review, KPMG analyzed the various assertions made by the Consultant in order to group related assertions into Issues and identify those which are outside of our scope.

As described more fully in the Phase 1 report, we define an Issue to be the components of an assertion(s) that reflect an alleged fundamental deficiency in MH. To help organize our approach for the conduct of the Review, KPMG also grouped related Issues (9) into Themes (4) as shown in Exhibit 1-1.

Exhibit 1-1: Themes and Issues

Themes and Issues			
1 Forecasting models			
Issue 1	Appropriateness of inputs and model logic relating to		
		1.1	Pricing
		1.2	Water volume
		1.3	Key model parameters
		1.4	Lake water level balances
		1.5	Market rules.
Issue 2	Treatment of optionality		
		2.1	Plant cycling
		2.2	Storage.
Issue 3	Validation of models		
2 Power sales management			
Issue 4	Pricing methodology for firm power sales		
Issue 5	Risk capital reserves		
Issue 6	Long-term contracts structure.		
3 Risk governance			
Issue 7	Independence of the Middle Office function		
Issue 8	Resourcing and authorities relating to energy risk management.		
4 Power risk management			
Issue 9	Treatment of risk (identification, measurement, treatment)		

The Themes and Issues presented in Exhibit 1-1 represent the structure used for the conduct of Phase 2. Our Phase 1 work contemplated that the version of this structure developed during Phase 1 would be subject to change during Phase 2 and indeed three adjustments were made:

- Theme 4 was renamed from power resource management to power risk management to more accurately reflect the nature of the Issues contained therein.

- For ease of presentation, the theme regarding portfolio monitoring and reporting that was included in the Phase 1 work was merged into Theme 4 and the order of the Themes was changed.

- The issue regarding Power Sales' Requests for Proposals ("RFP") process in Phase 1 was dropped as a separate Issue. It stemmed from assertions by the Consultant regarding the process by which MH places RFP's into the market. During the conduct of Phase 2, KPMG was advised that MH does not issue RFP's to either procure or sell power (and has only responded to one RFP in which the process was established by the issuer of the RFP). Since the premise of the assertions underlying this Issue is incorrect, it was decided to drop this Issue (and deal with that one RFP response as part of our analysis of Theme 1).

These changes are essentially administrative, and do not impact the nature or scope of the work undertaken in Phase 2 of the Review.

In assessing the Issues, we took the approach that our work would not necessarily result in a total concurrence with or rejection of the assertions underlying an Issue; in some instances, we have found that we concur with some elements of an assertion and reject other elements. Accordingly, we would suggest that readers of this report focus on the analysis of the Issues as well as any recommendations that relate to the Issues, rather than focusing on whether we concur with or reject any particular assertion.

In utilizing the approach of grouping related assertions into Issues and then addressing the Issues, our scope in certain instances extends beyond the specific matters addressed by the assertions. In general, we applied this general approach for the following two reasons:

- ***to appropriately address an Issue:*** Our analysis in certain circumstances had to consider the overall context of the matter in question in order to appropriately address an Issue. For example, if an Issue addresses certain aspects of MH's middle office and if the appropriate analysis of that Issue requires examination of selected aspects of both the front office and the back office, we would examine those selected aspects for both the front office and the back office. This general approach is designed to allow us to address the root causes of an Issue rather than just its consequential or symptomatic aspects.

  This general approach has been applied to the analysis of an Issue and also to the development of our recommendations; and

- ***to add value for MH in instances where it was efficient to do so.***

1.2.2 Concept of Risk

As mentioned, KPMG has been retained to perform an independent review of MH's risk management practices. At the core of this review is the concept of risk. For the purposes of our work, we looked to a number of leading international risk management bodies and based our work on the following concept:

Risk is defined as the likelihood and severity of an event or action that will adversely affect the company's ability to achieve its business objectives and execute its strategies successfully.

In general, an organization will apply this concept to fit its particular circumstances and needs. An effective risk management framework assesses risk in terms of its key components, and how they affect the organization. In the context of a hydroelectric utility, key components of overall risk include:

- regulatory risk;
- volume risk (both resource and load);
- market risk;
- credit risk;
- operational risk; and
- financial risk.

1.3 Approach to Phase 2 of the Review

1.3.1 Multiple Lines of Evidence

Phase 2 of the Review examined multiple lines of evidence for consideration, including:

- reviewing MH documentation and data;
- interviewing MH personnel;
- conducting analysis based on industry leading practices;
- conducting research of other electric utilities;
- consulting with specialized subconsultants;
- conducting literature reviews;
- analyzing third party data and reports;

- analyzing various financial and forecasting models used by MH; and
- analyzing model runs conducted by MH at KPMG's direction.

See **Appendix C** for a listing of the documentation provided to us by MH.

Additionally, KPMG reviewed the Consultant's Reports not considered in Phase 1 and other documents to help ensure that no new Issues and Themes should be considered.

1.3.2 Review of Consultant's Reports

As mentioned previously, KPMG conducted a comprehensive review and analysis of the assertions made by the Consultant in the Consultant's Reports, which are listed below:

- "Manitoba Hydro Risk Review 0708", dated December 4, 2006 (42 pages);
- "Risk Management Response", dated January 2008 (204 pages);
- "Top 20 Risk Management Issues", dated June 6, 2008 (40 pages);
- "Long Term Contracts Risk Report", dated October 2008 (45 pages); and
- "Long Term Contracts Executive Summary Middle Office Objectives – Action Plans", dated November 5, 2008 (18 pages);

For all but the "Top 20 Risk Management Issues", KPMG went through them line by line and allocated each sentence into Themes and Issues[1] or into a grouping indicating that the sentence was outside of our scope.[2] The results of this process are presented in **Appendix D**.

1.3.3 Communications with the Consultant

In Phase 1 we contemplated communicating with the Consultant to potentially improve our understanding of the assertions raised by the Consultant. We nonetheless anticipated that we could face challenges to being able to arrange any such communication and to incorporating it in a timely manner, and proceeded as though

[1] *Using the structure of Themes and Issues from Phase 1 as outlined in Section 1.2.1.*

[2] *This process was not conducted for the "Top 20 Risk Management Issues" report because it represented the key issues of information that had been presented in previous reports. As mentioned, this report was reviewed as part of our Review.*

we would need to develop our own evidence path independent of any communication with the Consultant.

During the conduct of Phase 2, we made the decision not to approach the Consultant to initiate such communication. Shortly after the commencement of our Phase 2 work, the Consultant wrote to KPMG asking that the firm "cease and desist" any use of materials prepared by the Consultant which have been provided to KPMG by MH in connection with a complaint which has been filed under the Public Interest Disclosure (Whistleblower Protection) Act. In particular, in the Consultant's "cease and desist" letter, the Consultant wrote that "it would be inappropriate for me to transfer and explain any materials …directly to KPMG", for KPMG "to stop use of and to not received any materials prepared by my firm that you may be in possession of" and "to return such materials promptly to Manitoba Hydro and make no further use of them", and that "release of my reports, findings and any materials involve a breach of contract between myself and Manitoba Hydro and would place KPMG also liable for using inappropriately disclosed materials". Further, the Consultant stated that it "would be serving an injunction against all parties for any violations of our confidential information."

Subsequently, MH commenced a legal proceeding between the Consultant and itself in order to be in a position to release our Phase 2 report.

Accordingly, after considering the above – especially the fact that the Consultant explicitly indicated in the "cease and desist" letter that it would be inappropriate for it to explain any of its materials to KPMG – and considering that we, after having already completed a detailed review of the Consultant's Reports and other documents, were confident that we understood sufficiently the assertions made by the Consultant to be able to carry out a high quality review, we made the decision not to initiate communication with the Consultant.

1.3.4 Time Frame of the Assertions and Impact on This Review

The Consultant Reports contain assertions regarding MH's risk management practices over a relatively discrete time period (i.e., primarily 2006 but with some reference to past practices in some previous years). In this Review, KPMG considers the evolution of certain MH risk management practices both at the time when the Consultant's assertions were made, as well as MH current and evolving risk management practices.

The approach that we have undertaken in conducting our Review has been to focus on an *ex ante* rather than an *ex post* analysis – i.e., looking at appropriateness of the processes that were utilized at the time a decision was made rather than whether a decision turned out after the fact to be a good decision or not.

Further, during the conduct of the Review, we were aware that various initiatives were ongoing within MH regarding its risk management processes. Depending on when it is read, this report may not necessarily reflect MH's most current risk management practices in all respects, but believe that we have reasonably captured MH's circumstances as of the first quarter of calendar 2010. Further, as mentioned above, MH has represented to us that there has been no material change in the information provided regarding MH which would have or which would reasonably be expected to have a material effect on our Review.

1.3.5 Case Studies of Other Power Utilities

KPMG conducted a series of case studies about other electric utilities to provide additional context for the conduct of our work. The purpose of the case studies was to obtain current industry comparables and review how other utilities have adjusted and implemented strategies to adapt to changing market conditions.

Electric utilities were identified from KPMG's knowledge, input from MH, and industry research Selection criteria included:

- considerable hydro power generation;
- government-ownership;
- participation in power markets;
- geographic relevance;
- comparable size; and
- relevance to at least one of the Themes being addressed.

The focus was North America, reviewing key Canadian electric utilities and a geographic mix of U.S. utilities as well as some international utilities that met at least some of the selection criteria. In total, 14 utilities were reviewed, five in Canada, seven in the United States, one in South America and one in New Zealand.

The information collected on each utility included publicly available data, regulatory filings and direct interviews with an appropriate representative(s). General background information on each utility was collected in order to understand the context in which the utility company operates.

In addition to contextual information, the questions posed to these utilities were based on the Themes being addressed by KPMG.

Further details regarding the case studies are available in **Appendix E**.

1.3.6 Use of Subconsultants

KPMG engaged National Economic Research Associates, Inc. ("NERA") and CDDHoward Consulting Ltd. ("CDDHoward") as subconsultants to supplement KPMG's expertise in specific technical matters.

The scope of NERA's work included commenting on:

- certain economic matters relevant to MH's planning practices;
- principles of risk management as applied to power export sales;
- business strategy for expansion and export contracts;
- the terms and conditions of export power contracts;
- sufficiency of long-term contract prices;
- methodologies to measure risk capital and its applicability to MH; and
- weather derivatives.

The scope of CDDHoward's work included commenting on:

- hydrologic forecasting; and
- model production coefficients.

1.4 Organization of Phase 2 Report

The remainder of this report is structured as follows:

- Chapter 2 provides a brief overview of Manitoba Hydro, its mandate, electricity operations, financial and operating results, and capital structure in order to establish context for subsequent chapters.
- Chapters 3 to 6 each provide the results of the analysis of the separate Themes by:
  - providing background information on the Theme and its Issue(s);
  - outlining the scope of the analysis of the Theme;
  - documenting the approach and methodology used for the analysis of that Theme;
  - presenting the results of the analysis for that Theme; and
  - outlining the findings and conclusions as well as offering recommendations.

Specifically:

- Chapter 3 (Forecasting Models) examines key issues related to certain models used by Manitoba Hydro for supporting operation decisions and financial forecasting and budgeting.
- Chapter 4 (Power Sales Management) examines key issues associated with Manitoba Hydro's practice of entering into long-term fixed price contracts for export power sales.
- Chapter 5 (Risk Governance) examines risk governance practices at Manitoba Hydro.
- Chapter 6 (Power Risk Management) examines key issues associated with Manitoba Hydro's power risk management practices.

Certain topics (e.g., drought risk) are, by necessity, dealt with in more than one chapter. Doing so was necessary when a particular topic falls within the scope covered by more than one Theme in order that the Phase 2 results are presented in a structured and logical manner. Chapter 7 provides a brief Conclusion that integrates the summary conclusions of the previous chapters of the report.

2

2. Overview of Manitoba Hydro

To provide context for the detailed analysis which follows in subsequent chapters, this chapter provides a high level overview of MH, outlining its history, legislation and mandate, electric operations, financial and operating results, and capital structure.

2.1 Historical Overview and Legislative Mandate

During the first half of the 1900's, various companies in Manitoba developed hydroelectric generating stations, transmission and distribution systems to serve their existing and projected future needs. This led to the development of a decentralized system that suffered from lack of coordination. As a result in 1949, the *Manitoba Hydro-Electric Board Development Act* (the "MHEBDA") was passed by the provincial legislature "to provide for the continuance of a supply of power adequate for the needs of the province, and to promote economy and efficiency in the generation, distribution and supply of power". The MHEBDA was a major initiative to help consolidate and modernize Manitoba's power generation and distribution, an initiative which culminated with the passing of the *Manitoba Hydro Act* (the "MHA") on April 1, 1961. Under the MHA, Manitoba Hydro, a Crown Corporation, became solely responsible for the provision of electrical services in the province, except for the central portion of the City of Winnipeg which was served by Winnipeg Hydro until its acquisition by MH in 2002.

According to Section 2 of the *Manitoba Hydro Act, C.C.S.M. c. H190*, the Mandate of MH is to:

> *"provide for the continuance of a supply of power adequate for the needs of the province, and to engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power and, in addition, are:*
>
> *(a) to provide and market products, services and expertise related to the development, generation, transmission, distribution, supply and end-use of power, within and outside the province; and*

(b) *to market and supply power to persons outside the province on terms and conditions acceptable to the board."*

Key aspects of this Mandate are:

- It provides a focus on the continuance of a supply of power adequate for the needs of the province;
- It requires MH to promote economy and efficiency in its activities; and
- It contemplates exporting of power to users outside the province.

Given the economics of power generation facilities and the need to plan for future demand, MH has built, and expects to continue to build new hydro generation and transmission facilities to provide capacity beyond immediate need in the province. This excess energy can then marketed outside the province. A detailed analysis of the strategies used by MH in this regard is contained in Chapter 4.

According to its terms of reference, the Board of Directors "*is charged with the responsibility to carry out the duties, powers and functions of MH as set out in The Manitoba Hydro Act. The corporation is charged with responsibilities which include, ensuring a safe, reliable and economical supply of energy for Manitoba. The corporation operates in an environmentally responsible manner, consistent with the principles of sustainable development. It earns revenues to keep rates low for Manitobans through the export of power and the provision of energy-related services. The Board has the statutory authority and obligation to oversee the management of the business and affairs of the Corporation and to ensure that the Corporation fulfils its statutory objectives in the public interest.*"

2.2 Overview of Electricity Operations

MH's electricity generation is virtually all from renewable hydro power. MH has 14 hydroelectric generating stations on the Nelson, Winnipeg, Saskatchewan and Laurie rivers that represent over 5,000 MW of MH's 5,490 MW of net capability.

These hydroelectric generating stations account for about 98% of the company's total power produced annually. The remaining amount of the company's total production is generated by two thermal generating stations (Brandon and Selkirk) and four remote diesel generating stations. Power is also purchased from an independent wind farm (*Manitoba Hydro 2009 Annual Report*, p.2).

In the mid-1960s, provincial power planners made a fundamental long-term decision on the future supply of electricity for Manitoba, which led to the construction of three major generating stations along the lower Nelson River, and a high voltage direct current (HVDC) transmission system to carry electricity to southern centres. Nearly 80 percent of Manitoba's electricity is produced by the major generating stations on the Nelson River. Lake Winnipeg Regulation, completed in 1976, enabled Lake Winnipeg to be regulated within certain limits allowing greater flows into the Nelson River when needed. The Churchill River Diversion, completed in 1977, redirects most of the flow of the Churchill River at Southern Indian Lake eventually through the generating stations on the lower Nelson River. The diversion increases the power producing potential of the lower Nelson River by as much as 40 percent.

MH is a significant exporter of electricity, and approximately one-third of electricity produced is exported annually. The term "export" refers to power sales outside of the province of Manitoba, i.e., extraprovincial sales and exports are used interchangeably. The United States has been and continues to be MH's primary export market. In fiscal 2008/09, MH revenues from electricity sales to the United States were $491 million, representing 79% of MH's extraprovincial revenues (*Manitoba Hydro 2009 Annual Report, p.72*). United States sales typically represent over 80% of MH's exports. Manitoba and U.S. utilities have traded electricity since transmission lines first linked Manitoba and the United States nearly 40 years ago. MH has transmission lines connecting with Minnesota, North Dakota, Ontario and Saskatchewan.

Currently, there are nine formal long-term export trade agreements with six US electric utilities and many short-term agreements with electric utilities and marketers in the mid-western US, Ontario and Saskatchewan/Alberta. With the Midwest Independent Transmission System Operator (MISO) market launch in 2005, MH buys and sells energy in one of the largest electricity markets in North America.

2.3 Financial and Operational Overview

The following table (Exhibit 2-1) provides an overview of select financial and operational statistics over the past ten fiscal years from MH. Revenues have shown relatively steady and modest growth since 2004 (except for a decline in fiscal 2006/07). Net income has fluctuated significantly over the past ten years. In the past two fiscal years, net income was $298 million in 2008/09 and $346 million in 2007/08, significantly increasing the corporation's retained earnings and equity ratio. The impacts of the 2002-2004 drought period adversely impacted extraprovincial sales and net income, particularly in 2002/03 and 2003/04. System capacity has remained virtually unchanged since 2003. System generation loads, system demand, and peak demand have experienced modest growth over most of the past ten years.

Exhibit 2-1: Select Manitoba Hydro Financial and Operational Statistics

Manitoba Hydro 10-Year Financial and Operational Overview										
Fiscal year ended March 31st,	**2009**	**2008**	**2007**	**2006**	**2005**	**2004**	**2003**	**2002**	**2001**	**2000**
Financial Statistics										
Total Revenue ($millions)	2,364	2,250	2,140	2,345	2,017	1,781	1,869	1,864	1,773	1,391
Domestic Electrical Revenues ($millions)	1,161	1,097	1,040	1,001	954	936	891	797	789	746
Extraprovincial Electrical Revenues ($millions)	623	625	592	827	554	351	463	588	480	376
Net income ($millions)	298	346	122	415	136	(436)	71	214	270	152
Total Assets ($millions)	12,341	11,766	10,922	10,482	9,952	9,903	10,234	10,405	9,966	8,692
Long-term debt ($millions)	7,661	7,218	6,822	7,051	7,048	7,114	6,925	7,123	6,968	6,611
Retained earnings ($millions)	2,120	1,822	1,407	1,285	870	734	1,170	1,302	1,088	818
Contributions in Aid of Construction ($millions)	296	300	298	297	296	274	264	281	281	275
Interest Coverage[1]	1.58	1.69	1.23	1.77	1.25	0.17	1.14	1.42	1.62	1.35
Equity Ratio[2]	0.25	0.24	0.20	0.19	0.15	0.13	0.20	0.23	0.20	0.17
Capital Coverage[3]	1.81	1.62	1.10	2.28	1.20	(0.32)	1.10	1.67	1.18	1.28
Operating Statistics										
System Capability (000 kW)	5,480	5,465	5,461	5,469	5,470	5,471	5,464	5,230	5,210	5,116
Manitoba Firm Peak Demand (000 kW)	4,477	4,273	4,184	4,054	4,169	3,959	3,916	3,760	3,637	3,524
Total Energy Supplied (000 000 kWh)	34,541	35,366	32,144	37,632	31,559	19,349	29,178	32,643	32,697	30,155
Load at Generation (000 000 kWh)	24,298	23,997	23,339	22,634	22,463	21,918	21,976	20,629	20,133	19,110
System Demand (000 000 kWh)	21,266	21,109	20,555	19,976	19,781	19,323	18,953	16,958	16,698	15,820
Net Metered Interchange (Exports-Imports)	9,589	10,590	8,217	13,706	8,213	(2,578)	6,378	10,911	11,247	9,906
Number of Electric Customers	527,472	521,599	516,861	509,791	505,666	501,650	497,725	405,535	403,040	402,023

1 Interest Coverage represents net income plus interest on debt divided by interest on debt.
2 Equity ratio represents equity (retained earnings plus contributions in aid of construction) divided by equity plus debt (long-term debt plus notes payable minus temporary investments).
3 Capital Coverage represents internally generated funds divided by capital construction expenditures.
Source: Manitoba Hydro 2009 Annual Report

2.3.1 Background Information on MH's Capital Structure

This discussion provides an important context on the relationship of risk and capital structure, as MH's capital structure has been an ongoing issue at MH and the Public Utilities Board over many years. In this section, we summarize some of the background considerations that address MH's capital structure.

Capital intensive industries such as electric utilities typically use greater leverage and have relatively high debt to equity ratios compared to most industries. In particular, a regulated utility with significant tangible assets and stable, relatively predictable future earnings will tend to use more debt financing and can take on higher debt than most companies in other industries. The more debt it can take on in its capital structure, the lower the overall cost of capital as the cost of debt is lower than the cost of equity. A regulated utility tries to balance its capital structure and mix of debt and equity with the needs of its shareholders, ratepayers and bondholders. For utilities, equity, through retained earnings, provides confidence to financial markets and aids in securing financing at attractive interest rates, and provides increased assurance of future rate stability and a cushion against risk.

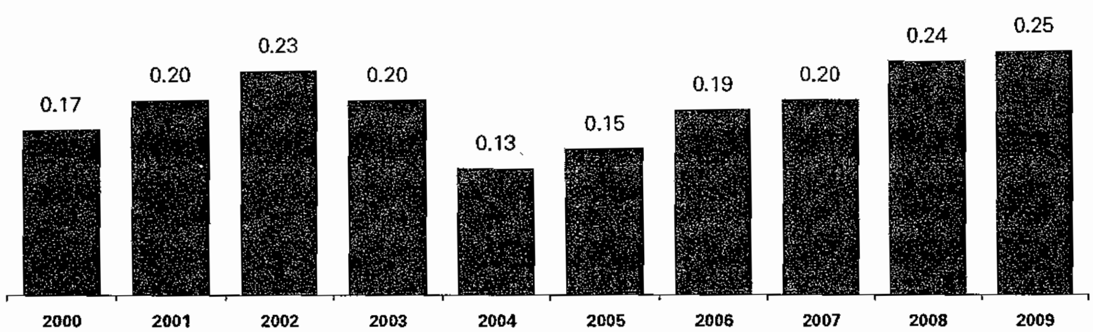
As evidenced in its most recent annual report, MH currently has established a minimum target equity ratio of 25% (or a debt to equity ratio of 75:25):

"Manitoba Hydro manages its capital structure to ensure sufficient equity to enable the Corporation to absorb the financial effects of adverse circumstances and to ensure continued access to stable low-cost funding for the Corporation's capital projects and its ongoing operational requirements. The Corporation monitors its capital structure on the basis of its equity ratio. Manitoba Hydro's current target is to maintain a minimum equity ratio of 25%" (*Manitoba Hydro 2009 Annual Report, p.114*).

Noteworthy is that MH's long-term debt is guaranteed by the Government of Manitoba (with the exception of $77 million in bonds issued for mitigation projects) (*Manitoba Hydro Consolidated Financial Statements for the year ending March 31, 2009, Note 11*).

As indicated in Exhibit 2-2 which shows equity ratios over the past decade, MH has significantly increased its equity ratio in recent fiscal years, eventually meeting its target in 2008/09.

Exhibit 2-2: MH Equity Ratios 2000 - 2009



Source: Manitoba Hydro 2009 Annual Report

Note: Equity ratio represents equity (retained earnings plus contributions in aid of construction) divided by equity plus debt (long-term debt plus notes minus temporary investments).

The capital structure of MH has been a long standing issue that has drawn much attention in the regulatory hearings of the Public Utilities Board of Manitoba.

In September 1995, MH adopted a target to achieve and maintain a minimum debt to equity ratio of 75:25 by no later than 2006. In 1996, MH had a debt to equity ratio of 91:09, but managed to reduce it to 80:20 in 2001. In the PUB's Board Order 7/03, February 3, 2003 (p.13) it was noted that MH stated that the current target would not be attainable.

In the PUB Board Order 101/04, July 28, 2004 (p.15), it was noted that the 2002-2004 drought made it more difficult to achieve Manitoba's debt to equity target and the loss associated with the drought pushed back the date of realizing a 75:25 debt to equity ratio by several years.

As mentioned above, the drought of 2002-04 had a significant impact on MH's ability to achieve its targeted debt to equity ratio. In the context of MH's hydro-based system, drought risk is clearly a key operational risk of the company. In the PUB Board Order 7/03 under "Risks" (p.88), the PUB's view was that a five-year drought represents the greatest threat to MH's financial position. PUB Board Order 7/03 (p.88) noted that MH's net revenues are subject to vagaries of weather and water flows and establishing an adequate [retained earnings] reserve level is an appropriate strategy to mitigate the financial impact of a drought.

As a hydro-based system, drought periods have a significant adverse impact on power sales through reduced exports and consequently on net income. Conversely, high water flow periods contribute to more surplus power and export sales and higher net income and retained earnings.

MH has identified and quantified its major risks, which includes drought risk (*Source: Manitoba Hydro 2009 Annual Report, p.81*).

The financial effects of a drought were evidenced by the 2002-2004 drought, where the effects were first felt in 2002/03 in reduced net income, and more fully realized in 2003/04 with MH incurring a loss of $436 million. The drought resulted in MH's decision to import power and led to reduced export sales in order to ensure that the needs of its domestic market were met, and both factors led to the financial loss.

Prior to the drought, MH had built up its retained earnings to $1.3 billion in 2001/02. This equity provided a buffer for the financial impacts of the drought experienced in 2002/03 and 2003/04. Without sufficient equity, MH would have had to turn to the Government of Manitoba as its shareholder and/or its ratepayers to cover the large loss in 2003/04.

In 2004, the PUB further outlined its view on MH's debt to equity financial target.

"Achieving a debt:equity level of 75:25 would provide increased rate stability benefits, and hold down financial charges. The 75:25 benchmark represents a modest target, one comparable with the current debt:equity ratios of similar Crown hydroelectric utilities in other Canadian provinces (B.C. Hydro and Hydro Quebec). In summary, meeting this target within a reasonable period of time would reduce long-term pressure on domestic electricity rates, better assure bondholders and thus constrain financial charges and provide a hedge against a future drought." (*PUB, Board Order 101/04, July 28, 2004, p.31*)

Subsequent PUB Board Orders (2004 through 2008) reiterated the PUB's concern about MH's overall debt level and the need to achieve the debt to equity target of 75:25 as quickly as possible. In these orders, the PUB Board called for faster progress towards the 75:25 debt to equity target. This has been one of the primary drivers of MH rate increases in recent years.

"The Board notes the reported improvement in Manitoba Hydro's actual and forecast debt:equity ratio, and understands the improvement is largely attributable to two factors, the rate increases approved by the Board and recent favourable river flows bringing additional export revenues." (*PUB Board Order 32/09, March 30, 2009, p.14*).

In fiscal 2008/09, primarily through building up its retained earnings to $2.1 billion, Manitoba Hydro achieved the 75:25 debt to equity ratio target.

While MH has met its debt to equity ratio target, a deterioration of that ratio is expected with the planned debt financing of the construction of new generation and transmission projects (*PUB Board Order 32/09, p.31*).

In summary, the level of equity and debt to equity ratio provides an important context for a review of risk issues. On the basis of reviewing PUB Board Orders presented above and based on information from MH personnel, MH operates under a policy of maintaining sufficient equity and it does so to promote stability by providing an equity cushion against inherent volatility of the business, in particular MH's exposure to periods of drought. While it is very difficult to peg a single optimal capital structure for any corporation, the appropriate balance and mix of debt and equity has, and will likely continue to be, an ongoing issue for MH, its regulator, its shareholder, ratepayers and lenders.

3

3. Forecasting Models

In this Chapter, we address various issues related to three models used by Manitoba Hydro for supporting operations, capacity planning, and financial forecasting and budgeting processes. As described in Chapter 1 of this report, the issues we have identified are based on various assertions raised by the Consultant. In the Consultant's report, there were various assertions related to the deficiencies in the models used by MH, specifically the HERMES (Hydro Electric Resource Management Evaluation System), SPLASH (Simulation Program for Long Term Analysis of System Hydraulics), and PRISM (Power Risk System Model) models.[3]

This Chapter is organized under the following headings:

- 3.1 Scope of our Review
- 3.2 Key Findings
- 3.3 Approach and Methodology
- 3.4 Overview Models
- 3.5 Review of HERMES – Model Validity
- 3.6 Review of HERMES – Model Operations
- 3.7 Review of HERMES – Model Assumptions and Data
- 3.8 Review of HERMES – Sensitivity Analysis on Price Inputs
- 3.9 Review of HERMES - Conclusion and Recommendations
- 3.10 Review of SPLASH
- 3.11 Review of PRISM
- 3.12 Review of the Issue of Multiple Models
- 3.13 Conclusion.

3.1 Scope of Our Review

In Phase 1 of the review as shown on Exhibit 1-1, KPMG identified three Issues within the Theme of Forecasting Models. The three Issues and along with a summary of the Consultant assertions of each Issue are as outlined below.

[3] *For ease of reference, we have referred to HERMES as a model although MH considers it to be a decision support system that includes a number of individual models and analytical tools.*

- Issue 1 – Appropriateness of inputs and model logic relating to:

  – Pricing and market rules

The Consultant asserts that the HERMES model does not incorporate current market prices and that it needs to do so in order to serve as an appropriate basis for decisions made to release water. Specifically, the Consultant asserts that the prices used in the HERMES model should be updated regularly to reflect today's broker quotes and a true market environment. The Consultant asserts that not doing so prevents MH from optimizing its financial performance in selling surplus power or buying hedges as these relate to decisions made to release water. The Consultant also asserted that the prices used in the Generation Estimate report and those used in the HERMES runs are inconsistent. It further noted that this exposes MH to pricing error risks.

  – Water volume

The Consultant asserts that MH's models sub-optimize the treatment of water volumes. Specifically, the Consultant recommends improvements to MH's method of antecedent flow forecasting (e.g., use of backtesting to validate the antecedent forecasting methodology). The Consultant also has concerns about the validity of using historical water flow data in the models. The Consultant identifies a number of years which mark the addition of gauging points and hence improvements in the quality of water data. As a consequence, the Consultant suggests that water flow data from prior to 1942 are unreliable.

  – Key model parameters

The Consultant asserts that the SPLASH and HERMES models utilize different sets of internal model parameters (production coefficients) for the conversion of water flow to power at each hydro plant. The Consultant further noted issues regarding some approximations in the HERMES model as well as the use of "model adjustment factors" (which are sometimes manually changed). The Consultant recommended that MH undertake on-going calibration and updates to both of these models.

  – Lake water level balances

The Consultant notes that the SPLASH model assumes "perfect foresight" of water flows and hence assumes lake ending levels which in the real world are impossible to attain. This raises concerns with respect to the calculation of the costs of a drought. Also, the Consultant raised concerns about the reconciliation of lake level balances in the financial forecasting process.

- Issue 2 – Treatment of optionality related to plant cycling and storage

The Consultant notes a variety of deficiencies in the modeling of storage optionality, which is the financial value associated with the flexibility to change storage levels in a hydroelectric system. As a result, the Consultant asserts that MH does not effectively capture or optimize the value of hydroelectric storage. In particular, the Consultant alleges a variety of deficiencies with respect to the modeling of storage in HERMES. The Consultant identifies, among other issues, differences between the HERMES and SPLASH models in their decision making with respect to the use of water in storage and in identifying target ending reservoir levels.

- Issue 3 – Validation of models

Forecasts from models, such as HERMES and SPLASH, are based on inputs and model logic (i.e., the formulas and computational methods embedded in the model). Forecasts generated from models could conceivably be inaccurate either because of flaws in the model logic or errors in the inputs to the model (which are typically forecasts themselves).

Backtesting is a means by which errors in the inputs can be removed in order to verify the appropriateness of the model logic. The Consultant asserts that MH does not back test its HERMES or SPLASH models. Accordingly, the Consultant argues that management decisions and reports based on the outputs of these two models may be flawed.

In order to address the Issues identified in Chapter 1, we have conducted a detailed review of the HERMES models. We have also conducted a high level review of the SPLASH and PRISM models. Our approach in this report is to address the Issues covering the specific assertions of the Consultant. However, given the technical nature of the modeling issues, we have provided direct responses for certain Consultant's assertions relevant to an Issue.

We did not undertake an audit of the models or verify their computational accuracy. Rather, we assessed the overall reasonableness of the modeling approach, taking into account the use of the models, input assumptions, and evidence with respect to the models' effectiveness for their intended role.

We focused on HERMES because it was the subject of the largest number of assertions by the Consultant. Of the three systems reviewed, HERMES also plays the most important role in determining plant production schedules and the amounts of power available for export transactions in the near term (i.e., over the next several months). HERMES is therefore a key tool for managing the risks of energy shortfalls in the near term and the risks associated with transactions in the MISO power market.

Although we focused on HERMES, SPLASH is the key tool used to evaluate the benefits and costs associated with long-term firm sales contracts and new capacity additions. It is also used to estimate the cost of drought events. In examining SPLASH, we therefore examined issues related to its calculation of the amount of Dependable Energy available to support long-term contracts and Manitoba load and its approach to calculating the costs of drought.

3.2 Key Findings

This section outlines our key findings with respect to forecasting models.

On pricing assumptions and market rules, we find the following:

- We have had extensive discussions with MH staff on their approach for incorporating pricing and market rules for power purchases and sales into their planning models. We found that they apply appropriate care and due diligence in this process.
- In incorporating market price inputs, MH needs to account for the various factors that will influence the prices that it will actually receive. We have found that MH puts significant analytical effort into assessing these factors and accounting for them in its modeling approach. Furthermore, the analysis of price patterns is updated as new market data is accumulated over time.
- KPMG has examined the Consultant's assertions regarding inconsistencies between the Generation Estimate report and HERMES and we conclude that, based on the sample of cases reviewed, the quoted data inconsistencies arise out of a misinterpretation by the Consultant of the data that were being presented.
- At KPMG's request, MH undertook a number of special runs of the HERMES model. These runs indicate that inefficiencies in operating schedules that could potentially result from stale or inaccurate price inputs are likely to have only a limited impact on the financial results achieved. Variation in water flow has a much larger influence on optimal schedules (and on MH's financial returns). Constraints on import and export transactions, and the primary need to meet domestic loads, also have significant influence on production schedules.

With respect to flow forecasting and historical water flow data, we find the following:

- MH's process for antecedent forecasting of water flows is reasonable. Underlying relationships used in this process are statistically significant. Moreover, linear regression, which is the basis of MH's antecedent approach, has been a standard industry approach to seasonal stream flow forecasting for many years.

- For general forecasting and planning purposes, it is reasonable to rely on historical water flow data as model inputs. We found a number of other North American hydroelectric utilities that use a similar practice.

- Given the uncertainty of impacts from climate change, MH may wish to formally examine the potential impact of changes in water flows from the historical pattern. Further, it may also wish to undertake scenario analyses to assess the financial impact of droughts worse than the historical record.

  This type of scenario analyses can be used for the purpose of risk analysis, and does not necessarily need to be used as the basis of financial forecasts or for the determination of dependable energy. MH's current approach to forecasting and to calculating dependable energy is reasonable and consistent with practices at other utilities.

- With respect to the Consultant's assertion that the water flow data prior to 1942 are unreliable, we found that the period prior to 1942 is characterized by lower estimated water flows relative to the full period. Hence, forecast production would be higher if these data were excluded from the water flow records. Including data from this earlier period adds an element of conservatism to MH's financial forecasting process.

With respect to the various matters raised by the Consultant regarding key model parameters, we find the following:

- We are satisfied that MH has taken appropriate care and due diligence in modeling production coefficients in its modeling tools. Further, MH carefully takes into account plant efficiency when optimizing the scheduling of its hydroelectric stations.

- We are satisfied that MH has taken appropriate care and due diligence in developing, operating and maintaining the models. This relates to the approximations in the HERMES models, the use of adjustment factors, and the on-going calibration and updates to both SPLASH and HERMES. In the main report, we present recommendations for MH to improve its maintenance of the models.

With respect to lake water level balances, we found the following:

- SPLASH is used for long-term forecasting purposes and to estimate the financial impacts to MH of drought.

- There are a variety of factors that complicate the calculation of drought costs. On one hand, SPLASH is based on "perfect foresight" and will assume that energy stored in reservoirs is used to the fullest extent possible. In practice, MH management will operate the system more conservatively than assumed by SPLASH. In doing so, MH management will maintain reservoir levels at higher levels in order to address the fact that a drought may last longer than the historical record assumed within SPLASH. This may lead to higher actual operating costs in the period of the drought than calculated by SPLASH. Higher costs are the result of scheduling additional imports and fossil fuel purchases (i.e., costs associated with not releasing water from storage at what might appear to be optimal times).

  On the other hand, SPLASH may overestimate fossil fuel costs because it ignores the potential to import power on a non-firm basis. SPLASH assumes that imports only occur under MH's Diversity Contracts, which are considered firm. The ability to schedule opportunity purchases through the spot market and from short-term contracts, thereby reducing fuel purchases, is not considered in SPLASH. In part, higher actual costs in the period of the drought as a result of conservative reservoir management just reflect the movement of costs for reservoir replenishment forward from future periods. However, there may also be opportunity costs associated with the increased risk of water spillage, in the event that water flows after the drought are very high.

- The impacts of these various factors on estimates of drought costs could be separately quantified by MH staff in order to improve stakeholders' understanding of their implications. If a material result is identified, this can then be better communicated to users of the financial information.

- To address specific concerns of the Consultant about the reconciliation of lake level balances within HERMES, we also conducted an analysis of the financial impact of lake level discrepancies observed in the 2006 Generation Estimate Report ("lost water"). There were discrepancies in lake levels on eight of the 29 lakes modeled although the discrepancies were generally small. By applying factors representing the change in water storage with lake levels, the amount of energy per unit of water stored, and the market price of power, we estimate that projected revenues post-2006/07 were understated by about $0.98 million, because of "lost water". The amount of the discrepancy was small (less than 0.2 percent) of total water in storage.

- We checked for similar discrepancies in the Generation Estimate reports supporting Integrated Financial Forecast ("IFF") processes for subsequent years. As at April 1st, 2008, discrepancies were even smaller than in 2007. At an estimated 2,800 MWh, the discrepancy had an estimated financial value of $140,000. The discrepancy at April 1st, 2009 was negligible. Such discrepancies, in addition to being small, have been significantly reduced over time.

With respect to storage optionality and target lake ending levels, we find the following:

- Both HERMES and SPLASH use linear programming routines to identify optimal production decisions under input scenarios that specify loads and water resources, in addition to other production variables, over a planning horizon. Neither HERMES nor SPLASH explicitly address uncertainties in input variables during their optimization routines. As such, neither model identifies the "option value" of storage. Rather, the models incorporate the value of storage under expected conditions in determining optimal production decisions. It is not necessary for the models to identify an explicit "storage option value" for the purpose of production scheduling.

  The HERMES system is used in the planning of operations over a short-term horizon, while SPLASH is used over a longer-term horizon to plan facility additions. Because HERMES is used to support current operational decisions, it has more detail with respect to system operations, and produces financial forecasts that more accurately reflect the realizable value of storage.

- Relative to SPLASH, the HERMES optimization approach provides for more explicit consideration in the production scheduling decisions of the economic value, relative to current sales, of greater or lesser ending storage levels. This seems appropriate given that HERMES is the tool that has the greatest impact on actual operations in the near term. Decisions in the near term, as supported by HERMES, can respond to prices that are currently observed in the market. As a longer-term tool, SPLASH has less need to adjust decisions based on current market data. Rather, it simply needs to capture the "average" or expected economics of a particular decision or sequence.

In summary, we note that neither HERMES nor SPLASH were designed to be financial trading models or to provide estimates of the market value of storage. Both HERMES and SPLASH are water management models designed to meet Manitoba Hydro's operational needs in serving its firm load.

With respect to the validation of the HERMES and SPLASH models, we find the following:

- HERMES is the main tool used to support operations scheduling. Modules within HERMES represent the MH system in a significant amount of detail. These modules have been developed and regularly updated over many years and reflect extensive work to calibrate model outputs to actual system performance and thereby continually validate the model.

- SPLASH is a simulation tool designed to support MH's long-range system planning. The output from the SPLASH model provides information used to evaluate the economics of power resource options such as power export marketing contracts, system enhancements and surplus energy rate programs. SPLASH is also used to support financial forecasting. Similar to HERMES, SPLASH personnel validate the model by performing quality control checks with respect to actual system performance.

- In addition to the current validation procedures used for HERMES and SPLASH, MH should consider incorporating backtesting practices to validate its models. We found no evidence that that there are any material errors or flaws in the management reports generated by using these two models.

- Given ongoing evolution in modeling, MH should continue to examine potential alternative approaches to production and system planning. Consistent with this recommendation, MH's plans for model development indicate that it is continuing to enhance the system over time. Formal peer review or benchmarking exercises might also help ensure that MH benefits from experience gained elsewhere.

- MH has developed its models in-house and thus has relied heavily on the internal expertise of a small group of skilled, experienced staff who are interested in improving the performance of the decision-support tools on an ongoing basis. A significant amount of their expertise is derived from on-the-job training and experience gained in using the models in a "live" environment. This creates some risks with respect to knowledge sharing and corporate exposure to the potential departure of key personnel.

- KPMG recommends that MH develop more formal model documentation. Such documentation will reduce risks associated with the departure of key modeling personnel and it will help internal and external stakeholders better understand and accept model structure and logic. The development of documentation will require additional resources.

3.3 Approach to Our Review

In light of the number and breadth of the Consultant's assertions, KPMG attempted to first gain a broad understanding of the key models used by Power Sales and Operations ("PS&O") for planning and operating purposes. This included MH's approach to operating the models, its framework for quality control and risk management, and strategies for updating the models over time.

The three models that were the focus of our examination are:

- HERMES
- SPLASH
- PRISM

Descriptions of these models are provided in Section 3.4.1.

To support our review, KPMG undertook the following tasks over the course of our engagement:

- We had numerous meetings with MH staff responsible for development and operation of the models.

- We reviewed documentation with respect to these models, including sample outputs.

- We posed questions to MH staff, leading to their formal responses on specific issues.

- We performed our own calculations to assess estimates made by the Consultant.

- We sought input from an independent consulting engineer with expertise in hydrological modeling and optimization of hydroelectric dams.

A key element of our work involved gaining a good understanding of the MH system, including its operating constraints and key value drivers. This background work helped to set the context for assessing model issues.

In conducting our review, we have considered a number of general factors:

- Various assumptions appear to have been made by the Consultant on how the results of the models are used. The Consultant appears to have assumed that the forecasts produced by the models are directly used by MH in operation and power trading decisions without further judgment and/or oversight applied. Some of the Consultant's assumptions are incorrect and as a result the implications identified are not meaningful.

- Many of the risk numbers or metrics identified by the Consultant were created by the Consultant, rather than being information that is tracked and/or used by MH.

- In assessing any alleged deficiency, it is important to recognize that models are inherently imperfect. Models simplify reality in order to make problems manageable. They are a decision-making tool rather than a perfect representation of reality. Simplifications may also arise because of deficiencies in source data, limitations in the analytical approaches that are available, or limitations on the amount of resources that can be applied to an issue. A key issue in evaluating any model is thus whether the approximations that are inherent in them are appropriate in the circumstances.

- All forecasts are subject to error. Errors should be minimized but they cannot be eliminated.

Further specific factors that we have considered are described in the individual topic areas discussed later in this Chapter.

3.3.1 Approach in Review of HERMES

For the review of HERMES, our work included examination of the following three components: model concept and logic, model assumptions and data, and model operation and oversight.

3.3.1.1 Model Concept and Logic

In this component, the focus of our review is determining whether the model is a reasonable representation of the actual situation and can be used for the intended purpose. The specific questions that we have addressed in this component are:

- Does the model have a clear and logical structure?
- Does the model capture the variables and the relationships that are expected to affect the outcomes to be modeled?
- Are the concepts and relationships used in the model to link variables and outcomes easily understandable and theoretically sound?
- Did the model developers possess the training and experience needed to develop the model? This is a factor to be considered given that significant judgment is typically required in the development of complex models and that the ability to make appropriate trade-offs among modeling approaches depends on the training and experience of the model developer.
- Was the model reviewed by an independent expert?
- Was the model validated by testing against actual outcomes?

3.3.1.2 Model Assumptions and Data Used

This component of our review is focused on the data and assumptions used in the model. The data and assumptions used in the model have a direct impact on the results of the model, and hence it is important to assess their accuracy and reliability.

In the case of HERMES, there is an extensive array of data and assumptions that are used as model inputs. We have concentrated our efforts on those assumptions that were identified as deficiencies in the Consultant's report.

The specific issues addressed in our review are:

- model optimization method;
- antecedent forecasting of water flow;
- power price forecasting;
- market developments;
- potential errors in price inputs;

- data on historical flow record;
- lake level balances;
- lake level balances discrepancies;
- production coefficient data;
- storage option modeling techniques; and
- volume risk.

When identifying concerns with the data and assumptions in MH's models, the Consultant in many cases quoted financial values associated with "model risks" or "operational errors". It is not always clear what these values are intended to represent. Depending on the context, each value may represent one or more of the following:

- An estimate of the risk associated with forecast financial results or, in other words, the potential variability in results from the expected value.

- An estimate of the direct financial losses incurred by MH relative to the results that it would achieve if not for the operational errors.

- A measure of the capital that needs to be set aside as a result of a particular activity to cover the potential variability in financial results and to ensure MH's financial solvency.

- A measure of the variation in market value (e.g., for a contract) that may occur with changes in market conditions or prices. Such changes in market value may not represent an immediate financial loss, although they may represent an opportunity cost. For example, the decline in market value of a long-term contract may represent the change in the present value of future expected earnings from the contract, relative to spot market sales, but not an immediate cash loss.

The nature of the "model risk" will determine the implications of that risk for MH.

It should also be noted that model forecasting errors do not lead directly to "operational errors". The models that we reviewed are used for planning. They support management decision making but are not used for operational purposes. Operational factors that are ignored in the models may still be taken into account in day-to-day operations.

It is beyond the scope of our review to review all the values presented in the Consultant's report. We have, in selected instances, attempted to replicate the

Consultant's estimates in order to understand the nature of the Consultant's assertion regarding deficiencies in MH's models. Our focus is on understanding the substance of the Consultant's assertions and determining whether the assertions have merit.

3.3.1.3 Model Operation and Oversight

This component of our review focused on how the model is operated and used. The specific questions we seek to address are:

- Is there a process in place to guide the day-to-day operation and revision of the model?
- Are there quality assurance procedures in place to ensure that the model results are reliable (e.g., checking of data inputs, review of results, report signoff)?
- Do constant revisions in the forecasts as a result of weekly updates create additional risks for MH?
- Do model results take into account risks in forecasts and assumptions?
- Are model results and limitations appropriately communicated to management?
- Are there policies and guidelines for the use of models?
- Are the responsibilities for model development, operation, and validation clearly defined?
- Is the model properly documented to enable knowledge retention in the event of loss of key modeling staff and to facilitate independent review, training of new staff, and verification?
- Does management apply reasonable care and due diligence in the use of the model results in decision making? (This is also addressed in Chapter 6.)
- How are results interpreted and used in decision making? Do users understand the inherent uncertainty in the results of the model and not over rely on the model?. (This is also addressed in Chapter 6.)

3.3.2 Approach in our Review of SPLASH and PRISM

For SPLASH, we conducted a high-level review of the following:

- concept and logic used in the model;
- consistency of assumptions and modeling approach with those of HERMES;
- the issue of perfect foresight;
- conceptual issues in the modeling of drought risk
- observations on the limitations and use of the model; and

For PRISM, we conducted a high-level review consisting of the following:

- concept and logic used in the model;
- the use of current data inputs;
- similarity of assumptions and modeling approach with those of HERMES and SPLASH;
- observations on the limitations and the use of the model; and
- suggestions on improvements.

3.3.3 Other Approach Comments

Our review of the models consisted of examining the three components identified above, namely model concept and logic, model assumptions and data use, and model operations and oversight. We have not, however, attempted to comprehensively verify the data and assumptions used in the model.

Because MH operates in an uncertain environment and because models inevitably have limitations, it is expected that MH will make decisions that, in retrospect, are not optimal. As an example, the Consultant notes that the antecedent forecasting process, used to estimate near term water flows, has sometimes resulted in the release of water that would have better been kept in storage. It is beyond the scope of this review to determine, with the benefit of hindsight, whether individual decisions made by MH management were optimal. Rather, our focus has been on assessing whether the modeling approach is reasonable and appropriately takes into account information that is available at the time of a decision.

3.4 Overview of Models

In this section we provide a brief description of each of the three models and how they are used by MH. The descriptions are based on documentation provided by MH and the findings of our interview process.

3.4.1 Description of Models

3.4.1.1 HERMES

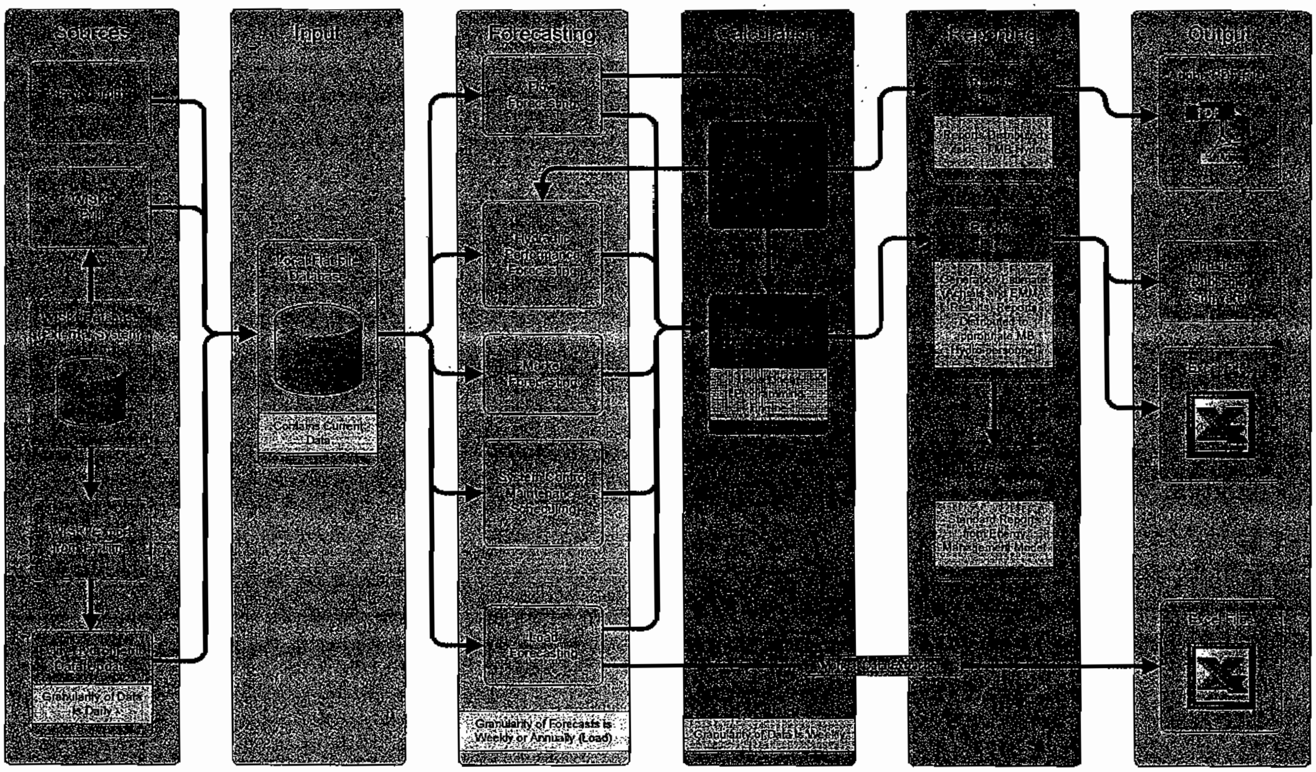
HERMES (Hydro Electric Resource Management Evaluation System) is a planning tool and decision support system used by the Power Sales and Operations group to support hydraulic operations planning. It provides a suggested water release schedule and associated production estimates over the planning horizon of 12 to 16 months. While management uses HERMES as a support tool in making water release decisions, these decisions incorporate broader considerations. HERMES can also be used to identify the probable cost of serving proposed sale transactions.

HERMES takes into consideration a broad set of data in order to model the state of the system. Input data to HERMES includes:

- hydrologic information;
- hydraulic system characteristics;
- generation maintenance schedule;
- load requirements;
- export/import contracts;
- export/import power prices; and
- internal and external transmission characteristics.

Exhibit 3-1 provides a graphic representation of HERMES.

Exhibit 3-1: HERMES Application Architecture



Source: Manitoba Hydro

There are two key calculation modules in HERMES that are used to produce the various reports to support operations, power contracts and trading decisions. They are:

- EMMA (Energy Management and Maintenance Analysis) is the key operations planning module used to derive the operating plan to manage the system of reservoirs, generation stations and transactions with neighbouring utilities over a time horizon of up to one year.

- QSIM (or the Flow Simulation Model) is the module for deriving daily flow and elevation values along the hydraulic network affecting the MH generating system. QSIM complements EMMA by providing daily flow estimates compared to weekly and monthly estimates.

EMMA is an optimization model using linear programming approximations to minimize net system costs while meeting firm load requirements. The model operates in one-week and one-month intervals and typically produces one-year runs. EMMA is deterministic (one outcome given one set of assumptions) as opposed to stochastic (a range of outcomes based on a set of inputs with probability distributions). EMMA is run weekly and thus provides a forecast of future production that is continually updated to reflect new information on water flows and market prices.

QSIM is used to provide daily flow forecasts at most hydro sites and along rivers affected by MH operations. Flow forecasts are converted to energy production. This information is used by Power Trading for managing short-term (within the next week) energy supply in the system. More specifically, the information is used by Power Trading in maintaining desirable levels on Stephens Lake, which is the reservoir immediately upstream of the bulk of MH's generation.

HERMES, and in particular the EMMA model, is the main tool for medium-term power resource management. EMMA outputs are discussed at weekly resource planning meetings at which weekly production scheduling and weekly operating plans are determined. EMMA is also used in the preparation of Generation Estimate reports, which are in turn used to support MH's annual Integrated Financial Forecasts ("IFFs"), that are submitted to the PUB. EMMA, in contrast to SPLASH, includes representation of demand requirements and capacity constraints in the MH system. This reflects the fact that it explicitly models peak demand periods.

For short-term and real-time operations, MH uses a commercial hourly operations model plus other internal planning tools to maximize available resource utilization and minimize cost of meeting assumed obligations. These other tools are beyond the scope our report because they were not the focus of the Consultant's assertions.

3.4.1.2 SPLASH

SPLASH (Simulation Program for Long Term Analysis of System Hydraulics) was developed by the Resource Planning and Market Analysis Department between 1990 and 1996. The purpose was to provide a computational tool that can be used to study the economics and adequacy of various expansion scenarios and to evaluate the options and opportunities available in the electric power market. More specifically, SPLASH is to be used in generation expansion studies.

The output from SPLASH provides information to evaluate the economics of power resource options such as power export marketing contracts, system enhancements, and integration of non-hydraulic resource options such as wind energy and gas-fired combustion turbines.

The output from the SPLASH model provides information used to evaluate the economics of power resource options such as power export marketing contracts, system enhancements and surplus energy rate programs, as well as the integration of non-hydraulic power sources such as thermal (gas-fired and coal-fired) generation and wind-based power. As well, the system is capable of analyzing and incorporating regulatory restrictions and license constraints for the operation of the reservoirs, producing outputs for use in analyzing environmental impacts on river systems and water regimes.

One of the uses of SPLASH is to model the firm, or dependable, energy supply that will be available to service the Manitoba domestic load and contractually committed power export agreements. Firm, or Dependable Energy supply, is dependent on the volume of water flow during periods of drought, and therefore the firmness of the hydraulic supply is the first priority of system operating decisions in SPLASH. Thereafter, the system's linear programming logic is designed to maximize net revenues. This optimization of net revenues considers the economic opportunities associated with surplus hydro energy that is available for flows greater than the drought flows.

SPLASH is used to support financial forecasting. Within the IFF, SPLASH is used to generate production cost estimates for years beyond the forecasting horizon of HERMES.

A typical SPLASH run generally requires several hours of computer time, and involves solving the linear programming system through a series of iterations, with each simulation involving monthly time steps over a 40 year period and utilizing the entire historical flow record of 94 years.

3.4.1.3 PRISM

The length of time for a SPLASH run, and the deterministic nature of SPLASH logic, led to the demand for PRISM (Power Risk System Model), which provides more flexibility for doing multivariate scenario analyses.

For screening and preliminary analysis purposes, PRISM is a simplified tool used by the Export Marketing Department to analyze the financial impact of variations in a number of factors that affect Manitoba Hydro's operations. These factors include: water conditions, expected load, gas and electricity prices, export sales, transmission access, and wind energy. PRISM was first employed as a tactical tool for evaluating short-term hedging options under drought conditions. As a screening model, PRISM is designed to provide an initial estimate rather than a precise analysis, and is used to identify possible outcomes associated with fixed, pre-defined scenarios. Since it is a screening tool, strategies selected for further analysis or implementation will typically be subject to more detailed analyses using SPLASH, HERMES or other tools.

PRISM was initially recommended and developed by an external consultant (RiskAdvisory). PRISM provides the Export Marketing Department with a forecast of net revenue over five years, given inputs of domestic load, hydro and wind generation, electricity export prices and natural gas prices.

Inputs into PRISM come from approved MH resources, including the outputs of both the HERMES and SPLASH computer models. It uses these inputs to run a Monte Carlo simulation analysis of 1000 iteration runs, and reports a probability distribution of net revenue. (Monte Carlo simulation software takes inputs as random or stochastic variables and calculates a distribution of outcomes based on multiple runs, where each run reflects an outcome based on one sample of inputs.) Scenarios that have been analyzed using PRISM include low water conditions, high gas and electricity prices, variations in forward contract commitments, addition of gas and wind generation capacity, and changes in the operating licenses of generating stations.

3.4.2 Operational Context for Models

In evaluating the use of models at MH, it is important to consider the context in which it operates and the types of decisions that the models are designed to support.

3.4.2.1 Reliance on Short-Term Sales

Water volumes at MH are subject to wide swings from year to year. The year-to-year variation in water availability is much larger for MH than for most other large hydroelectric utilities. The lowest flow year on record has less than 50% of the flow of the median year. The highest flow year is more than 50% greater than the median flow year. Hence the highest flow year is more than three times the level of the lowest flow year. The variability in water flows has important implications for the design of the system, MH's export sale strategy, and the focus of modeling work.

Further, even within a year, future water flows are highly uncertain. Flow volumes can change dramatically based on the volumes of spring rain and, to a lesser degree, the extent of snow melt. MH relies on its antecedent forecasting process in its production planning process, but the predictive power of this methodology is inherently limited. Antecedent forecasting uses regression analysis to predict future water flows based on current flows.

Uncertainty in water flows results in MH selling much of its export power on a short-term basis in order to be highly confident that the power can be supplied. The percentage of MH's export sales made on a short-term basis fluctuates year-to-year depending on water volumes, and is considerably higher in high flow years. For fiscal 2008/09, which had higher water flows than average, over one-half of sales were made in Real-Time or Day-Ahead markets as well as other short-term sales. For their spot market sales, MH commits to deliver power, at most, one day ahead of time. Other opportunity sales are short-term, but are made outside of the spot market. A sales breakdown is provided in Exhibit 3-2.

Exhibit 3-2: Breakdown of 2008/09 Export Sales

Sales Category	Volumes (MWh)	Percentage
Opportunity Spot (DA and RT)	5,131,178	51%
Opportunity Term	904,036	9%
Dependable	4,087,093	40%
Total	10,122,307	100%
Hydraulic Generation in 2008/09 as % of Hydraulic Generation in an Average Flow Year	114%	

Source: derived from Manitoba Hydro

MH also enters into long-term contracts which are serviced from "Dependable Energy". Dependable energy is the hydroelectric power available under the lowest river flow conditions in the historical record, and also includes energy sourced from wind and thermal as well as firm and contracted non-firm imports. (Although the definition of dependable energy contains a number of non-hydroelectric sources, these sources remain a very small share of Manitoba's total production.).

To account for uncertainty in its water supply, MH is conservative in its export sales strategy:

- Long-term sales are limited to those that can be supplied from dependable energy.

- Opportunity sales made beyond the day-ahead and real-time markets are limited to those that MH is highly confident can be supplied based on current water conditions.

As a consequence of the reliance on spot sales, changes in forecasts of future longer term production, because of changes in parameters in HERMES, do not lead to shortfalls in MH's market position. MH does not commit to opportunity sales that are based on uncertain water flows, and consequently does not incur contractual or market losses when medium and long-term forecast water flows do not materialize. This is an important factor to consider in evaluating the risks of financial loss.

3.4.2.2 Model Projections are Support Tools and Do Not Translate Directly Into Financial Results

Models and their outputs are used as tools to support decision-making processes at MH. The outputs from models do not directly lead to business or market actions and do not translate directly into financial profit or loss. For example, HERMES generates forecasts of available energy and suggested production schedules. These forecasts of available energy, however, are not translated directly by trading staff into forward market positions. Similarly, suggested production schedules produced by HERMES do not lead directly to control decisions at MH hydroelectric facilities. This is elaborated upon further below in the section outlining the HERMES model.

3.4.2.3 Mandate to Support Load

A key output of HERMES relevant to the scope of this review is a forecast of the amount of energy available for export within each segment of time modeled. This forecast is used as a reference point for assisting energy trading operations. Because of the priority of meeting domestic load before any energy export commitments, and due to the requirement to mitigate chances of there being insufficient resources to serve forecasted load, the MH system is operated conservatively. Sales decisions are supported by various modeling tools within HERMES, such as load forecasting, water supply forecasting, capacity and reserve management, and deal analyzer modules.

In general, forward opportunity sales are not made unless MH has sufficient firm capacity and energy resources to serve the load 95% of the time. This means there is only a 5% chance that such firm resources will be inadequate. For drought management planning, the required level of confidence in planning energy supply increases to 99%. This risk target reflects the combined probability of a severe winter (defined as a one in 10 event) and water supply at the 5^{th} percentile level.

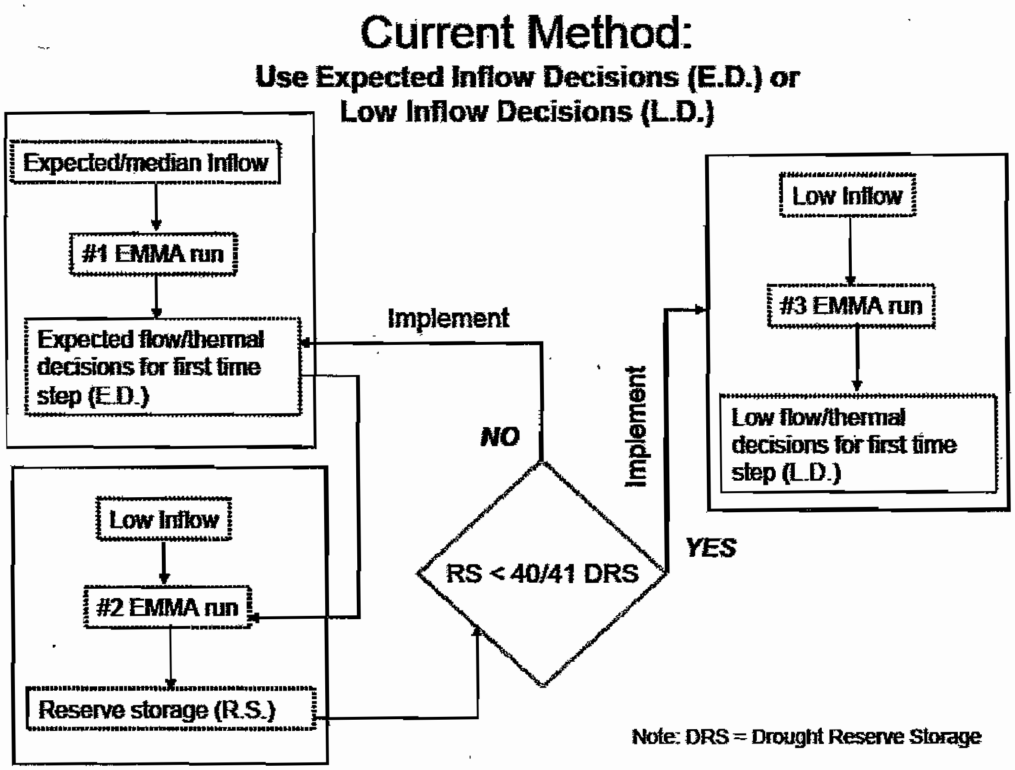
In the event that resources are projected to be inadequate to serve committed load, this will generally mean a draw-down in reserve storage levels, with a potential reduction in energy supply security in the second year of the projection horizon. In such event, water storage reserves will be replenished at the first opportunity, including from opportunity purchases and other non-firm sources.

MH management has adopted a conservative management approach in recognition of the following:

- the duration and extent of a drought is not known in advance;
- it is normal for it to be very cold in the winter in Manitoba, which can cause loads to increase dramatically; and
- the societal and financial consequences of running short of energy during an extended period of drought (especially in the winter) can be enormous relative to the potential income that might be achieved by being less conservative.

Reliability issues are also addressed in EMMA model runs within HERMES. As noted elsewhere, a standard EMMA run generates an economically optimal production schedule, based on its input assumptions. MH then tests this projected production schedule against a scenario in which low water flows occur. MH checks whether, under this low flow scenario, lake levels fall below Drought Reserve Storage ("D.R.S.") levels, which are the levels required to cover a repeat of 1940/41 drought flows. If not, then the optimal production schedule is implemented. If levels fall below D.R.S. levels, then the schedule is readjusted (see EMMA run #3 in Exhibit below) to ensure that the D.R.S. level constraint is not violated. Reserve Storage levels are those that ensure all firm commitments will be met even under historically observed low-flow conditions. This process is outlined in Exhibit 3-3 provided below.

Exhibit 3-3: EMMA Model Runs Related to Inflows



Source: Manitoba Hydro

It should be further noted that the implementation of a production schedule, in practice, involves a commitment for only the next week planning horizon. The EMMA model is run weekly, so updated forecasts are available with new information in the following week.

Production decisions taken for the current week will influence future production schedules because of the impact of these decisions on water levels at the beginning of the next week. (Greater production this week will mean less water in "inventory" next week.) Hence, decisions are linked in time. For any period, shortfalls in water inflows relative to forecast will inevitably lead to variances in financial results relative to forecast. Absent changes in the "spilling" of water, production scheduling decisions influence only the timing of the production shortfall and, hence, the timing of the revenue shortfall. (The magnitude of revenue shortfalls will be influenced, in addition, by differences in prices across periods.)

3.5 Review of HERMES - Model Validity

In this section, we present our analysis and conclusions to the component of our review addressing model concept and logic, as identified in Section 3.2.1.

Does the model capture the variables and the relationships that are expected to affect the outcomes to be modeled?

HERMES' primary use is to generate a suggested production schedule that will meet load requirements while maximizing net export revenues and minimizing production costs, given various input assumptions.

At a conceptual level, we would expect the model to incorporate data and assumptions from the following categories of inputs: power demand, lake levels, water flow, production capacity, import/export of power, product costs, and import/export prices.

In practice, there are significant challenges in modeling an interconnected hydroelectric system, particularly in the case of the MH system. These challenges include:

- The production characteristics of the system are complex and change continuously. First, the capacity of individual hydroelectric plants varies with current water levels (which affect both achievable flow rates and water head) and ice conditions. Further, for given input water level conditions, both turbine efficiencies and effective water head vary with the volume of water flows. These changes in system parameters are much more difficult to model than those associated with a thermal-based system.

- Many hydroelectric stations are interconnected – the water leaving one plant flows into other plants downstream.

- Models need to account for the travel time of water between plants and for the attenuation of water flows, or the smoothing of water flows from unit release patterns.

- The value of retaining water in storage depends on future water flows, demand and electricity prices, which are difficult to predict in advance. There are techniques available to consider uncertainties in these future conditions in identifying optimal generation decisions, but these entail additional computational complexity.

- While the ability of computer models to incorporate various factors has grown with technology advancement, even very complex models must introduce simplifications to keep the problem manageable. It is not practical for a model to capture all possible variables and relationships. It is important to consider the overall reasonableness of the modeling approach taken, i.e. the simplifications employed.

HERMES was developed internally to capture the unique characteristics of the MH system. A large number of variables have been captured, including: power price, flow, load growth, temperature, generation capacity (representation, outage), market access (transmission, market limit), and regulatory (licenses, reliability). The "bespoke" nature of HERMES is consistent with practices in the sector. One industry consultant notes: "Decision support systems are usually site specific and not readily transferable from one hydroelectric system to another." *(Source: C.D.D. Howard, Hydroelectric System Operations Optimization, Great Wall World Renewable Energy Forum and Exhibition, October, 2006.)*

Based on our review, the variables and relationships captured by HERMES appear to be consistent with the variables that one would expect to affect net export revenues and production costs.

Was the model reviewed by an independent expert?

An independent review is a review conducted by a party who was not involved in the development of the model. An independent review can be performed by in-house staff (e.g., Internal Audit) or by external reviewers. An independent review can help identify potential model deficiencies and enhance the credibility of the model.

Based on our discussions with MH staff, it appears that no structured independent review has been performed on HERMES. However, Operations Planning staff believes that HERMES is a reasonable representation of the MH system based on the long history of use.

On a periodic basis, Operations Planning staff presents the concepts and methodologies used in HERMES at industry forums for general comments. Examples of participation in these forums include a Hydro Workshop in Oslo in 2001 and the CEATI Hydro System Workshop in Vancouver in 2001. However, while participation in industry forums may enhance the knowledge of MH staff, it does not address the need for independent review.

Was the model validated by testing against actual outcomes?

Model validation is the process of comparing the outputs of a model with actual outcomes. Such a process is used to establish the reliability of a model. In general, if the forecasts produced by a model are reasonably close to the actual values, this increases confidence in the reliability of the model.

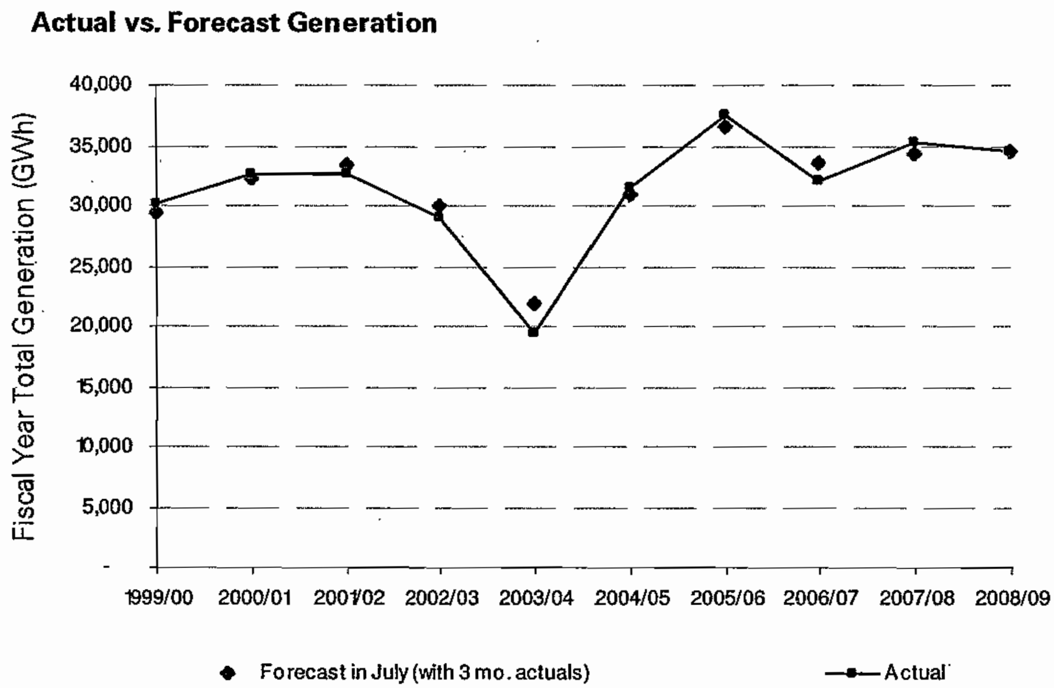
Fundamentally, HERMES consists of a number of forecasting modules (e.g., flow forecasting and load forecasting) and an optimization module to find the production schedule that minimizes production costs and maximizes net export revenues.

Based on our discussion with MH staff, it appears that no systematic validation has been performed on the forecasting modules.

While validation of individual forecasting modules has not been performed on a systematic basis, MH has compared key outputs of HERMES with actual data. Exhibit 3-4 below presents a comparison prepared by MH of forecast and actual generation for a fiscal year. The forecasts for each year are prepared in July of that year, and thus include actual data for 3 months. MH uses forecasts as at July for the comparison because these forecasts are generally the basis of the IFF for each year. IFF's are prepared in late summer. July is also a good point at which to forecast future production. It comes after the spring season, which is marked by rain and spring run-off and, hence, marks the point at which MH has a good view of its water inventory for the balance of the year.

As shown in Exhibit 3-4 the actual generation values are reasonably close to the forecasted generation values. Since actual generation is largely dependent on actual water flows and lake levels, Exhibit 3-4 indicates that the forecasting modules used in HERMES can take the data set available in July and produce realistic production plans for the remainder of the fiscal year.

Exhibit 3-4: Actual versus Forecast Generation



Source: Manitoba Hydro

The accuracy of financial forecasts is likely to be less than the accuracy of power production forecasts. The accuracy of financial forecasts depends on a variety of other factors in addition to water flow and power production. These other factors include import/export power prices, load, transmission constraints, and natural gas prices.

While it appears that the information available in July can be used to produce realistic production plans for the remainder of the fiscal year, MH staff has indicated that the situation is less predictable earlier in the year. This is because in February and March, the amount of spring rainfall is not yet known and the predictability of rainfall beyond the very short term is low.

Based on the above, the reliability of the forecasts produced by HERMES varies significantly depending on when in the hydrological year the forecasts are prepared. While MH management already takes this variability into consideration in making operation and business decisions, it would be beneficial to clearly communicate the amount of uncertainty to all recipients of HERMES outputs.

3.6 Review of HERMES - Model Operations

In this Section, we discuss the following related to the operations of the model:

- model operation;
- model revision process;
- model accountability and model use;
- proposed model enhancements, and
- model documentation.

3.6.1 Model Operation

HERMES is a "live" modeling system and is being run on a regular (at least weekly) basis. Up-to-date input data (on parameters such as water flows) are continuously entered into the system. Certain inputs are calibrated to ensure that actual observed measurements are incorporated into the model. Examples of inputs requiring calibration include powerhouse efficiency relationships and tailwater and lake outlet rating curves. Power efficiency relationships are updated following a physical change to the facility, such as a turbine replacement. Rating curves are generally reviewed weekly during the winter to ensure that they reflect changing ice conditions, which can impact water flows. Calibration requires continuous cross-checking by knowledgeable staff of data from various points in the system.

As indicated previously, the model is not operated in a purely mechanical manner. Operations Planning engineers apply professional judgment in the process to help ensure that the inputs and results are reasonable. For example:

- Operators select among a number of functional forms in selecting equations for the forecasting of water flows. Selection is based on an evaluation of "best fit". The review of the functional form may be done more or less frequently depending on the season, the stability of forecast relationships, and changes in inflow data.

- In developing forecasts of water flows, management may take into account information that is external to the modeling tools. Thus, while water flow forecasts are generally based on the forecasting equations, management may use data on snow accumulation to adjust the forecast above or below the median expected value generated by a forecasting equation.

- The EMMA model within HERMES requires projections of future market prices. While data on future market prices are purchased from an external consultant, management on at least one occasion adjusted those forecasts downward when it believed that the price forecasts were overly optimistic.

- Model reviews are conducted internally in Hydraulic Operations, frequently involving PS&O management. Depending on the topic, staff from other areas of MH may be involved in concept reviews (e.g., Hydraulic Operations and Resource Planning and Market Analysis of the Power Planning Division).

The logic of the models does not generally capture management judgment. Management judgment is applied either in the use of the model outputs or in the development of input assumptions. This is appropriate given that the models are a decision-support tool rather than a direct means of operating the business.

3.6.2 Model Revision Process

The core framework of HERMES has not changed since its original development. Incremental changes have been made to ensure the model continues to represent current operations.

According to MH staff, adjustments to the model generally involve the following steps:

- identification of a driver for change (e.g., change from bilateral market to open MISO market);

- Operations Planning team conceptualizes and develops solution;

- coding changes made in "Development" and "Test" environment to test for robustness and reasonableness;

- new executable program is deployed during a low use period;

- Operations Planning staff evaluates incremental changes through review of relevant reports;

- affected groups are notified of the change;

- details of code changes are documented; and

- previous versions of code and database are backed up daily.

We consider the process as outlined by MH to be reasonable. The model revision process is managed by the Operations Planning section within Hydraulic Operations, the primary group responsible for HERMES. There is, however, no formal requirement for an independent or internal review of how the model revision process was followed. While we understand that HERMES is a "live" model and is being run and calibrated weekly, and hence problems are likely to be identified quickly, a structured review of the model and related processes on a periodic basis (e.g., once a year) would improve stakeholders' confidence in the credibility of the model and help to manage modeling error risks.

3.6.3 Model Accountability and Model Use

MH does not have a specific policy statement on the development and use of modeling tools. Modeling tools are managed through the application of existing approval and risk management policies and procedures. Modeling tools are developed within business units to meet specific needs.

For HERMES, the Operations Planning section within Hydraulic Operations is the primary group responsible for database updates, calibration, maintenance and use of the HERMES model. This group also leads model changes.

Other business units provide inputs and data updates. Model maintenance and code changes are implemented with the support of a dedicated Senior Applications Support staff member in the Market Process & Technology department. The Power Trading Supervisor in the Power Trading department is responsible for updating and ensuring that the export contract commitments are updated in the HERMES system.

Engineering staff in Operations Planning is responsible for model maintenance and calibration. Through regular weekly updates, senior engineering staff reviews HERMES outputs, typically in an integrated manner by reviewing results of the EMMA model, which is driven by the other modules in HERMES.

On a weekly basis, inputs and results of HERMES are reviewed at Production Scheduling Meetings participated in by Hydraulic Operations staff, Power Trading staff, Senior Risk Management Officer, Short Term Generation Scheduling, and Mitigation Department staff. This ensures that results are discussed with key operational personnel.

An important factor to note is the "live" nature of the HERMES model. As indicated previously, the model is continuously updated with new data and recalibrated. This process can be expected to improve the accuracy of the forecasts. However, this also means that the forecasts will be changing continually. We do not consider that this continuous update process presents an additional modeling risk in itself. However, it is important for users of forecasts from HERMES to recognize the fact that forecasts continually evolve, especially for staff outside of Operations Planning who use the information.

Projects for model development require line management approval and, depending upon size, may require Executive Committee approval. Requests in Power Supply for models that require major commitments of resources are prioritized through the Power Supply IT Coordinating Committee before being forwarded to Corporate IT for inclusion in the Corporate priority setting and approval process. At the point in time when models are recognized and incorporated into major business processes, a capital budget item is raised and, if greater than $2 million in projected cost, is approved by the Executive Committee. Corporate IT and PS&O utilize a project development and management process called Macroscope which follows the project through its life cycle.

The staff members responsible for maintenance and operation of the HERMES modules typically have graduate-level degrees in engineering. Staff appears highly motivated and interested in improving the performance of the system on an ongoing basis. The complexity of the MH system and of the optimization issues offer significant scope for ongoing analysis and improvement.

Our understanding from discussions with management is that it takes a long time for new recruits to fully understand and appreciate the characteristics of the Manitoba hydroelectric system and its representation in HERMES. Accordingly, management puts significant effort into on-the-job training and coaching of new hires by more senior personnel. Management typically also hires additional staff at the junior level to account for the fact that some may leave the organization or fail to develop the required competencies. Succession planning is thus implicitly an important element of MH's process for model management and upkeep.

The movement of staff within the organization provides some benefits in terms of knowledge transfer and sharing. Staff members have moved from the SPLASH team to the HERMES team or vice versa or have rotated into or out of positions in the MH control center. This helps to ensure that the various models are consistent and capture relevant aspects of company operations.

As noted elsewhere, MH has developed its main modeling tools in-house and has thus relied heavily on internal expertise. One potential weakness of this approach is that staff members may have had limited direct exposure to modeling practices at other agencies or utilities. Formal peer review or benchmarking exercises would help ensure that MH benefits from experience elsewhere. It would also ensure that potential alternative modeling approaches are fully considered.

3.6.4 Proposed Model Enhancements

MH has a number of active or planned initiatives to enhance the HERMES system.

3.6.4.1 System Representation

MH is planning changes to the representation of certain system characteristics within the model. It proposes to change the approach to representing the power curve (i.e. the power versus flow relationship) within the Linear Programming formulation. The change will be from an iterative approach to one in which the relationship is found directly within the LP formulation. This model change is expected to yield improved solution stability and increased accuracy of absolute results. MH is also modifying the approach to modeling rating curves, which capture non-linear reservoir storage versus outflow relationships. This enhancement is expected to decrease the size of the LP formulation.

3.6.4.2 Stochastic "Tree" Model

As a longer-term project, MH is planning the implementation of a stochastic decision support model that incorporates water supply, energy market, and Manitoba load uncertainty within the optimization. The EMMA model will be configured to step through time and recommend release decisions for key reservoirs at that point in time, given a multitude of possible future input conditions. This model will allow consideration of uncertainty within a linear planning framework.

3.6.2.3 Model Renewal

In the coming year, Power Sales & Operations will be developing a plan to renew the HERMES system. Potential changes include: a new LP solution engine; change from a flat file to a relational database; improved interface capability with supporting systems; enhanced GUI; and assessment of human resource requirements for model maintenance and development from an engineering aspect and also from information technology point of view.

3.6.5 Model Documentation

The operation of the HERMES system requires highly specialized skills and knowledge in the operations of the MH system. Training is based on the transfer of expertise by senior engineers on the proper use of the models and interpretation of the results to trainees on a one-on-one basis.

Documentation on specific modules or aspects of the model is prepared to assist in knowledge transfer on an ad hoc basis. No detailed user's manual or comprehensive model documentation has been developed. MH considers that there is only a very limited number of staff with responsibility to operate the model who would need that documentation.

KPMG recommends that MH develop more formal model documentation. Such documentation will reduce risks associated with the departure of key modeling personnel and it will help internal and external stakeholders better understand model structure and logic. The development of documentation will require additional resources.

3.7 Review of HERMES – Model Assumptions and Data

HERMES requires a large array of data and assumptions in order to carry out the calculations and produce the required outputs. In this section, we provide our analysis on the topics identified previously in Section 3.3. These topics are:

- model optimization method;
- antecedent forecasting;
- pricing data inputs;
- market developments;
- potential errors in price inputs;
- data on historical flow record;
- lake level balances;
- lake level balances discrepancies;
- production coefficient data;
- storage option modeling techniques; and
- volume risk.

3.7.1 Model Optimization Method

3.7.1.1 Linear Programming Approach

One of the key assumptions in the HERMES system is that the operations problem can be represented with a linear programming formulation. Linear programming methods have been accepted in the electricity industry as a useful means of solving large hydro-scheduling problems. *(Source: A.J. Wood and B.F. Wollenberg, Power Generation, Operation, and Control, John Wiley & Sons, 1996, p. 250.)* Advantages to linear programming include its ability to efficiently solve large-scale problems, its ability to converge to global optimal solutions, and the ease of problem setup and solution. *(Source: J. Labadie, "Optimal Operation of Multireservoir Systems: State-of-the-Art Review", Journal of Water Resources Planning and Management, March/April 2004, p.97.)*

At their core, both the HERMES and SPLASH models have a linear programming routine to optimize production schedules, taking into account system constraints and the need to serve customer loads. The linear programming logic identifies the production schedule that results in the lowest net system costs, or, in other words, the lowest value for production costs less net export revenues. The optimization approach is deterministic. This means that at the starting date, all of the various parameters (e.g., prices, flows, load) are assumed to be known and are taken into account to optimize the production schedules during the optimization period. (It should be noted that SPLASH performs this optimization process for each of the 94 flow cases that are available as inputs. This allows consideration of flow uncertainty in the computation of expected results. For each iteration, however, flows are assumed to be known.)

To illustrate this point, for example, a suggested water release schedule for January will be included in a solution provided by a model run in December. This solution will be established using forecast information for water inflows in the following months. However, in real life there is uncertainty around these forecasts. In light of this uncertainty, it is not possible to make "perfect" or optimal decisions, even though it may be possible to make decisions that have a higher *expected* value than other decisions. This is what is referred to as the perfect foresight issue by the Consultant.

Issues arising from perfect foresight are likely to be more significant in extreme flow scenarios (drought or flood years). Under these conditions, the optimization model may recommend extreme decisions "knowing in advance" that a drought or flood will materialize. The model also "knows in advance" when the flood or drought will end. In real life, it would be impossible to know in advance the timing of those events and management will not, in practice, make these extreme decisions. Overall, it is likely that the HERMES and SPLASH models may then give more optimistic results than what would actually happen in real life under a flood or a drought scenario. By optimistic, we mean that it will tend to understate the actual costs incurred.

In HERMES, risks associated with the perfect foresight assumption are mitigated by testing any given production schedule against a low flow scenario. In other words, when a solution (e.g., a water release schedule for each period) is found through the HERMES model, the release schedule found is then run through the worst flow year on record. If the ending reservoir levels, using the optimal release schedule and the low flow year inputs, are below the minimum level required at the end of the planning horizon for reliability purposes, the release schedule is not implemented and another optimization is performed. This test was discussed in more detail in Section 3.4.2. This process counters the fact that the deterministic solution approach could lead to insufficient water levels in low flow years in the event that such low flows were not forecast in advance.

3.7.1.2 Alternative Optimization Approaches

MH staff are aware that algorithms in the scheduling models take inputs as known events and therefore do not account for forecast uncertainty. MH is also aware that there are other ways to deal with the optimization problem that do not assume perfect foresight. For example, there is an optimization approach called dynamic stochastic programming that can deal with optimization under uncertainty.

The basic working of dynamic stochastic programming is to perform a step-by-step optimization (for example, using a monthly time step) while taking into account the variability of all the parameters at the next step. Therefore the information about the state of the system is revealed step-by-step. The inputs entered into the model would no longer be a single forecast but could be a range of forecasts designed to represent the distributions of the outcomes possible for variables such as electricity prices, natural gas prices and water inflows.

The optimization criteria could also be modified. For example, it could be to maximize the expected value of the revenues, or to maximize the minimum revenue obtained in the worst case scenario (min-max optimization).

There are several examples in the utility sector where optimization under uncertainty has been applied to mid-term forecasting problems. FPL Energy Main (FPL) has reportedly developed a decision support system that includes, among other things, a stochastic mid-term inflow forecast module and a module for stochastic storage optimization including energy price forecasts. Bonneville Power Administration (BPA) is developing a mid-term (52-weeks) stochastic optimization model. For both FPL and BPA, short-term models remain "deterministic". *(Source: C.D.D. Howard, Hydroelectric System Operations Optimization, Great Wall World Renewable Energy Forum and Exhibition, October, 2006.)*

However, the dynamic stochastic programming approach, while addressing issues of uncertainty, also has its own limitations. The most important limitation is called the "curse of dimensionality". Given its step-by-step nature and the fact that it explores alternative states of one or more of the variables, the number of calculations required can multiply rapidly as the number of variables and states grows. This is a particular issue in the case of MH because MH has an extensive hydroelectric system with significant interaction among its components. For the kind of problem that MH needs to solve, the number of variables, states and constraints could be large. As a result implementing dynamic stochastic programming could be a very challenging undertaking for MH and, hence, a major investment.

3.7.1.3 Modeling Improvements

Based on our review and on discussions with Operations Planning staff, the optimization approach used by MH appears reasonable and logical. There are other optimization approaches that could be used, but it is beyond the scope of our work to assess whether these would yield materially better results.

Our discussions with MH staff show that they are aware of the limitations of the current approaches, of possible alternative approaches, and of the limitations or difficulties in implementing these alternatives.

Given ongoing evolution in optimization approaches, however, MH should continue to examine potential alternative approaches to production and system planning. Plans for model development, noted earlier in this Chapter, indicate that MH is continuing to enhance the system over time.

MH currently has no plans to change to a different solution algorithm, such as the use of dynamic stochastic programming. However, MH is consistently improving its current approach to deal with known issues. To explicitly address forecast uncertainty, MH is exploring some new methods, such as the development of a stochastic "tree" model. (This model was discussed earlier in 3.6.4) This model may be used to test alternative decision rules under multiple flow scenarios. In this way, optimal decision-making approaches under uncertainty can be found.

Within the last three years, HERMES has been upgraded to facilitate the analysis of multiple water flow scenarios. Thus, the storage value function for lake water levels is developed by testing the impact of different lake levels on net export revenues and costs over the following two year period. This allows storage values to be calculated within HERMES. Formerly, these values were calculated in SPLASH and transferred to HERMES.

MH can also now set its models to use particular scenarios for water flows, such as the lowest flows on record, in generating forecasts of financial and operating results. This allows MH to identify the impact of these scenarios, and therefore get an understanding of the potential variance in outcomes relative to expected values. This helps to address the fact that HERMES and SPLASH do not allow full "Monte Carlo" or multivariate stochastic analysis.

3.7.2 Antecedent Forecasting of Water Flow

3.7.2.1 Concept of Antecedent Forecasting

MH uses a methodology called "antecedent forecasting" in the projection of water flows. The antecedent forecasting methodology is a statistical approach that assumes that current water flows have predictive value in forecasting future water flows. MH applies this methodology primarily in forecasting water flows in the remaining months of the current hydrological year (April 1 to March 31). Around December of each year, the forecast is extended to cover both the remaining months of the current hydrological year and the next hydrological year. In general, if current water flows are higher than historical average, the methodology predicts that future flows in the remaining hydrological year will also be higher than average. The antecedent methodology is applied using regression analyses. Relationships between water flows in future periods of a hydrological year and the current flows are developed using historical flow data.

The concept behind the relationship between future water flows and current water flows is based on the dynamics of water flow in the hydrological system. For systems that are relatively shallow and have features such as marshes and swamps, which is the case for MH's system, water flows following precipitation events tend to be delayed and attenuated. In these systems, a sudden inflow of water into a water basin, such as from a large rainstorm, will not immediately result in a corresponding flow increase in the associated river. Some of the water inflow will be stored in the ground or in intervening tributaries and will take some time to flow out into downstream rivers and streams. As a result, the water flows are "smoothed" over a long period. Because of this smoothing effect, water flows measured in a given week or month are expected to be correlated to future weeks and months.

Based on our review of MH data and conversations with MH personnel, it is clear that the predictive value of antecedent forecasting varies over the course of the hydrological year. By its nature, the predictive power of antecedent forecasting declines for time periods further in the future. In addition, among the months, March has the lowest predictive value. Our understanding is the major influence on water flows later in the year is the amount of rain in late spring. In March water flows do not yet reflect the impact of the spring rain. As a result of this factor, the hydrological year is set by MH to begin in April 1 of each year.

In the course of our benchmarking process, we found that New York Power Authority also uses an antecedent, or regression-based, forecasting approach. A document from the New York Power Authority (NYPA) notes: "The St. Lawrence River flows are forecasted using seasonal regression models. Variables used for prediction are the Niagara River flow the current month, the St. Lawrence River flow last month and the time of year." *(NYPA's Hydro Generation Forecast, Rich Mueller, January 2006, as quoted in letter addressed to Mr. Arnold Bellis, from PACE Global Energy Services, April 21, 2006, p. 11 of 12.)* The same document also indicates, however, that NYPA uses meteorological data, and modeling of physical parameters such as lake evaporation, in its forecasting of Niagara River flows.

MH management indicates that antecedent forecasting is an appropriate approach for MH for the following reasons:

- The water basin for MH's system is large and shallow. Much of the water that will flow into MH's generation stations in the near future is already in the ground or in rivers and streams upstream of its system. This water will arrive over time and the current measured flows represent part of that water.

- Forecasting future water flows based on weather forecasts may not be appropriate for MH because MH requires forecasts for months ahead and weather forecasts that far ahead are not be very reliable. Also, collecting weather data for a large system such as MH's would require significant resources. The large size of MH's catchment area means that input from a very large number of precipitation gauges would be required to accurately monitor precipitation in the catchment area. In many areas, particularly in the north, there may be relatively limited number of stations for monitoring such precipitation.

- Further, even if good data were collected, it is not a straightforward exercise to model how such precipitation will be translated into future water flows. For example, significant amounts of snowfall may sublimate (transform back into water vapour) without resulting in additional water flows in downstream rivers and lakes. For snow that does result in run-off, the timing of this run-off is highly uncertain. Modeling difficulties are increased by the large watershed area.

KPMG recognizes that the forecasting methodology should fit the uniqueness of the system. These arguments provided by MH management are reasonable. We have not investigated whether another forecasting approach, such as using weather and detailed hydrologic forecasting would provide more reliable or accurate forecasts. Based on our research, however, there is a considerable body of knowledge around weather and hydrological forecasting for hydro utilities. This body of knowledge will continue to evolve and MH will need to actively monitor developments to assess when implementation of new approaches becomes appropriate.

3.7.2.2 Issues with Antecedent Forecasting

In its reports, the Consultant raises issues regarding the antecedent forecasting process and the use of the antecedent forecasts (*Consultant's Report, December 2006*). Specific points raised were:

1. "The antecedent forecasting method adds a layer of modeling assumptions and operational errors to forecasting."

2. "…the antecedent forecasting can lead to a mistimed anticipatory release of water, or reduction and lowering of lake levels which is an operational mismanagement decision as opposed to a true volumetric risk."

With respect to the first point on an additional "layer" of modeling assumptions, we are unclear as to Consultant's preferred alternative. However, based on nearby references in the document to "baseline volume risk" and "deviations from median or average expected flows", one interpretation is that the Consultant believes that the historical median or average flows should be used as the baseline forecast instead of the results of the antecedent process. Alternatively, the Consultant may simply believe that, in the event that antecedent forecasts continue to be used, risks associated with this methodology should be separately quantified. This reflects the fact that, because MH uses a different forecast from the historical median or average, there is conceivably an additional layer of risk that has been introduced. With respect to these interpretations, we note:

- From a risk quantification perspective, it may make sense to measure pure water flow variability around historical median or average values. However, the main purpose of the HERMES system, and hence the need for flow forecast, is as a tool to assist in operational planning. For this purpose, MH requires forecasts that can best predict the future. In this context, one would use all available information to improve the accuracy of the forecast, including current flows if appropriate.

- From an operations perspective, it is not clear what practical benefit would be obtained from precisely measuring the quantum of risk associated with antecedent forecasting. To the extent that such forecasting improves results on average, it should result in a reduction in risk overall, even though it may have led, in certain instances, to incorrect decisions (which can only be determined with the benefit of hindsight). Based on our analysis below, there is good reason to believe antecedent forecasts do improve decisions and therefore reduce risks overall.

We have conducted a limited review of the regression data that underlie the antecedent forecasting used by MH. The following table presents the R-square, t-statistics and p-values of the regression between the energy-equivalent of flows in a month and the energy-equivalent of flows in the remaining hydrological year. T-statistics and P-values are presented for the coefficient that relates flows in the remainder of the year to the current month. Flow data from all inflows are converted to energy using production coefficients and added up to yield the total available energy in the system.

Exhibit 3-5: Regression Analysis of Water Inflows

Current month	Remaining period in hydrological year	R-sq	*t Stat* *(Slope Coefficient)*	*p-value* *(Slope Coefficient*
March	April to March	0.25	5.40	5.7E-07
April	May to March	0.35	6.84	1.1E-09
May	June to March	0.37	7.12	2.9E-10
June	July to March	0.44	8.27	1.4E-12
July	August to March	0.53	9.92	5.9E-16
August	September to March	0.36	7.04	4.2E-10
September	October to March	0.52	9.71	1.5E-15
October	November to March	0.50	9.37	7.8E-15
November	December to March	0.65	12.74	1.4E-21
December	January to March	0.81	19.42	2.2E-33
January	February to March	0.71	14.42	8.6E-25
February	March	0.53	9.91	6.2E-16

Source: derived from Manitoba Hydro data

As shown in Exhibit 3-5, the relationship between inflows in a month and inflows in the remaining months of the hydrological year appears to be meaningful at a reasonable level of confidence, with p-values below 0.001. (In statistical hypothesis testing, a p-value is the probability of obtaining a test statistic as least as extreme as the one that is actually observed assuming that the null hypothesis of no regression relationship is true.)

It is beyond the scope of this review to determine whether the antecedent forecasting used by MH is the best methodology. We do, however, observe that there is statistical basis for the use of antecedent forecasting. Given this statistical significant relationship, it can be expected that antecedent forecasting would provide a better prediction of future flows than simply using long-term historical median flows as the predicted flows. Linear regression has been a standard approach to seasonal streamflow forecasting for almost a century. *(Andrew Wood and John Schaake, "Correcting Errors in Streamflow Forecast Ensemble Mean and Spread", Journal of Hydrometeorology, 2008, Volume 9, p. 132.)*

With respect to the second point on "leading to operational mismanagement", it is certainly true that antecedent forecasting can lead to operational decisions that will prove to be incorrect. However, this is true for all forecasting methodologies, antecedent or otherwise. Compared to using simple historical averages as forecasts, antecedent forecasting is expected to be more accurate on average and hence lead to better operating decisions over time.

3.7.2.3 Potential Alternative Methodologies

An alternative approach to forecasting water flows based on current observed flows is to develop a model that takes actual precipitation data, and potentially also forecasts of future precipitation, and projects future water flows based on full modeling of the flow of water through the environment. Our understanding, based on discussions with an expert in the field, is that this is becoming more practical with the increasing use of satellites to assist in the collection of rainfall data. *(Conversation with C.D.D Howard, February, 2010.)* Satellites can receive data from remote monitoring stations and, ultimately, may be able to measure rainfall directly.

It should be noted that development of such an approach would be a major undertaking and would take a major investment in system development. There are grounds to believe that this approach will be more challenging for MH than for other hydroelectric utilities. This reflects the following:

- The watershed of MH covers a particularly large area, meaning that a very large number of monitoring stations is required.
- The nature of the terrain (flat and relatively porous) means that there may be significantly lags in the flow of water through the environment, which increases the challenges of correctly modeling the translation of precipitation into stream flows.
- Our understanding is that models used in this approach need to be continually calibrated and this will require resources for ongoing model update. In addition, the skills and expertise may not be currently available within MH.

Below we summarize our observations on the use of antecedent forecasting by MH:

- There is statistical validity in the use of antecedent forecasting.
- Antecedent forecasting is used by other hydro utilities including New York Power Authority (NYPA).
- There are other ways to forecast flows such as the use of precipitation and topographic data.
- It is beyond our scope to determine whether the use of antecedent method by MH is the best approach among the available alternatives.

3.7.3 Power Pricing Data Inputs

In this Section, we discuss the issues related to the pricing data inputs to HERMES.

We have a number of general observations with respect to this issue:

- Since the Consultant's initial report, MH has updated its process for incorporating market price outlooks into the production planning process. MH purchases price forecasts for the next 12 months on a monthly basis and uses these forecasts to update hourly pricing assumptions within HERMES. At the time of the Consultant's initial report, the link between model price assumptions and purchased forecasts was less clear.
- MH is involved in an ongoing effort to evaluate market price patterns and, in the period since the Consultant's initial report was written, has taken significant care to analyze and account for the factors that influence the prices associated with export and import transactions. As discussed more fully below, it is not sufficient for MH to have up-to-date data on expected spot market prices in MISO. MH needs to account for the various factors that will influence the prices that MH will actually receive. We have found that MH puts significant analytical effort into assessing these factors and accounting for them in its modeling approach. Furthermore, the analysis of market pricing is updated as new market data is accumulated over time.
- This ongoing effort enables MH to monitor and respond to changes in market price patterns as a result of market shifts. Significant changes in market price patterns have occurred recently, for example, in response to the increase in wind generation in MISO and as a result of the economic downturn.

- Changes in market price patterns are only part of the uncertainty that MH must address. MH maintains that, in practice, uncertainty related to water flows and domestic load have a greater impact on optimal operation of its hydroelectric system than changes in market prices.

- In certain instances, the Consultant's assertions of price discrepancies appear to result from its mis-interpretation of model outputs. This issue is discussed in 3.7.5 on differences in prices in fiscal 2006/07.

3.7.3.1 Future Prices

While MH staff put significant effort into modeling future prices and price relationships (e.g., peak/off-peak differentials and nodal price differences), MH management maintain that market price changes have only a limited impact on optimal production schedules. This reflects the following:

- There are a number of system constraints that limit MH's ability to change production patterns. One constraint is the need to maximize outflows from Lake Winnipeg during winter months to meet temperature-related demand and to offset the impact that winter ice cover has on hydroelectric production capacity. Lake levels must also be maintained within limits set by licensing requirements. Another constraint is the limits on transmission capacity to the US, which restricts MH's ability to reschedule electricity transactions in the MISO market.

- Variability in water inflows and temperature related-load have much more significant impact on optimal production schedules than market price variation.

In allocating its modeling and analytical resources across various issues, MH management believes that it has put an appropriate emphasis on price issues relative to other factors. Based on our review of the models, their outputs, and the context in which they are used, MH's assertion that price has a limited impact on optimal production schedules generated by the model appears reasonable.

While these factors support the idea that price is not the most important factor in making operating decisions, it would be beneficial to have more formal analysis and documentation that market prices have a limited impact on optimal production schedules. This will provide additional comfort to stakeholders that this balance has, in fact, been reached. To this end, we asked MH to undertake the runs discussed in 3.8. These runs provide some evidence that changes in production schedules as a result of different price forecasts will have only a limited financial impact.

We also note that:

- Real-time trading decisions are made outside of the EMMA module of HERMES. EMMA provides suggested production schedules on a week by week basis, but operators can shape production within the next week using shorter-term planning models such as QSIM. QSIM helps operators manage forebay levels at dams on the Lower Nelson, giving MH additional flexibility in responding to market price shifts that occur within the next week. (Forebay refers to the water immediately upstream of a dam or control structure.)

- As noted elsewhere, MH sells a very limited proportion of its surplus energy beyond Day Ahead (DA) and Real Time (RT) markets. Hence, MH does not commit in advance to specific export quantities for the majority of its surplus energy production. This limits the financial risks that will accrue from shifts in production relative to plan.

3.7.3.2 Required Adjustments to Price Data

As noted above, significant adjustment is required to translate estimates of future MISO prices into estimates of the MISO prices that MH will actually receive for export sales (or of the MISO prices that MH will actually pay for purchased imports). MISO price data is most relevant for opportunity transactions, which generally occur in MISO day-ahead and real-time markets.

The need for adjustment arises from the following:

- Estimates of future MISO prices, whether from futures markets or purchased forecasts, are generally in the form of an average price over the peak periods within a month. For planning purposes, MH needs to have a means of modeling price variation within the month, both during peak and off-peak periods.

- Available price forecasts are generally for a key MISO hub, such as MINN (the Minneapolis node). MH transacts at the MHEB node, which is a node at the US/Canada border. MH needs to account for differences in prices between these hubs. MH has provided us with data that indicates that these nodal price differences can vary widely both across months and across hours within a month. In off-peak periods, MH transactions (and whether it is exporting or importing) appear to affect MISO prices and/or nodal differences, while these affects are much less pronounced during on-peak periods.

- In any particular period (such as a month), MH may be transacting in only a subset of the hours. MH traders will try to make transactions in the hours within the period that have the most favourable prices (i.e., the highest prices for sales and the lowest prices for purchases). However, because they do not have perfect foresight and because there may be limitations in tie-line or generating capacity, MH traders will not be able to transact consistently in the most favourable hours. Model assumptions must be (and are) calibrated to capture these affects.

- The EMMA model requires prices that are expressed in Canadian dollars and that take into account transmission losses that are charged against any particular transaction. Although the required adjustments are relatively straightforward, they introduce differences that need to be taken into account when comparing data from different sources.

We have had extensive discussions with MH staff on their approach for incorporating prices into their planning models and find that they apply significant care and due diligence in this process.

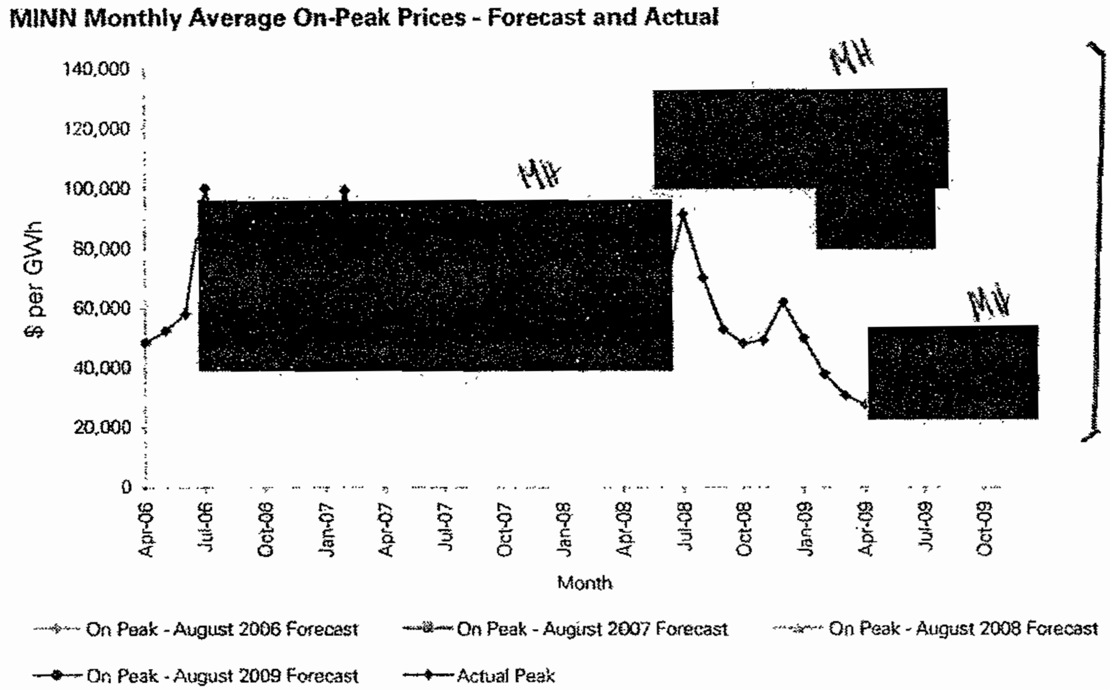
3.7.3.3 MH's Use of External Price Forecasts and Market Data

MH purchases price forecasts for MISO on a monthly basis. These forecasts provide projections of the MINN spot price in each month over the following year, averaged over the standard 5x16 on-peak period. MH uses these forecasts to update the pricing assumptions within EMMA. As MH sells the majority of its opportunity export sales in the cash market in MISO, the forecast of MISO spot price is an appropriate price signal for allocating MH surplus energy in and out of storage.

As noted earlier, however, MH management applies judgment when entering projected market prices into HERMES. Management may adjust prices downward if they believe the forecasts are too optimistic. Management reports that they did this in preparing the IFF for fiscal 2008/09.

Exhibit 3-6 indicates that this adjustment was warranted. Price forecasts provided by MH's pricing consultant in July 2008 for the following 12 months were substantially higher than the MISO prices that were actually observed. This is illustrated in Exhibit 3-6.

Exhibit 3-6: Forecast Versus Actual Prices



MH 2

Source: derived from Manitoba Hydro data

MH has not done an analysis of whether quoted futures prices would be a better predictor of future spot prices than the forecasts purchased from the external forecasting firm. One rationale for using quoted future prices as a forecasting tool is that they represent the actual preferences of market participants, as evidenced by these participants' willingness to enter into forward trades at the prices quoted. Factors that may reduce the effectiveness of futures prices as a basis for forecasting spot prices may include a lack of liquidity in the futures market and limits on the number of market participants willing to hedge their future production or demand. Comparing the effectiveness of alternative forecasting approaches would improve the confidence in MH's current price forecasting process.

3.7.4 Market Developments

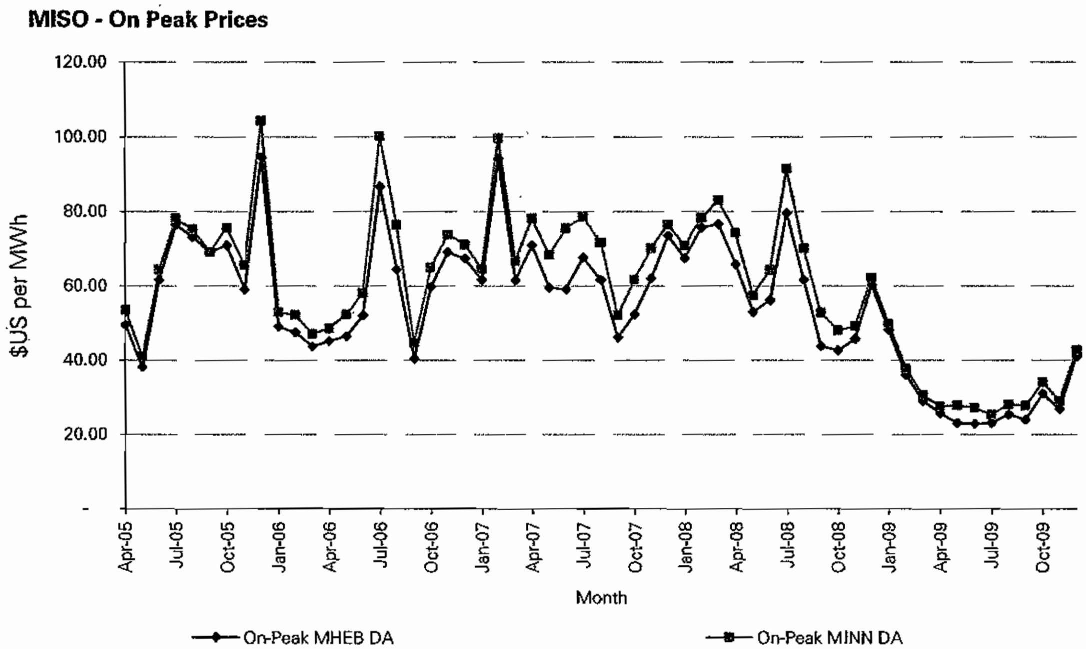
In this section, we review developments in electricity markets. These developments have a bearing on MH's proposed long-term contracts for the sale of power and on its approach to modeling operations.

Exhibit 3-7 indicates monthly on-peak electricity prices at two key nodes within MISO:

- The MHEB node at the Canada-US border where MH conducts most of its transactions in the spot market; and
- The MINN hub at Minneapolis, a major load point within MISO.

The MINN hub is a good reference point for the value of power to MH's major export customers.

Exhibit 3-7: On Peak Pricing at MINN and MHEB



Source: derived from Manitoba Hydro data

We have a number of observations with respect to price developments. These are outlined below.

3.7.4.1 Prices Have Declined

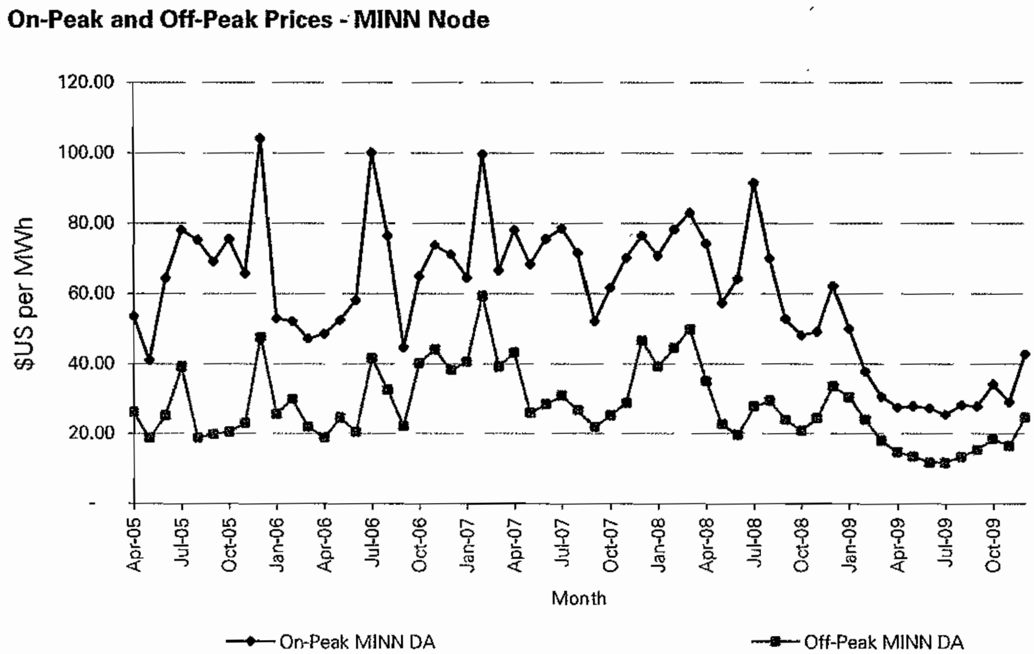
On-peak prices declined dramatically in 2009 relative to 2008. Average prices in 2009 are less than one-half of 2008 prices. The price decline reflects both a decline in natural gas prices, often the input fuel for generating plants on the margin, and a drop in electricity loads associated with the economic downturn.

The price decline highlights the risk for MH in relying entirely on spot markets for its electricity sales. Revenues could decline dramatically in the event of a market downturn. This is particularly a concern where revenues are used to support investment in new hydroelectric generation. The capital costs and associated debt charges as a result of new generation are fixed in advance. This suggests that a portion of the revenue should also be fixed in advance.

As noted elsewhere, aside from its long-term fixed contracts, MH sells much of the surplus energy associated with its new generating assets in a short-term basis.

As shown in Exhibit 3-8 below, prices in the off-peak period have fallen by less than prices in the on-peak period, based on monthly data for MINN. This has reduced the differences between peak and off-peak prices. This has reduced the ability of MH to profit from its hydroelectric storage capacity by taking advantage of such price differences.

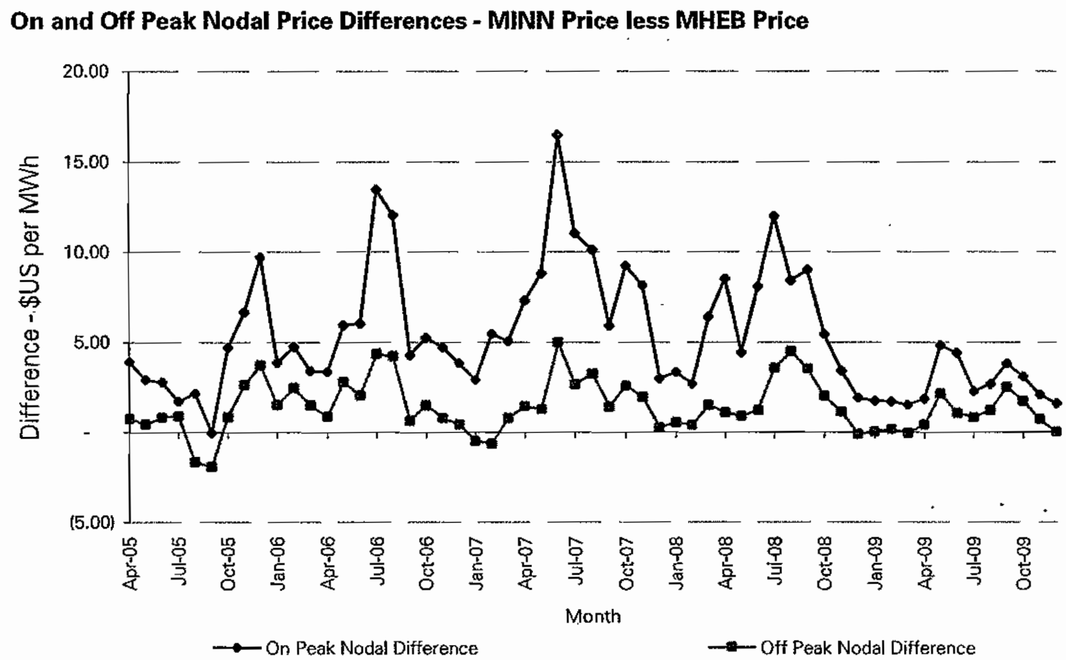
Exhibit 3-8: On-Peak versus Off-Peak Pricing at MINN



Source: derived from Manitoba Hydro data

The downturn in the electricity market has also reduced the spread between the MHEB and MINN hubs, both in on-peak and off-peak periods. Nevertheless, MHEB consistently trades at lower prices than MINN, which reduces the value that MH receives from opportunity sales. On a monthly average basis, the price discount at MHEB has been as high as $15 per MWh. Nodal price differences are illustrated in Exhibit 3-9 below. Nodal price differences result from transmission constraints in the MISO system. Excess supply at the MHEB node, which can result from MH export sales, will tend to reduce prices at MHEB relative to prices at MINN. Excess demand at MHEB (for example from MH import purchases) will tend to increase prices at MHEB relative to MINN. The presence of significant price differentials on an on-going basis suggests that transmission congestion is already an important issue for MH in its export transactions. Without an increase in transmission capacity, these price differences would likely increase in the future with increases in MH exports from new plant additions.

Exhibit 3-9: Nodal Price Differences – On and Off Peak



Source: derived from Manitoba Hydro data

3.7.5 Potential Errors in Price Inputs

In its report, the Consultant makes a general observation that prices used in the Generation Estimate report and those used in the HERMES runs are inconsistent, and therefore expose Manitoba Hydro to pricing error risks. The Consultant believes that these inconsistencies arise out of a lack of discipline or a lack of "checks and balances", and as the price inconsistencies have not been detected to date, they constitute a substantial financial risk for Manitoba Hydro.

KPMG has examined these assertions and we conclude, for the cases that we reviewed, the quoted data inconsistencies arise out of a mis-interpretation by the Consultant of the data that is being represented. This section describes our analysis.

Example #1 – Alleged price discrepancy between Generation Estimate reports and HERMES outputs.

On page 117 of the Consultant's Report of January 2008 second report, the Consultant notes a price discrepancy between certain prices shown in the Generation Estimate report for fiscal 2006/07, and those used in the supporting HERMES simulation runs. The apparent discrepancies relate to projected prices for April. The Consultant quotes a differential between peak and off-peak prices of **(-$13.27)** from the 2006/07 Generation Estimate report, and compares this to the price differential of **$38.49** observed in the "prices_risk.xls" file from the HERMES run of August 22, 2006.

The Consultant points to the differences in peak/off-peak price spreads and notes: "These are internal department errors in market pricing and fall short of best practices in control governance" *(Consultant's Report, January 2008, pg. 118).* The Consultant then goes on to note that they had observed "other vast price inconsistencies". *(Consultant's Report, January 2008, pg. 118)*

Based on a review of the circumstances regarding this assertion, we have found that the Consultant misinterpreted the various price figures. The figures quoted by the Consultant from the Generation Estimate report reflect actual average prices that were obtained by MH for import/export transactions in April 2006, taking into account the timing of these transactions within the peak and off-peak periods. In contrast, the prices quoted from the HERMES run reflect price inputs for April 2007, and were average time-weighted prices for on-peak and off-peak periods. In addition, there are differences in the definitions of on-peak and off-peak times for the numbers quoted. This is more fully documented below.

Detailed Findings

To reach this conclusion, KPMG has taken the following steps:

- Reproduced the findings of the Consultant to confirm the calculation methodology.

- Looked into the assumptions underlying the numbers that the Consultant is referencing to ensure consistency.

- Assessed the general applicability of making the comparisons that the Consultant is trying to make.

With respect to reproducing the findings of the Consultant, KPMG has observed the following:

[redacted]

NYC

[redacted]

- From this, KPMG calculates the same figure as the Consultant's **(-$13.27)** for the on-peak/off-peak differential.

[redacted]

NYC

[redacted]

- The calculated differential in the "price-risk.xls" file for these two prices is **$38.49**.

The mechanics of the Consultant's price calculation therefore appear to be correct.

With respect to assumptions underlying the two sets of numbers, we have consulted with Manitoba Hydro and note the following:

1. The numbers represent different things

The numbers quoted by the Consultant from the Generation Estimate Report are actual data for April 2006, while the numbers taken from the "prices_risk" report are forecast data for April 2007. Thus, the numbers from these sources are for periods that are one year apart, and are therefore not the exact same month. Even if they were for the same month and the same year, the prices would not be comparable. Prices in the "prices_risk" report represent forecasts of the average MISO price for the whole time duration of an individual strip. (A strip is a defined time period within the week. Strips are used in the modeling of demand fluctuations.) The "prices_risk" values for on-peak and off-peak are the time-weighted average prices for the strips making up the on-peak and off-peak time periods. (The definition of on-peak within this file corresponds to two time-strips, while off-peak corresponds to the remaining three time-strips.)

Prices in the Generation Estimate report, in contrast to those in the "prices_risk" file, represent the forecast average prices received or paid for sale and purchase transactions for the transaction amounts recommended by EMMA. (The exception is that prices for the months already passed within the 2006/07 period reflect actual rather than forecast data.) The prices forecast by EMMA for April 2007 with respect to on-peak spot market sales were $59.51/MWh. The forecast prices for off-peak spot purchases were $22.98/MWh. Thus, the forecast differential between peak and off-peak prices for April 2007 is $36.53, which is close to the differential of $38.49 observed by the Consultant within the "prices_risk" report.

The reason that the differentials are not exactly the same is the fact that prices forecast by EMMA reflect the distribution of prices within a strip as more fully outlined below.

2. Aggregation and mapping of a point price forecast to market curves

Each of the strips used in the EMMA module has a market curve that is modeled by blocks, and these are based on historical pricing patterns within the strip. Each projected transaction will have a forecast price that depends on the projected point along the curve that a transaction occurs. In particular, if only a few transactions are projected within a strip, these might show a much higher price (e.g. for sales) because the model accounts for MH's ability to concentrate these sales in a few high-priced hours. Similarly, the timing of purchase transactions may be constrained to a few high-priced hours because of transmission constraints or other capacity conditions (e.g. the need to meet demand fluctuations across the strips making up the on-peak or off-peak periods and/or within a particular strip making up these periods.)

As noted above, the Consultant observed off-peak purchases of 7 GWh at a price of $50.22/MWh in April 2006. It is interesting to note that, for the same month, the Generation Estimate report showed that Manitoba Hydro had forecast 282 GWh of off-peak *sales* at a price of $15.41 (in addition to the similar amount of *on-peak* sales also noted). On a volume and total dollar basis, these sales are much more important significant than the small amount of purchases. Having off-peak exports and imports in the same month does not indicate any operational errors, but rather highlights the need to manage load variation and operating constraints on a real-time basis. More generally, it should be noted that it can be misleading to look at individual data points in isolation.

3. Aggregation of price strips to on-peak and off-peak

Different assumptions also underlie the definition of on-peak and off-peak with respect to how the price data in the strips is aggregated. The Consultant uses an on-peak definition of 5x16 hours, while the EMMA module uses 6x16 (adding Saturday to the calculation of peak hours).

Based on these observations, KPMG notes that the values reported in the Generation Estimate report cannot be compared to numbers in the "price_risk.xls" file. It is therefore reasonable that numbers reported may not match even if they are compared for the same time periods. The fact that these numbers are different does not in any way indicate errors in the HERMES optimization process.

Example #2 – Alleged Incorrect Peak Off-Peak Correlations

The Consultant asserts that pricing inputs to the HERMES model incorrectly assumed a 100% correlation between peak and off-peak prices. We have reviewed pricing inputs to HERMES runs in the fall of 2006 and found that peak and off-peak price inputs for fiscal 2007/08 had, in fact, a correlation of about 0.59 to 0.62, depending on whether price assumptions for import purchases or export sales are used.

Actual market data, obtained *ex post*, show correlations of 0.81 to 0.84 for the MHEB node (Exhibit 3-10). Correlations were calculated from monthly average prices, rather than from hourly prices. This contrasts to the Consultant's assertion that MISO data show correlations at 40% at the MISO node.

Exhibit 3-10: Peak and Off-Peak Correlations in 2007/08 at MHEB Node

	Peak–Off-Peak Correlations
Real Time	0.81
Day-Ahead	0.84

Source: data from MH and KPMG Analysis

3.7.6 Data on Historical Flow Record

The Consultant expresses concerns that the hydrological data used by MH in its planning processes is flawed. The key concerns relate to the quality of the historical data that are used. As you go farther back in time, the number of gauging points for which data are available is reduced and, accordingly, estimates of overall flow volumes become less reliable. Overall flow estimates for the historical period require interpolations and adjustment of the data from those gauging points that are available.

It is reasonable to have concerns about the quality of hydrologic data. However, it is not clear what MH should be doing differently as a result of these concerns. MH cannot change the fact that gauging data is unavailable. It seems reasonable to attempt to estimate water flows on the basis of the data that is available, in part to get a sense of longer term trends.

The Consultant identifies a number of years which mark the addition of gauging data and hence improvements in data quality: 1942, 1974, and 1989. We examined the impact of using each of these dates as starting points for the historical record rather than using 1912, which is the starting point used by MH in SPLASH. To do this analysis, we used aggregate data on overall water flows as indications of potential hydroelectric production.

For the full historical record from 1912, average flow measured as at Conawapa is 113.11 kcfs. Using different starting points has the following impact:

- Starting at 1942 results in a flow average of 116.13 kcfs, which is 2.7% higher than the estimate derived from the full record.
- Starting in 1974 results in a slightly lower average flow figure of 113.06 kcfs, or 0.04% less.
- Starting in 1989 results in a flow average that is 0.72% higher than that for the full period.

These figures are summarized in Exhibit 3-11.

Exhibit 3-11: Impact of Start Date on Calculated Average Flow

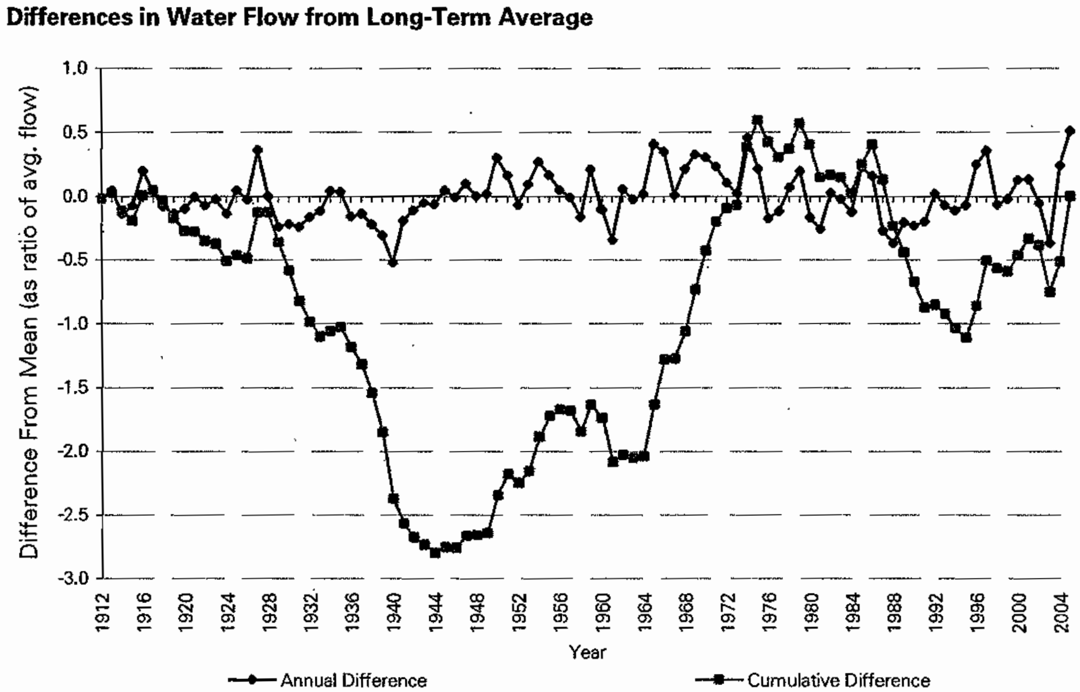
Beginning Year	Calculated Average Flow @ Conawapa (kcfs)	Difference from Full Data Set
1912 *(Full Data Set)*	113.11	0%
1942	116.13	+ 2.7%
1974	113.06	- 0.04%
1989	113.93	+ 0.72%

Source: derived from Manitoba Hydro data

Excluding data prior to 1942 has, in particular, a large impact on calculated average flows. Estimated flows in the period prior to 1942 were low relative to the average over the full flow period. Including data prior to 1942 adds an element of conservatism, even if they are based on less extensive gauging data.

Another way of looking at the data is to graph the difference between annual flows and the long-term average flow over the 94 year-period. Differences from the average flow can be graphed on both an annual and cumulative basis. This is done in Exhibit 3-12 below.

Exhibit 3-12: Annual Flows – Difference from Long-Term Mean



Source: derived from Manitoba Hydro data

The large cumulative difference in water flows (from the mean level of flows) in the period leading up to 1944 highlights the relatively low water flows in the first part of the past century.

3.7.6.1 Operational Risk

The Consultant quotes risk figures associated with MH flow data as follows:

"There is a degree of operational risk in the median/average forecasting process, alongside the statistical adjustments, that needs to be accounted for in risk capital adequacy process.

"Using the modeling discrepancies from utilizing historical averages and the Hermes flows, has operational model discrepancies measured to the forecasted P&L results in an order of magnitude risk of $50 MM to Hydro's forecasted P&L." (*Consultant Report, December 2006, p.21*).

We have interpreted this text to mean there is uncertainty in MH's earnings that is associated with uncertainty over the true underlying value for expected water flows. To the extent flow data over or under-estimate the true underlying average value of water flows, MH's earnings are consistently under or over-forecast. We have further interpreted the above quote to mean that MH needs to set aside reserves to cover this uncertainty in its capital adequacy process.

It is certainly true that expected earnings will be under or over-stated to the extent that historic water flow data provide an incorrect view of expected future water flows. Based on a number of simplifying assumptions, we could produce an estimate of earnings uncertainty as a result of uncertainty in water flow data that is similar to that reported by the Consultant. We do not know, however, if the approach that we used was similar to that used by the Consultant.

Whatever assumptions were used to calculate the Consultant's figure of $50 million, a more important question relates to its practical significance. If we are correct in our assumption that the figure relates to earnings risk, it is not clear what MH needs to do as a result of this risk measure. MH cannot change actual future flow amounts, even if it has incorrect estimates of their long-term expected values based on imperfect gauge data. MH could increase its risk capital, adjust rates, and/or alter its calculation of Dependable Energy. However, none of these steps will directly influence the amount of energy that MH can or will produce from future water flows.

3.7.6.2 Longer Term Records

A broader question relating to flow data is the representativeness of the past 97 years for the purpose of forecasting likely future flows. Two issues are relevant to consideration of this matter:

1. There is some evidence that worse droughts have occurred in MH's prairie watershed in the centuries preceding the past one. This issue was recently raised in a McCullough Research paper (*McCullough Research, Review of the ICF Report on Manitoba Hydro Export Sales, December 2, 2009, pg. 5*).

2. Climate change may change future water flow patterns relative to those of the past.

These issues may be more significant to MH's financial planning process than imperfections in available flow data.

In his paper, McCullough indicates that data from tree ring samples suggest that dependable energy might be 400 MWa lower than the 2,400 MWa figure calculated by MH in its power resource plans. Such long-term data suggests that it may be prudent to examine water flows that are lower than the historical record as part of some scenario analyses.

Flow estimates derived from tree-ring data would involve many more estimates and assumptions than were used to derive MH's 94 year hydrological record. As noted elsewhere, the Consultant had concerns about the validity of some of the estimates that MH uses in deriving its existing historical flow record. As a result, it is probably more appropriate to use water flow scenarios based on tree-ring data for risk analyses than as the basis of base case financial forecasts.

3.7.6.3 Practices at Other Utilities

For long-term forecasting and planning purposes, it is reasonable to rely on historical flow data for estimating dependable energy. We found a number of other major North American hydroelectric utilities that use a similar practice. Although other utilities may consider the potential impact of flows outside the historical record in specific runs undertaken to support scenario analyses, they do not appear to use such cases in their base case financial forecasting processes.

MH management have noted that:

- There is no indication to date that the long-term average flow is decreasing.

- Any impact from climate change on future average flows is likely to occur relatively gradually.

- Climate change may have more impact on future customer loads than on future water flows. To the extent winter heating loads are decreased, these impacts will help to offset any decreases in energy available that result from changes in water flow patterns.

Details on forecasting practices at some other major utilities are provided below.

BC Hydro

BC Hydro uses a 60-year flow record to establish firm energy available from its hydroelectric system. A BC Hydro document notes:

"Firm energy for the hydroelectric system is the energy capability of the system under the most adverse sequence of stream flows within the adopted period of historical record (critical water). Currently the most adverse set of stream flows is that which occurred from October 1940 to April 1946." (*BC Hydro 2006 Integrated Electricity Plan and Long Term Acquisition Plan, p. 29*).

During the course of an oral hearing, counsel for the British Columbia Utilities Commission (BCUC) suggested that the date points of 1945 and 1946, when evaluated against a normal distribution, appear as statistical outliers and should therefore be removed. Removal of these data points would increase calculated firm energy by almost 2,000 GWh/year (from 42,600 GWh). BC Hydro resisted this proposal, noting that this would increase the risk of energy shortfalls, and there was no basis to remove or modify this portion of the data set.

Bonneville Power Administration

In its risk assessment process, the Bonneville Power Administration (BPA) uses hydro generation data estimated from monthly streamflow patterns observed from October 1928 through September 1978. This provides a 50-year record. As with MH models, data are taken in sequence in the risk simulation process. Different start points are used to generate different test flow patterns (*Bonneville Power Administration, Risk Analysis Study, WP-07_FS-BPA-04, July 2006, p. 13*).

Puget Sound Energy

As part of its Integrated Resource Plan, Puget Sound Energy (PSE) assumes that hydropower generation is based on average stream flows for the 50 historical years of 1929 to 1978. Monthly average historical data is used to account for seasonal variability in hydropower availability. *(Puget Sound Energy, 2009 Integrated Resource Plan, Appendix I – Electric Analysis, p. I-15).*

US Bureau of Reclamation

For its Environmental Impact Statement for the Lower Colorado Basin and related dams, the US Bureau of Reclamation forecasts its future inflows using the existing historical record of natural flows from 1906 through 2005. The historical data is run through a resampling technique that the Bureau refers to as the "Indexed Sequential Method" (ISM). The ISM sampling approach appears to be identical to that used at MH. The simulation program cycles through the historic water flow record by using different flow years for the initial year. Subsequent flow years are then assumed in sequence. Whenever the end of the flow record is reached during the process of creating a particular run, the model returns to the initial year of data to continue the process. The Bureau notes: "The result of the ISM is a set of probabilistic future hydrological conditions, based on the hydrological variability over the historical record. ISM is well-documented and has been widely accepted by Colorado River stakeholders." *(Final EIS – Colorado River Interim Guidelines for Lower Basin Shortages and Coordinated Operations for Lake Powell and Lake Mead).*

In its Final EIS, the Bureau acknowledges that tree-ring data show that hydrologic variability, over a long period of time, is greater than that observed in the gauged record. The Bureau therefore uses such paleoclimatic data as the basis of some sensitivity analyses. It notes:

"Although paleoclimatic information may not represent future climate scenarios, this information may be useful in framing assumed variability in future hydrologic sequences, particularly with respect to drought potential." *(Final EIS – Colorado River Interim Guidelines for Lower Basin Shortages and Coordinated Operations for Lake Powell and Lake Mead, p.4-13.).*

3.7.7 Lake Level Balances

In its first report, the Consultant observed a decline in projected lake level balances as at April 1st, 2007 in HERMES model runs done in the fall of 2006 *(Consultant's Report, December 2006, p.8)*. The Consultant correctly observes that declines in lake level balances as at April 1st, 2007 imply a reduction in expected MH earnings in fiscal 2007/08. This reflects the lower availability of energy in storage at the beginning of the year, hence lower than expected export sales and/or increased reliance on thermal generation and imports. In addition, there is a potential increase in earnings volatility, since lower lake level balances imply less "cushion" to absorb potential future variances in water inflows.

It is important to note that HERMES runs provide a suggested production schedule that optimizes earnings, taking into account all production constraints and costs, expected inflows, and market prices in different periods. Lake level balances at any particular point are an output, rather than an input, to the HERMES optimization process. (Lake level balances on controlled reservoirs are, however, subject to constraints that set minimum, or floor, levels to ensure reliability targets are maintained.) Accordingly, changes in lake levels in HERMES runs reflect a change in the level that is estimated as optimum, rather than a specific management decision.

The Consultant reports a MTM valuation impact, as a result of changes in lake levels, of negative \$78 million between the period August 4th, 2006 and November 13th, 2006. We have not been able to duplicate the Consultant's exact calculation but it appears broadly plausible. We have been able to obtain a similar number making some simplifying assumptions.

The Consultant had a concern that the IFF for 2007/08, which was produced in late summer of 2006, was not updated in late fall to reflect the change in outlook. This concern was reasonable. We note that MH now produces a report titled "Supply Value at Risk Variance Analysis", that provides management with updates to the IFF when required as a result of changes in the forecast outlook. In addition to providing updated forecasts at median flows, it also indicates results under low and high-flow scenarios. It thus provides an indication of the range of possible outcomes taking into account potential water flow variation and updated lake level balances.

3.7.8 Lake Level Balance Discrepancies

In its first report, the Consultant alleges that HERMES runs made during 2006 had, on a number of occasion, lake level balances in the start of fiscal 2007/08 that were different from, and therefore disconnected from, ending lake level balances in fiscal 2006/07. We have reviewed the runs provided to the Consultant and observed these types of discrepancies.

MH's response to these discrepancies is as follows:

- The files for fiscal 2007/08 were provided at the request of the Consultant and were not used for operations planning or for financial forecasting.

- Runs for the next fiscal year (e.g., data for 2007/08 produced during runs done in 2006) are only used once a year to provide input to the official Generation Estimate Report. This report is generally prepared in August of each year. For these runs, ending and starting lake levels are matched at the time of final submission. Future fiscal year runs produced at other times of the year, and thus not used in preparation of the Generation Estimate report, are not used for operations planning purposes.

Further to MH's response, we conducted an analysis on the financial impact of the lake level discrepancies. We examined starting and ending lake levels in the 2006

Generation Estimate Report. Exhibit 3-13 summarizes lake levels as published in the 2006 Generation Estimate report. There are discrepancies in lake levels on eight of the 29 lakes modeled. The discrepancies are generally small. By applying factors representing the change in water storage with lake level and the amount of energy per unit of water stored, we estimate that the total discrepancy in this year amounted to about 20,000 MWh. Assuming a market value of $50 per MWh, this amounts to a potential understatement of revenues post-2006/07 of $0.98 million, because of "lost" water. The amount of the discrepancy is small in light of total average storage at fiscal year end, measured over a period of 26 years, of about 10 TWh, or 10 million MWh. Thus, the discrepancy is less than 0.2 percent of total water in storage.

Exhibit 3-13: Analysis of Lake Level Discrepancies – April 1st, 2007

Elevation (ft)	2006/07 Ending	2007/08 Starting	Difference	Storage/ft kcfs*days/ft	Prodn Coeff. MW/kcfs	MWh
Limestone Forebay	278.50	278.50	-	[redacted]	7.90	-
Long Spruce Forebay	361.30	361.30	-	[redacted]	14.10	-
Stephens Lake	459.60	459.60	-	[redacted]	21.55	-
Split Lake	549.81	549.58	(0.23)	38.8	21.55	(4,618)
Thompson Seaplane Base	619.28	619.28	-	[redacted]	21.55	-
Kelsey Forebay	603.50	603.50	-	[redacted]	25.40	-
Sipiwesk Lake	611.27	611.19	(0.08)	98.5	25.40	(4,801)
Cross Lake	680.67	680.65	(0.02)	92.0	25.40	(1,122)
Jenpeg Forebay	705.10	705.10	-	[redacted]	27.50	-
Lake Winnipeg	712.52	712.52	-	[redacted]	27.50	-
Cedar Lake	834.00	834.00	-	[redacted]	36.29	-
Pine Falls Forebay	751.66	751.66	-	[redacted]	30.17	-
Great Falls Forebay	811.74	811.74	-	[redacted]	33.96	-
Lac Du Bonnet	835.68	835.68	-	[redacted]	35.55	-
Natalie Lake	899.30	899.30	-	[redacted]	39.67	-
Slave Falls Forebay	933.20	933.20	-	[redacted]	41.65	-
Pointe Du Bois Forebay	980.00	980.00	-	[redacted]	44.76	-
Sand Lake	1,036.80	1,036.80	-	[redacted]	44.76	-
Lake Of The Woods	1,057.60	1,057.60	-	[redacted]	44.76	-
Rainy Lake	1,105.15	1,105.15	-	[redacted]	44.76	-
Namakan Lake	1,113.25	1,113.25	-	[redacted]	44.76	-
Lac La Croix	1,182.69	1,182.28	(0.41)	17.5	44.76	(7,689)
Umfreville Lake	1,043.90	1,043.90	-	[redacted]	44.76	-
Separation Lake	1,046.02	1,046.03	0.01	20.9	44.76	225
Ball Lake	1,050.88	1,050.87	(0.01)	22.4	44.76	(240)
Pakwash Lake	1,135.67	1,135.67	-	20.9	44.76	-
Lac Seul	1,164.00	1,164.00	-	[redacted]	44.76	-
Lake St Joseph	1,220.49	1,220.47	(0.02)	62.7	44.76	(1,348)
Laurie River Forebay	212.50	212.50	-	[redacted]	28.21	-
	29			8		
Total MWh						**(19,592)**
Value per MWh						50
Total $s						**(979,597)**

Source: derived from Manitoba Hydro data

We checked for similar discrepancies in the Generation Estimate reports supporting IFF processes for subsequent years, as indicated in Exhibits 3-14 and 3-15. As at April 1st, 2008, discrepancies were even smaller than in 2007. At an estimated 2,800 MWh, the discrepancy has a financial value of $140,000, at an assumed $50 per MWh value for electricity. The discrepancy at April 1st, 2009 was negligible. Errors, in addition to being small, have been significantly reduced over time.

Exhibit 3-14: Analysis of Lake Level Discrepancies – April 1st, 2008

Elevation (ft)	2007/08 Ending	2008/09 Starting	Difference	Storage kcfs*days/ft	Prodn Coeff. MW/kcfs	MWh
Limestone Forebay	278.50	278.50	-	[redacted]	7.90	-
Long Spruce Forebay	361.30	361.30	-	[redacted]	14.10	-
Stephens Lake	459.60	459.60	-	[redacted]	21.55	-
Split Lake	550.01	550.01	-	[redacted]	21.55	-
Thompson Seaplane Base	616.99	616.99	-	[redacted]	21.55	-
Kelsey Forebay	603.50	603.50	-	[redacted]	25.40	-
Sipiwesk Lake	611.38	611.38	-	[redacted]	25.40	-
Cross Lake	681.35	681.35	-	[redacted]	25.40	-
Jenpeg Forebay	705.10	705.10	-	[redacted]	27.50	-
Lake Winnipeg	714.00	714.00	-	[redacted]	27.50	-
Cedar Lake	837.00	837.00	-	[redacted]	36.29	-
Pine Falls Forebay	751.66	751.66	-	[redacted]	30.17	-
Great Falls Forebay	811.74	811.74	-	[redacted]	33.96	-
Lac Du Bonnet	835.68	835.68	-	[redacted]	35.55	-
Natalie Lake	899.30	899.30	-	[redacted]	39.67	-
Slave Falls Forebay	933.20	933.20	-	[redacted]	41.65	-
Pointe Du Bois Forebay	980.00	980.00	-	[redacted]	44.76	-
Sand Lake	1036.75	1,036.75	-	[redacted]	44.76	-
Lake Of The Woods	1058.50	1,058.50	-	[redacted]	44.76	-
Rainy Lake	1105.15	1,105.15	-	[redacted]	44.76	-
Namakan Lake	1113.25	1,113.25	-	[redacted]	44.76	-
Lac La Croix	1182.75	1,182.75	-	[redacted]	44.76	-
Umfreville Lake	1043.90	1,043.90	-	[redacted]	44.76	-
Separation Lake	1047.18	1,047.18	-	[redacted]	44.76	-
Ball Lake	1051.74	1,051.74	-	[redacted]	44.76	-
Pakwash Lake	1135.67	1,135.67	-	[redacted]	44.76	-
Lac Seul	1165.50	1,165.50	-	[redacted]	44.76	-
Lake St Joseph	1221.72	1,221.92	0.20	62.7	44.76	2,808
Laurie River Forebay	212.50	212.50	-	[redacted]	28.21	-
	29			1		
Total MWh						**2,808**
Value for MWh						50
Total $s						**140,394**

Source: derived from Manitoba Hydro data

Exhibit 3-15: Analysis of Lake Level Discrepancies – April 1st, 2009

Elevation (ft)	2008/09 Ending	2009/10 Starting	Difference	Storage kcfs*days/ft	Prodn Coeff. MW/kcfs	MWh
Limestone Forebay	278.50	278.50	-	[redacted]	7.90	-
Long Spruce Forebay	361.30	361.30	-	[redacted]	14.10	-
Stephens Lake	459.60	459.60	-	[redacted]	21.55	-
Split Lake	550.44	550.44	-	[redacted]	21.55	-
Thompson Seaplane Base	619.25	619.25	-	[redacted]	21.55	-
Kelsey Forebay	603.50	603.51	0.01	3.067	25.40	0.78
Sipiwesk Lake	611.28	611.28	-	[redacted]	25.40	-
Cross Lake	681.39	681.39	-	[redacted]	25.40	-
Jenpeg Forebay	705.10	705.10	-	[redacted]	27.50	-
Lake Winnipeg	714.07	714.07	-	[redacted]	27.50	-
Cedar Lake	832.25	832.25	-	[redacted]	36.29	-
Pine Falls Forebay	751.66	751.66	-	[redacted]	30.17	-
Great Falls Forebay	811.74	811.74	-	[redacted]	33.96	-
Lac Du Bonnet	835.68	835.68	-	[redacted]	35.55	-
Natalie Lake	899.30	899.30	-	[redacted]	39.67	-
Slave Falls Forebay	933.20	933.20	-	[redacted]	41.65	-
Pointe Du Bois Forebay	980.00	980.00	-	[redacted]	44.76	-
Sand Lake	1036.50	1,036.50	-	[redacted]	44.76	-
Lake Of The Woods	1057.71	1,057.71	-	[redacted]	44.76	-
Rainy Lake	1105.15	1,105.15	-	[redacted]	44.76	-
Namakan Lake	1113.25	1,113.25	-	[redacted]	44.76	-
Lac La Croix	1182.63	1,182.63	-	[redacted]	44.76	-
Umfreville Lake	1043.90	1,043.90	-	[redacted]	44.76	-
Separation Lake	1047.77	1,047.77	-	[redacted]	44.76	-
Ball Lake	1052.81	1,052.81	-	[redacted]	44.76	-
Pakwash Lake	1135.34	1,135.34	-	[redacted]	44.76	-
Lac Seul	1164.35	1,164.35	-	[redacted]	44.76	-
Lake St Joseph	1220.79	1,220.79	-	[redacted]	44.76	-
Laurie River Forebay	212.50	212.50	-	[redacted]	28.21	-
	29			1		
Total MWh						**0.78**
Value for MWh						50
Total $s						**39**

Source: derived from Manitoba Hydro data

3.7.9 Production Coefficient Data

The Consultant alleges that there are differences between HERMES and SPLASH in the production coefficients used. (*Consultant Report, December 2006, p. 23*) Further, the Consultant asserts that the SPLASH model has a superior (or "visibly more robust") approach to specifying production coefficients.

Production coefficients are the numerical parameters used in the calculation of power production. For each plant and for a particular level of output, the production coefficient captures the relationship between water flow and electricity generation as follows:

Electricity Output = Production Coefficient (MW/kcfs) x Water Flow (kcfs)

The appropriate "Production Coefficient" to use for any facility varies over time as a result of a number of effects.

The head at each generating station decreases with increasing flow through the plant, since increasing flow results in increasing elevation of the tailwater level. This is a particularly important effect for MH stations relative to those of many other hydroelectric utilities because MH has a system with relatively large water volumes but low heads. Relatively small increases in tailwater level can result in relatively large decreases in output.

The efficiency of the generating turbine varies with water flow (efficiency is calculated as the actual electricity output versus the theoretical maximum based on water flow and head). The efficiency can vary from about 78% to 92%, and may peak at flow that is 70% to 80% of the maximum flow without spillage.

Power flow can be characterized through the following engineering relationship:

P (Power) = [Fb – Tw (DSE, Q_T)] x e (Head, Q_P)/11.8[4] x Q_P

Where:

Fb = forebay elevation

Tw = tailrace elevation (a function of downstream elevation (DSE) and total water quantity (Q_T)

e = efficiency [a function of Head (which equals forebay elevation (Fb) less tailrace elevation (Tw)) and Q_P, which is the water quantity through the powerhouse.]

Quantity through the powerhouse (Q_p) differs from the total water quantity (Q_T) by the amount of spill.

The relationship above on power flow can be simplified into the following relationship:

Electricity Output = Production Coefficient (MW/kcfs) x Water Flow (kcfs)

[4] *11.8 is a constant that applies when imperial units of flow and head are used.*

In this simplified representation, the Production Coefficient thus captures the following elements of the detailed equation:

$[Fb - Tw\ (DSE, Q_T)] \times e\ (Head, Q_P)/11.8$

The simplified representation is used within the HERMES and SPLASH models in order to facilitate the calculation of results within a Linear Programming ("LP") framework. In applying this simplified equation, however, MH needs to account for the fact that the Production Coefficient varies, as discussed above, with water flow. Thus, the LP algorithm calculates results using an iterative process. An initial estimate (based upon maximum head which minimizes reservoir releases) for the production co-efficient is used to calculate an initial estimate of flow and output. These estimates are refined until production coefficients and flow converge to numbers that are consistent with the production coefficient function.

Data provided to us by MH show that the Production Coefficient for a representative station increases rapidly with small amounts of flow from a value that is near zero, but over the usual range of production can vary by up to 25% of its maximum value. Thus, it is clearly important, as the Consultant asserts, that an appropriate value for the Production Coefficient be used within the planning models.

3.7.9.1 Findings

Based on our discussions with MH personnel and a review of the materials they provided, we are satisfied that they have taken appropriate care and due diligence in modeling production coefficients. They take into account plant efficiency when attempting to optimize the scheduling of their hydroelectric stations.

There may appear to be differences in production coefficients between the models as a result of the optimization approach used within each model. This is discussed further in the section below.

3.7.9.2 Differences between HERMES and SPLASH

There are valid reasons why coefficients observed within HERMES and SPLASH for the same period may be different.

As discussed elsewhere, HERMES takes a more "granular" approach to modeling time. Within a three-month time horizon, HERMES generally operates with a weekly time-step. Each one-week period is divided into five sub-periods. After three months, HERMES moves to a monthly time step, also with five sub-periods.

In contrast, SPLASH operates with a monthly time step over its full forecasting range, and each such month is divided into peak and off-peak periods.

In summary, HERMES has more detail with respect to its modeling of the system. Differences in forecast water flow among time periods will cause the production coefficient that should be assumed in each such time period to vary. SPLASH will use an average value for a broader period, while HERMES will use values appropriate to each sub-period.

The Consultant alleges that the "problem referred to by engineers with the HERMES systems is that it uses a uniform plant averaging which does not take into consideration accurately the degrading incremental slope" (*Consultant Report, January 2008, p.70*). In its first report, the Consultant alleges that SPLASH and HERMES use different assumptions with respect to plant production coefficients (*Consultant Report, December 2006, p. 23*).

Based on our discussions with operators of the HERMES system, a review of documentation with respect to model structure, and a review of the outputs of this model, we believe that the Consultant's characterization is inaccurate. It appears that modeling within HERMES does carefully take into account changes in production coefficients with flow. This may not have been apparent to the Consultant from the outputs that it reviewed.

In comparing HERMES and SPLASH, it is important to note that neither are used in the "fine tuning" of production decisions. Thus, whatever these models predict, MH operators will adjust actual schedules to meet load variation within the time steps, to optimize plant gate settings, and to address flow constraints. Both HERMES and SPLASH are not sufficiently detailed or real-time to mirror actual operations. Hence, actual production coefficients achieved will reflect considerations beyond HERMES and SPLASH.

3.7.9.3 Estimates of Error

The Consultant calculates a $2.2 million difference between HERMES and SPLASH in outputs for a representative winter month. (*Consultant Report, January 2008, p.67*).

This amount is the product of the following inputs:

[redacted]

NYC

[redacted]

[redacted]

[redacted]

NYC

The Consultant then multiplies this figure by 12 months to obtain an annual "operational error" of $26.4 million.

As discussed above, it appears that MH takes considerable care to calculate production coefficients. Accordingly, we do not believe that there is a consistent error of the magnitude noted. Nevertheless, we consider the potential implications of any possible errors in the section below.

3.7.9.4 Impact of Forecast Error

Even if we were to assume that the HERMES model did have incorrect assumptions about underlying equipment performance, and these in turn yielded incorrect estimates of future production, it is not clear that these errors would result in any actual financial losses for MH. Actual production will ultimately reflect the true underlying coefficient and, in general, there will be no loss in actual electricity production relative to that which was achievable. MH will have, however, been out in its forecast. We do not wish to minimize the undesirability of producing incorrect forecasts, but do want to be clear on the actual effects of the error. Hence, we will elaborate on this conclusion below.

If coefficients in HERMES were, in fact, incorrect, MH could prepare an incorrect forecast of future production at a given facility. Differences in actual results versus forecast would result from either:

- More or less water used than forecast to produce a given amount of electricity output.

- More or less electricity production than forecast for a given amount of water flow.

At the time of actual production, the scenario above that would apply will depend on whether system operators hold electricity production or water flow to the values in the forecast.

In the event that operators hold production constant, and less water was used than forecast to produce a given amount of electricity, it is conceivable under certain circumstances that the remaining water could not be stored effectively because of limitations in reservoir levels and would ultimately be "spilled". Thus, errors in coefficients could potentially, in certain circumstances, lead to direct losses. Without such limitations leading to spillage, however, errors in the forecast would simply mean either that more or less water is used, or more or less electricity is generated. Since actual production will reflect the actual physical characteristics of the plants, however, there is no shortfall relative to what is actually achievable, only a shortfall relative to a flawed forecast.

To the extent that production coefficients are incorrect in their forecast, financial losses could also accrue because of sub-optimization. Thus, incorrect coefficients could cause HERMES to suggest a production schedule that allocates production across time periods in a sub-optimal manner. This reflects the fact that HERMES takes into account production coefficients, among other factors, in the optimization process. However, it is reasonable to assume that this risk would be small. Production schedules are much more likely to be affected by forecasts of water flow, power prices and load variation than by the impact of slight, and possibly incorrect, differences in production coefficients across time periods.

We note, however, that this discussion is purely theoretical, because we have seen no evidence that production coefficients are, in fact, inaccurate.

We also do not want to imply that consistent errors in forecasting, if present, would be unimportant. They would represent a concern that should be addressed. However, we have seen no evidence that there are systematic errors in the forecasting undertaken.

In this context, it should be noted that EMMA runs provide MH management with suggested parameters for operation of the MH system, including suggested schedules for the release of water. Each EMMA run provides a suggested production schedule for the entire time horizon of the run.

MH management takes this suggested schedule into account when making actual production decisions, but actual system operation will differ from the suggested schedule for the following reasons:

- From a particular EMMA run, it is the suggested production in the next period that is most relevant for operational planning. Since EMMA is run on a weekly basis, managers making operational decisions further in the future will instead rely on subsequent EMMA runs to inform their decision making. In other words, EMMA runs evolve over time, and subsequent runs will incorporate new information.

- Decisions on the use of certain storage facilities are actually made on a daily basis, and reflect influences other than just the current EMMA run. For example, forebay storage is managed to optimize hourly production and to capture or take advantage of price arbitrage opportunities within the day (e.g., peak/off-peak differentials). Thus, MH can respond to market opportunities that appear in the short term but that are not captured in the most recent EMMA model run. Hence, additional value may be obtained from storage than is forecast by EMMA.

- Actual decisions on production are influenced by operational considerations that may not be reflected in EMMA. Actual water releases are influenced by a variety of factors, including consideration of impacts on local community groups and operational issues not captured in model logic. These factors may cause adjustments to the schedules suggested by MH's modeling tools.

The significance of the above factors is that the actual value achieved from storage is not just a function or product of the modeling tools used.

3.7.10 Storage Option Modeling Techniques

The Consultant alleges that HERMES and SPLASH entail differences in the modeling of option value associated with storage. Further, the Consultant states that "an annualized option value difference of $14.2 million annually is observed between the two systems". The SPLASH system "utilizes a better and more efficient valuation of storage." (*Consultant's Report, December 2008, p. 27*)

To address this assertion, we will first consider the nature of the two systems. When we discuss HERMES, we are generally referring to EMMA (Energy Management Model) within HERMES.

Both EMMA and SPLASH use linear programming routines to identify optimal production decisions under input scenarios that specify loads and water resources, in addition to other production variables, over a planning horizon. Neither EMMA nor SPLASH explicitly address uncertainties in input variables during their optimization routines. Thus, loads and water resources in any particular period are both handled as fixed inputs by the linear programming algorithms. The models do not allow modeling of input variables as stochastic functions (with the exception of the 94 flow years that are modeled in SPLASH). As such, neither model identifies the "option value" of storage.

By option value, we mean the additional value associated with an asset as a result of its operating flexibility, in an environment where there is uncertainty about future events. Rather, the models consider and optimize the value of storage under the expected regime for water flows, market prices, load and other factors. EMMA and SPLASH produce estimates of revenue and net production cost for the overall system that reflect the value of storage capability. It is not necessary for the models to identify an explicit "storage option value" for the purpose of production scheduling.

The EMMA system is used in the planning of operations over a short-term horizon, while SPLASH is used over a longer-term horizon to plan facility additions. Because EMMA is used to support current operational decisions, it has more detail, as discussed earlier, with respect to system operations:

- EMMA uses a weekly time-step over a three-month horizon, and then a monthly horizon thereafter. SPLASH, in contrast, models monthly periods for the full projection period.

- EMMA divides weekly or monthly time-steps into five periods. Because it divides the time-step into five increments, EMMA has more detail with respect to load and price variation within each time-step than SPLASH, which simply divides each monthly time-step into peak and off-peak periods.

- The additional detail within EMMA also means that it has much more detail with respect to system constraints, such as tie-line flows and plant capacity. This may result in a lower forecast of the value to be obtained from storage in EMMA relative to SPLASH, since the additional constraints will limit EMMA's ability to use storage to optimize electricity production across time periods. These limits reflect actual limits associated with operation of the MH system. To the extent that these limits govern the value that can be obtained from storage in practice, the fact that they have better representation in EMMA will tend to mean that EMMA will provide a more accurate, albeit lower, forecast of storage value.

Documentation for SPLASH specifically notes that with a monthly time step, it does not capture "the cycling of flows at a hydro plant over the hours of a week". Thus, in producing forecasts, SPLASH will capture very little of the value associated with using hydro storage to arbitrage pricing differences between daily on-peak and off-peak periods. EMMA may capture more of this value in its forecast because of its breakdown of the time step into multiple on-peak and off-peak periods. This modeling difference will tend to produce higher values for storage in EMMA than SPLASH. Since this effect is of a different direction than that resulting from the modeling of constraints, the net impact on forecast values (i.e., does SPLASH or EMMA produce a higher forecast with respect to the value of storage?) is unclear. EMMA will, however, produce a more accurate estimate of the value of storage.

3.7.10.1 Estimates of Error

The Consultant maintains that there is $14.2 million difference in the storage value produced by HERMES versus SPLASH and that this represents "an operational reduction" on its "P&L". The Consultant also identifies the $14.2 million as an "operational risk", and as a "real economic value reduction". Although the precise meaning of the Consultant's assertion is unclear, we have interpreted it to mean that MH income may be $14.2 million lower annually because of differences in modeling approaches between HERMES (i.e., EMMA) and SPLASH.

We have not been able to duplicate these Consultant's calculations and, further, do not know the basis upon which they were derived. Based on our review of the models and of MH's approach to operating its generation facilities, we do not believe that there are any operational losses that arise as a result of modeling differences between HERMES and SPLASH.

In summary, we note that neither HERMES nor SPLASH were designed to be financial trading models or to provide estimates of the market value of storage. Both HERMES and SPLASH are water management models designed to meet Manitoba Hydro's operational needs in serving its firm load.

3.7.11 Drought Risk

For MH, the Consultant calculates the value of volume risk over a one-year period of $293 million. By assuming time independence, the Consultant estimates a volume risk of $0.65 billion over a five-year holding period. *(Consultant's Report, December 2006, pg. 33).*

The assumption of time independence by the Consultant is flawed. It is clear that there is serial correlation in the water flow data. This has the effect of expanding the quantum of volume risk, since there is a greater risk that drought conditions will persist than will be calculated under an assumption of time independence.

In the Consultant's Report of January 2008, the Consultant states that the $2 billion drought risk number quoted by MH to the PUB has "an infinitesimally small likelihood" of occurrence equivalent to a one in 6.9 billion year probability. *(Consultant's Report, January 2008, pg.11.)* The one in 6.9 billion year figure appears to be calculated as (1/93)^5. Thus, it is the probability of an event that has one in 93 chance of occurring in one year, occurring 5 years in a row.

The calculation is appropriate if:

- Future water flows in any given year are obtained by drawing from among the 93 values observed in the past 93 years.
- Each year's flows are independent of the prior years' flows.
- We are only concerned with a scenario in which one of the observed low flow years is repeated five years in a row. (Thus, we are not concerned about the impact of other relatively low-flow years.)

The Consultant used this figure in its first report to argue that MH was over-estimating drought risks to the PUB.

In the Corporate Risk Management Report filed in the current rate application, MH quotes the financial impact of drought as $2.4 billion. This is calculated by assuming that water flows during the period April 1987 through March 1992 are repeated. It further states that drought costs would be higher if the larger 1936-1943 drought was used as the basis of the estimate.

The Consultant appears to be underestimating drought risk probability by a large margin. If MH's analysis is based on actual flow patterns observed in the recent past, this suggests that the probability of reoccurrence is much higher than one in 6.9 billion years.

The Consultants figure is appropriate for the repeat, five years in a row, of a given level of flows with a probability of one in 93 of occurring. However, this is not an appropriate measure of the risk associated with low water flows because:

- Water flows are serially correlated, and low flow years are likely to be followed by additional low flow years.
- Drought risks do not just arise from a single case of the lowest annual flow in the past 93 years happening 5 years in a row. The next lowest flow years are all relatively close together. Even if we accepted the Consultant's assumption of time independence, the probability of drought risks would depend on the various permutation and combinations of all of the relevant low flow years, and this

would be much higher than just the single case of the worst year happening 5 years in a row.

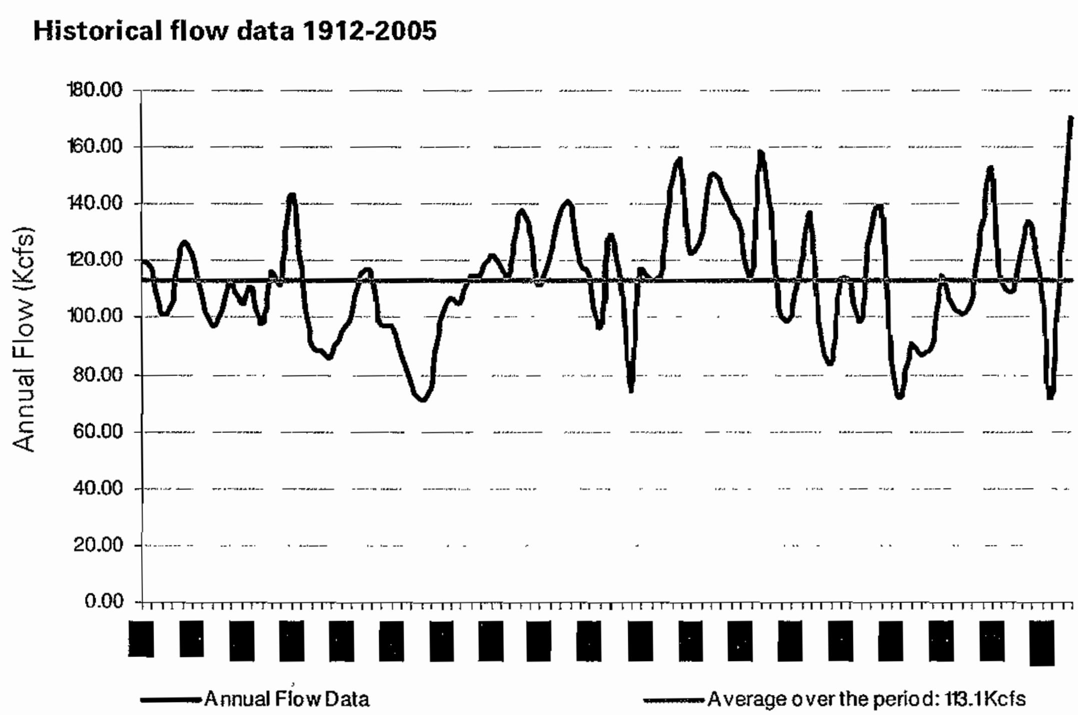
MH's use of actual flow sequences to measure drought risk is consistent with practices at other utilities and avoids the need to develop statistical models of underlying water flow processes.

3.7.11.1 Analysis of Flow Data

In this section, we analyze the statistical properties of MH flow data. This supports our finding that the Consultant did not account for key statistical features of MH's water flow record.

In order to assess drought risk, we analyzed the historical data to see whether low flow years happen independently of each other or in clusters. The data we used is the weighted average annual flow from 1912 to 2005. The initial graph of the data is displayed in Exhibit 3-16.

Exhibit 3-16: Historical Flow Data 1912-2005



Source: Manitoba Hydro

The mean over the period is 113.1 Kcfs and the standard deviation is 20.73 Kcfs.

From a visual analysis, we can infer that, indeed, low flow years and flood years tend to come in clusters. (For this purpose, we consider low flow years to be those years where the flows are below the average, and flood years the years where the flows are above the average.)

To confirm our visual impression, we performed serial correlation (or autocorrelation) tests on the data. Serial correlation is defined as the correlation of the variable with itself over successive time intervals. It is a statistical tool for finding time-series patterns. A positive serial correlation means above average values in one period tend to be associated with above average values in the following period. Similarly, below average values in one period will be associated with below average values in the following period.

Negative autocorrelations lead to the opposite conclusion (values that are above average in one period tend to be associated with below average values in the next). Like correlation values, autocorrelations are values between -1 and 1.

The order of an autocorrelation number is the time interval between the values for which the autocorrelation is computed (for example, autocorrelation of order 3 measure the correlation between a given year value and the value 3 years later)

We computed the autocorrelations of order 1 to 5 on the data. The results are given in Exhibit 3-17 below.

Exhibit 3-17: Autocorrelations of Water Flow Data

Order	Value
1	0.488
2	0.090
3	0.236
4	0.297
5	0.132

Source: KPMG calculations from Manitoba Hydro data

We observe that the autocorrelation values are positive (which means that high or low values tend to come in clusters). We are mainly interested in the autocorrelation of order 1 and we want to test if it is statistically different from zero.

There are several methods to perform that test. We chose the method where we establish a regression relation between the standardized values of flow in a given year against the standardized value of the previous year (standardized values are calculated by subtracting the mean from the data point and dividing the result by the standard deviation). The slope of that regression relation is an alternative estimate of the autocorrelation number. We can estimate the regression parameters and build a confidence interval around the slope parameter to check if it is significantly different from zero.

We conducted the analysis for the auto correlation of order 1 and the regression results are outlined in Exhibit 3-18.

Exhibit 3-18: Autocorrelations of Order 1

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*
Intercept	0.0125	0.0902	0.1383	0.8903	-0.1666	0.1916
X Variable 1	0.5326	0.0941	5.6576	0.0000	**0.3456**	**0.7196**

Source: KPMG calculations from Manitoba Hydro data

The 95% confidence interval (0.3456 to 0.7196) around the autocorrelation estimate, which is the coefficient for the X-variable, shows that the estimate is significantly different from zero.

The autocorrelation coefficient derived from the regression analysis is slightly higher than that determined from the first methodology because the regression approach uses one less data point (2005). The difference is noticeable in this case because 2005 is a year of very high flow.

3.7.11.2 Average Drought Length

Using the same data set, we also computed the average length of a drought period. As an initial step, we defined a drought period as consecutive years where the annual flow is below the average over the entire period (113.1 Kcfs). Exhibit 3-19 displays these results as well as the average length at the end of the table.

Exhibit 3-19: Drought Periods with Below Average Annual Flows

Drought #	Start year	End year	# years
1	1914	1916	2
2	1918	1925	7
3	1926	1927	1
4	1929	1934	5
5	1936	1945	9
6	1952	1953	1
7	1958	1959	1
8	1960	1962	2
9	1976	1978	2
10	1980	1983	3
11	1984	1985	1
12	1987	1992	5
13	1993	1996	3
14	1999	2000	1
15	2002	2004	2
TOTAL			**45**
AVERAGE			**3**

Source: derived from Manitoba Hydro

If we define drought period as periods with at least two consecutive years below average, we have the results as shown in Exhibit 3-20.

Exhibit 3-20: Drought Periods Defined as Below Average Flows for Two Consecutive Years

Drought #	Start year	End year	# years
1	1914	1916	2
2	1918	1925	7
3	1929	1934	5
4	1936	1945	9
5	1960	1962	2
6	1976	1978	2
7	1980	1983	3
8	1987	1992	5
9	1993	1996	3
10	2002	2004	2
TOTAL			**40**
AVERAGE			**4**

Source: derived from Manitoba Hydro

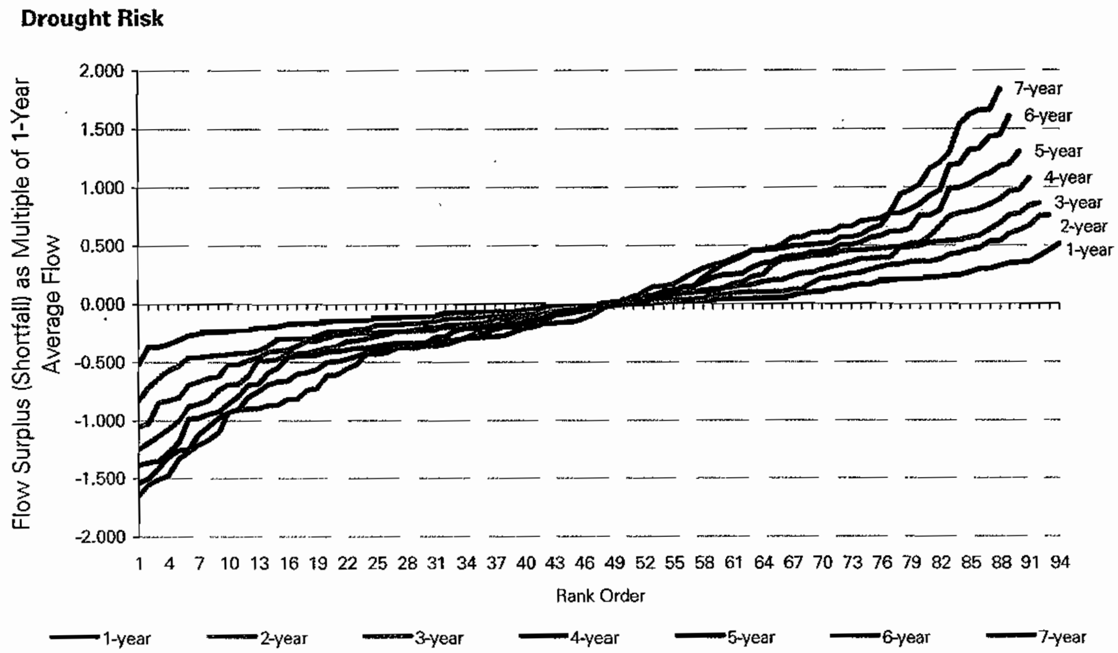
Therefore depending on how we define a drought period, it lasts on average three to four years.

In conclusion, the flow data does not seem to be serially independent and low flow years tend to be followed by low flow years and similarly, high flow years tend to be followed by high flow years. In addition, drought periods tend to last on average three to four years depending on the definition used for a drought periods. This information may be useful when assessing drought risk.

3.7.11.3 Drought Severity

Drought severity can be analyzed by looking at the total shortfall in water flows, relative to average flows, for different time periods. Exhibit 3-21 analyzes periods of from 1 to 7 years in length within the 94 year water flow record. It ranks periods of equal length in terms of the total shortfall in water flows. Shortfalls over the period are measured in terms of the volume of water in one year of average flow.

Exhibit 3-21: Flow Surplus (Shortfall) for Different Time Periods



Source: derived from Manitoba Hydro data

Exhibit 3-21 provides an indication of how drought risk, meaning the cumulative energy shortfall for a drought period, has varied for different time periods over the historical record. As shown in the Exhibit, the worst single year on record has flow that is just below one-half of the average or mean annual flow over the historical record. The worst 7-year period has a total shortfall in flow that is equal to 1.65 times the flow in an average year, or about 3 times the shortfall in just a 1 year period. Periods from 4 to 7 years in length are relatively close together in terms of the shortfall associated with the worst period on record. Thus, the increase in drought risk for longer holding periods levels off after four years or so.

3.8 Sensitivity Analysis – Impact of Price Inputs on HERMES

KPMG asked Manitoba Hydro to examine the impact that different price forecasts can have on MH production decisions. MH did this through a series of special runs within HERMES.

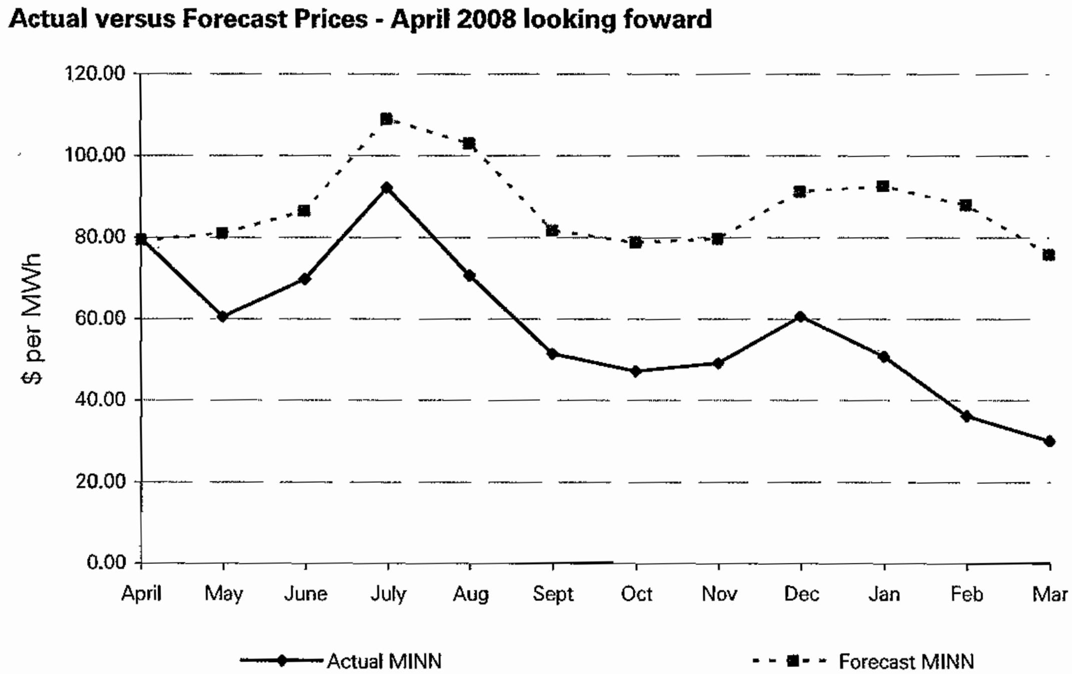
The runs were designed to keep factors other than price constant across various scenarios. Accordingly, differences between the runs were only due to differences in price forecasts and were not the result of other factors. The runs were "artificial", in that they involved a number of unrealistic and arbitrary assumptions, but they can reasonably be considered to provide an upper bound on the losses that MH could incur from having poor price forecasts or from being negligent in incorporating up-to-date market data. The runs undertaken are more fully described below.

3.8.1 Initial Run Set and Optimal Run

3.8.1.1 Common Elements

The runs were undertaken for the system looking forward from April 2008. This is a point at which purchased price forecasts for the following 12 months were relatively optimistic, relative to the actual prices that were ultimately observed. Not unexpectedly, the divergence between forecast and actual MISO prices was greater for points further into the future. This is illustrated in Exhibit 3-22.

Exhibit 3-22: Actual versus Forecast Prices – April 2008 Forward



Source: derived from Manitoba Hydro data

The model was run so that ending lake levels were common across the runs. For the initial set of runs, ending lake levels at Lake Winnipeg were set to 713.1 feet. In normal HERMES runs, ending lake levels are determined by an optimization process that takes into account prices during the year and ending values for the water in storage. For these runs, this optimization process was over-ridden. Unless it was over-ridden, differences in prices through the year across the runs could result in different ending lake levels, given common assumptions for the value of water in storage at the end of the year.[5] If we allowed lake levels to differ for the runs, then financial comparisons would be affected because different runs would have different total volumes of energy production within the year, rather than just differences in when this production was scheduled.

MH loads were the same across all runs. This means that differences in production schedules translate into differences in import and export transactions. Changes in thermal production schedules are minor, because thermal is generally a high cost source relative to potential spot market purchases. Thus thermal plants usually only operate when there are constraints on import capacity.

[5] *A run with higher prices in the optimization period than another run will generally have lower ending lake levels, because the model sees relatively greater value from selling energy in the optimization period relative to saving it as ending "inventory".*

3.8.1.2 Run with Perfect Foresight (Optimal Run)

For each comparison or run set, the first run is one in which HERMES has perfect foresight with respect to both water flows and future prices. We call this the Optimal Run. Thus, the inputs to the EMMA model were the prices that were ultimately observed at MISO, and median water flows. (Water flows were based on the median level from historical records.)

The Optimal Run provided us with an estimate of operating results for MH, under a median flow scenario, in the case in which MH had perfect knowledge with respect to MISO prices, and hence potential export revenues (and import costs) in each time period. By operating results, we mean net export revenues less generation costs.

3.8.2 Run Based on External Forecast (Forecast Run)

For each comparison, in the second run, HERMES was given external forecast prices as an input to its optimization process. We will call this the Forecast Run. As noted above, the external forecasts substantially overestimated the price levels that were ultimately observed.

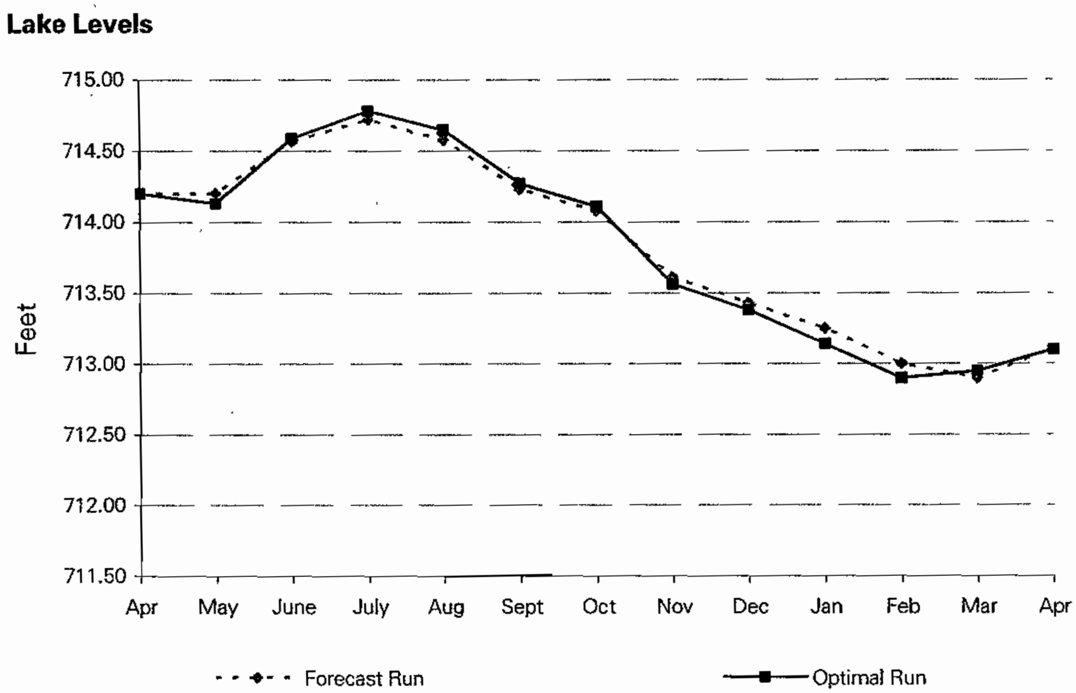
As in the Optimal Run, the inputs to this model included median water flows. As a first step in the Forecast Run, EMMA was used to create an operating plan for MH based on forecast prices. By operating plan, we mean a schedule for the operation of MH generating plants, and for interruptible purchases and sales, to meet firm MH loads. Firm MH loads under the Optimal and Forecast Runs were identical, and included both domestic load and net commitments under long-term firm contracts.

To obtain operating results for the Forecast Run, the operating plan obtained immediately above was "locked in" for the full 12-month projection period. This plan was then applied to the market environment in which actual MISO prices were realized. This run thus provided us with an estimate of operating results for MH, under a median flow scenario, in the case in which MH had optimized production schedules based on PIRA forecasts, and then rigidly applied this schedule under actual market outcomes.

As expected, operating results for MH under this scenario, in terms of net export revenues less operating costs, were less favourable than under the Optimal Run. For our first set of runs, the Forecast Run had operating results that were $25.3 million less favourable than the Optimal Run.

Exhibit 3-23 shows monthly levels at Lake Winnipeg for the two runs. The two runs show very similar levels, which shows that the optimization process is affected to only a limited degree by price levels. The drop in lake levels in the latter part of the year relative to the summer is driven by the need to meet MH domestic loads, which are temperature related.

Exhibit 3-23: Lake Level Comparison

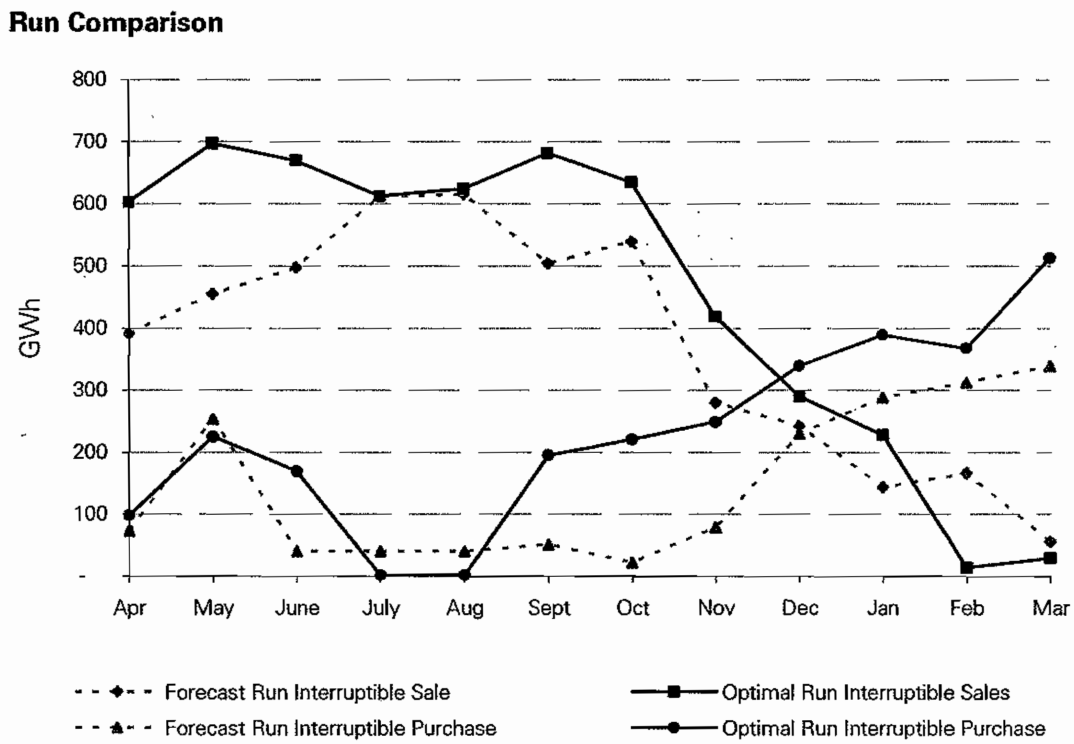


Source: sensitivity analysis runs applied to Manitoba Hydro data

The dotted line, which represents the operating regime under the Forecast Run, shows higher levels at later points in the year. The model keeps higher levels in order to minimize market purchases later in the year. This reflects the fact that it expects these prices to be higher than the Optimal Run.

Differences in operation are shown in Exhibit 3-24. The Forecast Run reduces sales in the spring and in the fall in order to reduce the reliance on purchases later in the year to meet winter loads (when it expects prices to be high).

Exhibit 3-24: Expected Imports and Exports



Source: sensitivity analysis runs applied to Manitoba Hydro data

3.8.3 Alternative Run Set

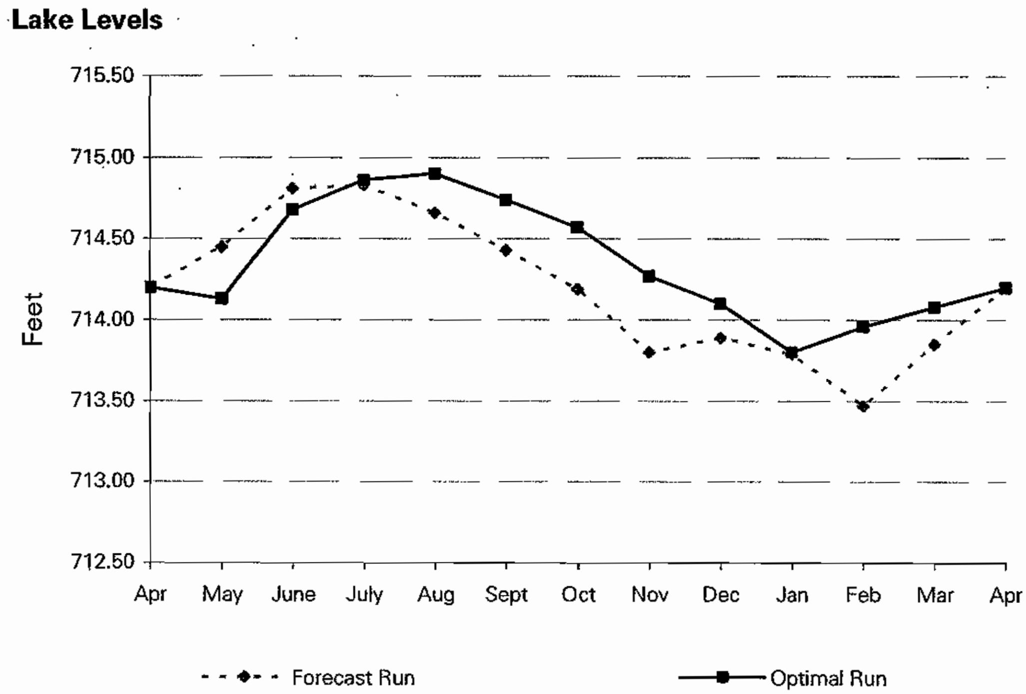
In the initial set of runs outlined above, lake levels declined over the course of the year. The initial lake level was 714.2 feet, reflecting relatively high actual water levels in spring 2008. The ending lake level (which was forced) was set to 713.1 feet, which reflects a level that is closer to the historical average ending levels.

Under the Alternative Run Set described below, MH tested a scenario in which lake levels were maintained at the same high level relative to the historic average. This allowed us to examine the impact that alternative ending lake levels could have on the results.

Under a scenario where high water levels are maintained, less energy is available from hydroelectric generation in the course of the year. Under this set of runs, differences between the Optimal and Forecast Runs were found to be greater. This reflects the fact that the system has more surplus export capacity than scenarios with higher production. This means, in turn, that the system can shift more production from one time period to another within the year when it tries to optimize against a particular price forecast. Because the system is selling less energy into export markets and is trying to focus on the highest price periods, there is more impact from moving this energy from one period to another.

Lake levels under the alternative run set are shown in Exhibit 3-25 below. As expected, ending lake levels are the same as starting lake levels for both the Optimal and Forecast Runs.

Exhibit 3-25: Lake Levels Comparison – Maintain Lake Levels



Source: sensitivity analysis runs applied to Manitoba Hydro data

Under the Alternative Run set, differences between Optimal and Forecast Runs were higher than for our Initial Run Set, resulting in about a $45 million difference in net revenues. This compares to a difference of $25.3 million from the Initial Run Set described previously.

MH also tested a scenario in which lake levels were set to decline to 712.0 feet. Under this scenario, in which additional generation is available, the difference between the Optimal and Forecast Runs was much smaller, at only $5.6 million in net revenues.

3.8.4 Findings

As outlined above, the hypothetical scenarios outlined above suggest that price inputs, if incorrect or "stale", could influence operating results by as much as $45 million.

There are a number of reasons to believe that the value of $45 million significantly overestimates the potential losses, or foregone revenues, that MH would experience in the event that prices were inaccurately entered into the HERMES system. These reasons are:

- The runs assume that production schedules must be locked in one year in advance. In practice, HERMES is run weekly, so that the model is updated on a rolling basis. Price information can be updated with each weekly run, meaning that divergence in price information should be less than that assumed in the test. As a result, the divergence in production schedules should also be less.

- The run was done for a period in which the divergence between the two potential forecasts (the external forecast and a "perfect" forecast) was relatively large.

- The Optimal Run, which was our benchmark for comparison, assumed perfect foresight of actual prices. In practice, this degree of forecasting accuracy cannot be achieved. A more realistic comparison would be between a schedule developed for one forecast and a schedule developed for a "better", rather than a perfect forecast.

- The runs assume perfect foresight with respect to both loads and water flows. Under actual operating conditions, uncertainty with respect to these other parameters may further reduce the value that can be obtained from better information on price.

In summary, these runs suggest that inefficiencies in operating schedules that could result from stale or inaccurate price inputs are likely to have only a limited impact on financial results achieved. Variations in water flow are likely to have a much larger influence on optimal operating schedules (and on MH's financial returns). Constraints on import and export transactions, and the need to meet domestic winter loads, also have significant influence on production schedules.

3.9 Review of HERMES – Conclusions and Recommendations

In this Section, we present a summary of our conclusions and recommendations related to HERMES based on the analysis in the previous sections.

3.9.1 Conclusion

As described earlier, HERMES is a complex set of data and tools. It was developed some 30 years ago but has been evolving over time. By necessity, HERMES is a large and complex model. It has to model a large and complex system with a high degree of detail.

The following are our conclusions with respect to HERMES.

- The overall model logic appears to be appropriate. It relies on linear programming, which is an accepted methodology for utility operations planning.
- The model captures all of the key factors that influence optimal production schedules.
- A high degree of technical expertise and specialization is required to operate the models.
- Model operators appear knowledgeable.
- Formal model documentation appears to be very limited. For example, there is no user's manual.
- Operation of the model is very reliant on the knowledge of a few highly specialized individuals.
- While the basic structure of the model is not changed, the forecasting equations are continuously fine-tuned. This continuous fine-tuning of the forecasting equations relies on the judgment of the model operators.
- There appears to be limited formal or documented validation of individual components of the model. At the overall level, however, HERMES appears to produce estimates of production that are close to actuals.

- The skills required to operate HERMES are derived on-the-job training and experience. The nature of this process is that it has not been highly reliant on formal documentation or training courses. While this is understandable in the circumstances, it creates some risks with respect to knowledge sharing and corporate exposure to the potential loss of key personnel.

- Lack of formal documentation, oversight or validation also creates a risk that the overall model is seen as a "black box" to outside stakeholders, both within and outside the company.

- MH would benefit from more formal documentation and oversight of the modeling process. However, MH must also be aware that such documentation and oversight will require additional resources without necessarily producing an immediate financial return in terms of improved forecasting performance.

3.9.2 Recommendations

As indicated previously, it is beyond the scope of our review to determine whether HERMES is the best model for MH. Nonetheless, we have identified a number of areas which may be worthy of further investigation by MH management.

3.9.2.1 Flow Forecasting

As noted in our discussion on antecedent forecasting in 3.6.2, other utilities and government agencies are exploring the use of full hydrologic models that predict water flows based on input data on actual or forecast precipitation over a watershed. Advancements in remote sensing technology may increase the feasibility of this approach, even for MH's large watershed. MH should continue to monitor developments in the field to take advantage of new methodologies that become available.

Given the uncertainty of impacts from climate change, MH may also wish to formally examine the potential impact of changes in water flows from the historical pattern. Thus, it should undertake scenario analyses to assess the financial impact of droughts worse than the historical record.

This type of scenario analysis can be used for the purpose of risk analysis, and does not necessarily need to be used as the basis of financial forecasts or for the determination of dependable energy. MH's current approach to forecasting and to calculating dependable energy appears reasonable and consistent with practices at other utilities. Additional scenario analyses, however, will provide information to stakeholders regarding the financial implications of potential developments that are outside of the historical record.

MH has undertaken an analysis of the impact on financial results if there is a gradual change in average streamflows over a 35-year period. This analysis, which was undertaken in 2004, assumed that there would be either a 20% increase or a 20% decrease in expected streamflows by the 2039 end date. Streamflow changes were assumed to take effect gradually over the intervening period. Under the low-flow scenario, annual domestic rate increases were 0.7 percentage points higher than under a scenario with no water flow change. *(MH Briefing Note: Economic and Financial Impacts of Changes to Manitoba Hydro's Water Supply from Climate Change, 2004 08 24)*

We understand that MH is engaged in rainfall run-off modeling for the entire Churchill Nelson basin as part of climate change studies. These calibrated models have the potential to assist MH in the area of short-term water supply forecasting.

MH reviewed a number of climate change models as part of its examination of the environment impacts of the Wuskwatim Generating Station. Its review noted that 18 out of 20 global climate change models forecast an increase in precipitation in the Wuskwatim region as a result of climate change. This review also cautioned, however, that increases in precipitation would not necessarily translate into increases in runoff and water flows. Impacts are uncertain because increased precipation could be offset by changes in evaporation, evapotranspiration, land cover, and wind. Furthermore, there is uncertainty about the intensity, duration and seasonal variability of precipitation. *(Evidence Presented at Clean Environment Commission Hearings on Environmental Impacts of Wuskwatim Generating Station.)*

3.9.2.2 Model Review

While comprehensive independence may not be practicable, the policy should explicitly provide for an effective communication process between modelers and decision markers. Technical complexity should not liberate model builders from the responsibility for providing clear and informative descriptions of modeling assumptions and limitations to senior management.

3.10 Review of SPLASH

This section provides a review of the SPLASH model, its conceptual and empirical validity, optimization approach and operations.

3.10.1 Model Overview

SPLASH (Simulation Program for Long Term Analysis of System Hydraulics) was developed by the Resource Planning and Market Analysis Department between 1990 and 1996. The purpose was to provide a computational tool that can be used to study the economics and adequacy of various expansion scenarios and to evaluate the options and opportunities available in the electric power market. More specifically, SPLASH is to be used in generation expansion studies.

SPLASH was designed as an energy balancing model to simulate the long-term operation of the hydroelectric energy supply system over a wide range of potential stream flow conditions for a specific load growth and system expansion scenario.

The output from SPLASH provides information to evaluate the economics of power resource options such as power export marketing contracts, system enhancements, and integration of non-hydraulic resource options such as wind energy and gas-fired combustion turbines.

There is no direct reconciliation between results from SPLASH and HERMES. The reason cited by MH personnel was that the data inputs and disaggregation are different and so the results are not easily comparable. However, both SPLASH and HERMES are calibrated to actuals by averaging over the modeling timesteps.

3.10.2 SPLASH Model Validity

3.10.2.1 Conceptual Validity

As noted earlier in the discussion on the modeling of the value of storage, SPLASH assumes perfect foresight with respect to future water flows. This means that the model provides a more optimistic view of operating results than will actually be achieved in times of drought.

The operators of SPLASH maintain that this aspect of the model has limited impact on the usefulness of SPLASH in its major role – to examine the relative value of different development sequences. (A development sequence is a particular scenario for the build-out of new generating capacity. Development sequences are generally designed to accommodate a particular forecast of load growth.) The assertion that perfect foresight is not important to economic evaluation reflects the fact that the assumption of perfect foresight should have a similar impact on different development sequences, and therefore should not affect the relative ranking of these sequences. While this assertion seems plausible, it would be desirable to have a more formal demonstration that perfect foresight does not limit SPLASH's usefulness as a ranking tool.

KPMG has a concern that the assumption of perfect foresight will tend to understate operating costs when the model is used to generate forecasts of future financial results. MH management maintains that they offset this bias in the model calibration process, but it would be useful to have separate quantification of the impact of the perfect foresight assumption. (Model calibration is required with respect to a number of inputs. For example, market pricing curves translate assumptions about expected average price levels to estimates of the price received in individual time periods and for individual transactions. The calibration of these types of inputs can be done in such a way as to offset the optimism bias.)

3.10.2.2 Drought Estimates

In addition to being used to prepare financial forecasts, SPLASH is used to estimate the financial impacts to MH of drought. As discussed in the section on drought risk, SPLASH outputs tend to underestimate the financial impacts of drought during the period of the drought. This reflects the fact that the model assumes that reservoirs will brought to minimum levels of storage during the course of a drought, since the model "knows" when the drought will end. In actual practice, management at MH will operate the system more conservatively, and will maintain reservoir levels above the levels predicted by SPLASH in order to address the fact that the drought may last longer than the historical record assumed within SPLASH. This will lead to higher operating costs in the period of the drought as a result of additional imports and fossil fuel purchases.

The issue of ending reservoir balances raises a conceptual issue with respect to the measurement of drought risk. With an assumption of declining reservoirs to the end of a drought, some of the losses associated with a drought will implicitly be carried forward into future periods. Future periods will have less hydroelectric energy than they would otherwise because they will need to build reservoir levels back up to their "normal" levels. This will lead to some combination of reduced exports, increased imports and/or increased fossil generation in these future periods. The associated costs will not be included in the financial impacts (in terms of a reduction in net income) that are reported for the drought period alone.

Management's tendency to operate the system more conservatively than SPLASH assumes simply works to bring back some of these future costs into the period of the drought. The period following the drought will have more water in storage than assumed by SPLASH, reducing future costs for imports and thermal generation. (For the moment, we are assuming that prices are constant across time; costs may differ across time periods in the event that market prices vary over time and affect the costs of imports and exports. MH maintains that overall MISO prices are not affected by drought in Manitoba, since MISO is largely a fossil-based system. Prices at the MHEB node, however, may be affected by the shift from sales to purchase in the event of a drought.)

As a partial offset to the factors noted above that result in an understatement of drought costs, SPLASH will overestimate certain costs because it ignores the potential to import power on a non-firm basis. SPLASH only assumes that imports occur under MH's Diversity Contracts, which are considered firm. The ability to schedule opportunity purchases through the spot market and from short-term contracts is ignored. To meet drought conditions, SPLASH will generally therefore assume that more use is made of MH's relatively inefficient thermal generating plants. In practice, less costly power is generally available from MISO and this tends to reduce the costs of the generation needed to cover the shortfall in energy from hydroelectric sources.

There is an additional complication that should be acknowledged in our discussion of this issue. This is the fact that management's tendency to maintain higher water levels will result in somewhat greater risk of the "spill" of water in subsequent periods. The risk of spill is greatest if the drought is followed by a period of very high precipitation. The "spill" of water is a true economic cost, since the value of energy production from the associated water is foregone. The risks of higher costs from spill may be well worth taking, given the potential for very high costs in the event that the utility is short of power as a result of maintaining low reservoir levels. Stakeholders would also benefit from explicit quantification or discussion of this issue.

The impacts of these various factors do not appear to be well documented or communicated. MH should explicitly quantify the extent to which SPLASH may underestimate operating losses in the period of the drought as part of its presentation of drought costs. This would facilitate greater understanding of the economic implications of the drought and of the modeling approach.

3.10.2.3 Optimization Approach

There are some differences between SPLASH and HERMES in their approach to modeling and optimization. For example, SPLASH assumes an optimal lake ending position of 713.2 ft for Lake Winnipeg. The Consultant refers to this as a "risk neutral" position. Our understanding is that this level was determined through some scenario analyses done previously, in which different lake levels were tested and an optimal level found that balances the risks of spill (which increase with higher lake levels) and the costs of additional imports and fossil fuel purchases (which increase with lower lake levels). The optimization process assumes very little economic value for water levels higher than the target ending position. Below the target level the model maximizes the use of thermal sources and imports in order to support moving to the target level. In its economic run, SPLASH optimizes within each 12 month window.

HERMES, in contrast, does not have an assumed optimal lake ending level. Rather, it determines an optimal ending lake level in the course of any run based on the expected market prices during the optimization period and a function for the value for water in storage at the end of the period. The value of water in storage at the end of the period is a function of ending storage levels. This storage value function is generated within HERMES based on an analysis of the expected value of water in storage across 33 water flow scenarios (based on the last 33 years of actual water flow data), and looking forward for a 2-year period.

In summary, the HERMES optimization approach appears to provide for more explicit consideration in the production scheduling decision of the economic value, relative to current sales, of greater or lesser ending storage levels. This seems appropriate given that HERMES is the tool that has the greatest impact on actual operations in the near term. Decisions in the near term, as supported by HERMES, can respond to prices that are currently observed in the market. (Although, as noted earlier, prices have a relatively limited impact on production decisions relative to other factors such as water flows.) As a longer-term tool, SPLASH has less need to adjust decisions based on current market data. Rather, it simply needs to capture the "average" or expected economics of a particular decision or sequence.

Our understanding is that MH does not usually commit all of the system's dependable energy to serving Manitoba load or long-term contracts. MH tries to maintain some surplus dependable energy to deal with uncertainty in the rate of domestic load growth or in other factors.

3.10.2.4 *Empirical Validity*

Since SPLASH was implemented in 1996, MH indicated that results from numerous studies have been reviewed to confirm that model outputs are representative of system characteristics. In particular, price and volume relationships used to model market transaction are periodically calibrated to ensure that they match actual outcomes.

A limited peer review was commissioned by Manitoba Water Stewardship in 2005 in connection with the consultation process related to the Wuskwatim hydroelectric project. In that peer review, three separate consultants were asked to provide their opinions on the adequacy of the SPLASH model. The peer review concluded that the SPLASH model is sufficiently accurate to represent the change of the water regime caused by the addition of the Wuskwatim power plant to the Manitoba Hydro system. The scope of this review was relatively limited. Hence, MH would benefit from a more comprehensive review to ensure that the model is appropriate for evaluating the economics of larger additions such as Keeyask and Conawapa, and associated contracts for the long-term sale of firm power.

3.10.3 SPLASH Model Operations

Personnel in the Resource Planning and Market Analysis Department perform quality control checks on the SPLASH output data with respect to other resource planning studies and to available actual operational data.

As noted previously, there is currently no specific corporate policy statement on the development and use of modeling tools and risk management. These tools are managed through the application of existing approval and risk management policies and procedures.

SPLASH is designed for carrying out "individual" resource planning studies. Data inputs from the annual Power Resource Plan (PRP), such as Manitoba load forecast, fuel prices and market energy prices, are input into SPLASH in April/May to serve as the baseline for studies through the rest of the planning year. As noted elsewhere, SPLASH takes a significant amount of time to complete a run.

The use of SPLASH requires an understanding of MH's overall system operations and interactions with interconnected utilities and markets.

As with HERMES, a small group of experts are responsible for the operation of the model.

3.11 Review of PRISM

3.11.1 Model Overview

As noted in Section 3.4 of this Chapter, PRISM is a simplified tool designed to be used by the Export Marketing Department for tactical use to analyze the financial impact of variations in a number of factors which affect Manitoba Hydro's operations, including water conditions, expected load, gas and electricity prices, export sales and forward contracting risk, transmission access and wind energy. It is an energy balancing model designed to measure MH's risks under lower than average flow conditions.

PRISM is implemented using @Risk, which is a risk analysis and simulation add-in for Microsoft Excel.

3.11.2 Assumptions and Data

PRISM is a highly simplified representation of the MH system. It has a number of key limitations:

- The model breaks the year up into only four discrete time periods: the summer and winter season, and within each, peak and off-peak. This means that the system has limited to no representation of demand and capacity issues.
- The model operates over only a five-year horizon. Thus, it can provide analysis of yearly impacts over the short term, but cannot evaluate long-run economics.
- The model uses assumed distributions for input prices, rather than using actual price patterns derived from analysis of past market activity.

We have one suggestion for improvement of this model. Electricity and natural gas prices are modeled with a normal distribution. There is good evidence, however, that energy prices are not normally distributed, with prices showing more extreme values than would be obtained from a normal distribution *(Dragana Pilipovic, "Energy Risk – Valuing and Managing Energy Deriatives", McGraw-Hill, 1998, p.26)*. MH may wish to explore alternative distributions as inputs to the PRISM model.

PRISM is used as a screening tool, and must be evaluated in this context. Its limitations appear acceptable if it is used simply as a screening tool, and more detailed analyses are done prior to implementation of any strategy that may be under review.

3.12 Review of the Issue of Multiple Models

Some concerns have been raised that MH has multiple models. Concerns associated with multiple models include the following:

- It becomes more difficult to ensure that models use common assumptions and logic.
- Additional effort is required for oversight and monitoring of model operations.
- There may be unnecessary duplication of effort.

Despite these concerns, there are a number of factors that drive utilities to have a variety of models. The key factor is that models are used for different purposes. Each of these purposes has different requirements with respect to time horizon, level of detail, accuracy, the nature of scenarios to be analyzed, interface with other systems, and accessibility to potential user groups. Separate models may also develop simply as a result of how needs were addressed in the past.

Our research into practices at other utilities established that it is common for utilities to use a relatively small portfolio of models. For example, a number of utilities use a different model for short-term power utilization and long-term resource planning. Some utilities also run external price forecasting models that get integrated as components of their internal models.

MH takes reasonable care to ensure that models are used in a consistent manner across the corporation and incorporate common assumptions or methodologies. For example:

- The HERMES model develops detailed load forecasts (which are disaggregated into weekly time segments) which are consistent with MH's annual corporate load forecast.
- Each of the operating models are updated to ensure that they include required information with respect to MH import and export contracts.
- The models use the actual historical record for water flows at MH in generating hydrologic scenarios.

3.13 Conclusion

With respect to the modeling approach at Manitoba Hydro, based on our analysis, we find:

- MH has developed a suite of models that capture the key characteristics of the MH system. These models are used to help optimize system operations and to support long-term capacity planning.
- We are satisfied that MH has taken appropriate care and due diligence in developing and maintaining these models and in using them in its operations planning process.
- MH's current approach to forecasting and to calculating dependable energy appears reasonable and is consistent with practices at other North American hydroelectric utilities. It is reasonable to rely on historical flow data for estimating dependable energy.

KPMG

4

4. Power Sales Management

This chapter examines key issues associated with Manitoba Hydro's practice of entering into long-term fixed price contracts for export power sales.

This chapter is organized under the following headings:

- 4.1 Scope of our Review
- 4.2 Key Findings
- 4.3 Approach and Methodology
- 4.4 Rationale for Exporting Power
- 4.5 Rationale for Long-Term Contracts
- 4.6 Long-term Contract Pricing
- 4.7 Sales Volumes Commitments
- 4.8 Contract Structure
- 4.9 Manitoba Hydro's Risk Mitigation Strategies for Power Sales
- 4.10 Drought Risk Analysis of MH's Preferred Development Sequence
- 4.11 Quantification of Drought Risk and Associated Risk Capital Reserves
- 4.12 Conclusion.

4.1 Scope of Our Review

In Phase 1 of the Review as shown on Exhibit 1-1, KPMG identified three Issues within the Theme of Power Sales Management. The three Issues and along with a summary of the Consultant assertions of each Issue are outline below.

- Issue 1 – Pricing methodology for firm power sales

The Consultant asserts that MH is using incorrect pricing methodologies for the sales price in long-term energy contracts. Specifically, the Consultant asserts that MH is not properly making use of current market price information and is not properly identifying and quantifying all the risks (e.g., liquidated damages, volumetric risk, etc.) associated with such long-term supply contracts. As a result, the Consultant asserts that MH is not building in an appropriate premium in pricing these contracts.

The Consultant acknowledges the reasons cited by MH as to why it was willing to sell power for less than its apparent market value in these long-term contracts (i.e., because of the creation of transmission capacity and access), but rejects these as being valid reasons for such pricing. In this context, the Consultant recommends an overhaul of the pricing methodology used in the long-term fixed price contracts for energy sales.

- Issue 2 – Risk capital reserves

As described in the Issue above, the Consultant asserts that MH is using incorrect pricing methodologies for the sales price in long-term contracts and in particular is not properly identifying and quantifying all of the risks associated with having entered into long-term supply contracts. In that context, the Consultant asserts that MH is also not reserving a sufficient amount of risk capital for the export sales business, in light of its drought risk. The Consultant recommends the immediate cessation of export power market sales under long-term contracts until MH has an appropriate amount of risk capital reserved for this business.

- Issue 3 – Long-term contracts structure

The Consultant asserts that MH has suboptimized these arrangements due to the use of certain terms in the long-term contracts. The Consultant recommends: significantly shortening the duration of these contracts; sharing of risk in the market prices and premiums being charged including index or floating price provisions; and increasing optionality to MH's benefit.

In addressing these three Issues, we assess the following:

- MH's rationale for entering into long-term fixed price contracts;
- Its pricing of the power sold under such contracts;
- The sales volume commitments in such contracts in the context that over-committing its firm dependable energy production through these contracts could unnecessarily expose MH to volume risk;

- MH's structuring of contractual terms to mitigate the risks associated with long-term fixed price sales; and

- Its quantification of drought risk and its risk capital reserves in the form of equity reserved against such risk.

4.2 Key Findings

This section outlines our key findings with respect to power sales management.

With respect to the MH's methodology for firm power sales, we find the following:

- Prices in long-term contracts are a matter of negotiation between the parties, and must be acceptable to both parties for a deal to be done.

- In the course of negotiating these contracts, MH develops reference prices based on the two methodologies described above. Developing these two price estimates provides MH with an indication of the potential range of a contract's price. Based on this information and leveraging the considerable industry experience of the key MH personnel involved with the negotiations, a mutually agreeable price is set in the term sheets for new long-term contracts.

- Based on our analysis of this pricing process, MH has an appropriate methodology for arriving at the sales price in its long-term contracts. As mentioned previously, the pricing methodology explicitly incorporates relevant market pricing forecasts and, further, includes a premium. And as detailed in this chapter, long-term contracts mitigate MH's market risk through diversification of its export sales mix, and mitigate its drought risk because of both the returns generated by the contracts and the creation of the transmission capacity.

- Related aspects of this Issue are addressed in the Issue related to treatment of risk in Power Risk Management (Chapter 6).

With respect to risk capital reserves, we find the following:

- As stated in our findings related to Forecasting Models (Chapter 3) and the Issue above related to pricing methodology for firm power sales, we are satisfied with the methodology used by MH in arriving at the sales prices in its long-term contracts and in the treatment of lake water level balances in the quantification of drought risk.

- Further to the analysis described in Chapter 3, KPMG asked for additional stress tests of MH's preferred expansion plans (which include new long-term contracts) incorporating various drought scenarios and market price scenarios. KPMG also asked for corresponding stress tests to be conducted for an alternative expansion plan that did not include new long-term contracts. The results of these stress tests indicate that MH's ability to withstand the financial impacts of a drought is improved under the expansion plan that includes new long-term contracts.

- To summarize, on the basis of the policy decisions in place with respect to risk tolerance, MH quantifies its drought risk appropriately and currently provides for appropriate levels of reserves of risk capital against its projected drought risk.

With regard to long-term contracts structure, we find the following:

- As with prices, contractual terms in long-term agreements are a matter of negotiation between the parties, and must be acceptable to both parties for a deal to be done.

- The provisions identified by the Consultant, as well as other comparable novel terms, change the nature of the commercial arrangement for MH and the counterparty by either making the contract riskier for the counterparty or changing the nature of the product. Without knowing how the counterparties would value such changes, it is speculative to determine whether such provisions would help or hurt. MH's costs would increase, potentially significantly, if it were to commit to multi-billion dollar capital investments with contractual sale commitments of shorter durations (e.g., two years), potentially rendering the projects infeasible.

- Optimal risk sharing in a contractual arrangement dictates that risk should be allocated to the party that is best able to manage that risk. In this context, as addressed in Chapter 4, many of the potential novel terms that could be considered in a long-term firm sales contract between MH and a counterparty involve shifting a particular risk to the counterparty. In many cases, however, MH would generally be in a better position to assess and/or manage the risk than the counterparty, and would therefore generally be better off in the long run if it retained the risk (e.g., by being compensated for retaining the risk or avoiding the costs associated with transferring the risk).

- Overall, we found no basis to conclude that MH had suboptimized its contractual provisions.

4.3 Approach and Methodology

To assess these issues, we have used the following approach and methodology:

- interviewing senior MH management with direct knowledge of and input into MH's decision to enter into long-term contracts;
- examining relevant MH policies and documents related to various aspects of long-term contracting (e.g., pricing, approvals);
- reviewing MH's long-term contracts and term sheets;
- industry research;
- consulting with one of the specialist sub-consultants that KPMG engaged (NERA) to augment our analysis of MH long-term contracting; and
- conducting scenario analysis from special runs of MH models.

Note that our analysis and observations on MH's long-term export power sales contracting strategy is partially based on the use of MH's modeling tools, especially for hydrological modeling and dependable energy estimation. Chapter 3 examines the various aspects of MH's modeling tools.

4.4 MH's Rationale for Exporting Power

In order to fulfill its mandate, MH has, by design, much more installed capacity than Manitoba demand and therefore is in a position to produce electricity in excess of what is consumed in Manitoba. This is not a recent circumstance, but has been the case for much of MH's history. For example, in fiscal 2008/09, MH hydro had an installed system capacity of 5,480 MW with a Manitoba firm peak demand (occurring in the winter) of 4,477 MW. In the same fiscal year, the total energy supplied by MH's system (other than isolated generation capabilities in remote communities) was 34.5 TWh whereas Manitoba consumption was 21.3 TWh *(Source: Manitoba Hydro 2009 Annual Report).*

A key consideration in MH's capacity planning process is the variation in water flows. For meeting its projected load, MH relies only on dependable energy, which is the energy that is projected to be available in the lowest flow year. Additional or surplus energy may be available in most years, but this cannot be counted on to meet MH's firm loads and firm export commitments.

Because of the need to plan to provide energy on a firm basis, the amount of dependable energy available, rather than the amount of installed capacity, becomes the key planning criteria. Another way of saying this is that the MH system is energy limited, rather than capacity limited. In this framework, dependable energy is the energy metric of relevance.

The addition of new hydroelectric generating capacity generally increases the amount of dependable energy available. This reflects the fact that the installation of new hydro generating plants allows MH to extract more energy from a given amount of water flowing into the MH system. More precisely, the addition of a new hydroelectric plant allows MH to capture additional "head", or energy from the drop in the elevation of water, as a unit of water flows down to Hudson Bay. MH defines dependable energy as the hydroelectric power available under the lowest river flow conditions in the historical record, and also includes energy sourced from non-hydroelectric sources, including MH thermal stations, wind farms with long-term contracts, and energy imports. (These other energy sources remain a very small share of Manitoba's total production).

Although dependable energy is the key system constraint, MH's financial plans need to take account of the fact that more energy will generally be available in anything other than a low-flow year. This additional energy is known as surplus energy. The amount of surplus energy available in any year varies widely. Financial plans are developed by averaging the results of alternative water flow scenarios. Water flow scenarios are based on the historical record of water flows. The average amount of surplus energy available across the various water flow scenarios can be referred to as the expected surplus energy. Surplus energy has generally been sold on a short-term basis in export markets. These short-term sales, which are linked to surplus energy, are referred to as "opportunity sales".

In high flow years, MH may have insufficient capacity to use all of the available water flow. This can lead to the "spill" of some of the water now flowing, where such water bypasses the generating equipment. Generating capacity is not generally a constraint in meeting MH winter loads. The objective of having sufficient dependable energy resources has led to an amount of installed capacity that is greater than current winter loads in Manitoba.

For capacity planning purposes, MH has established the following power resource planning criteria *(Source: Manitoba Hydro Policy G195, Generation Planning)*:

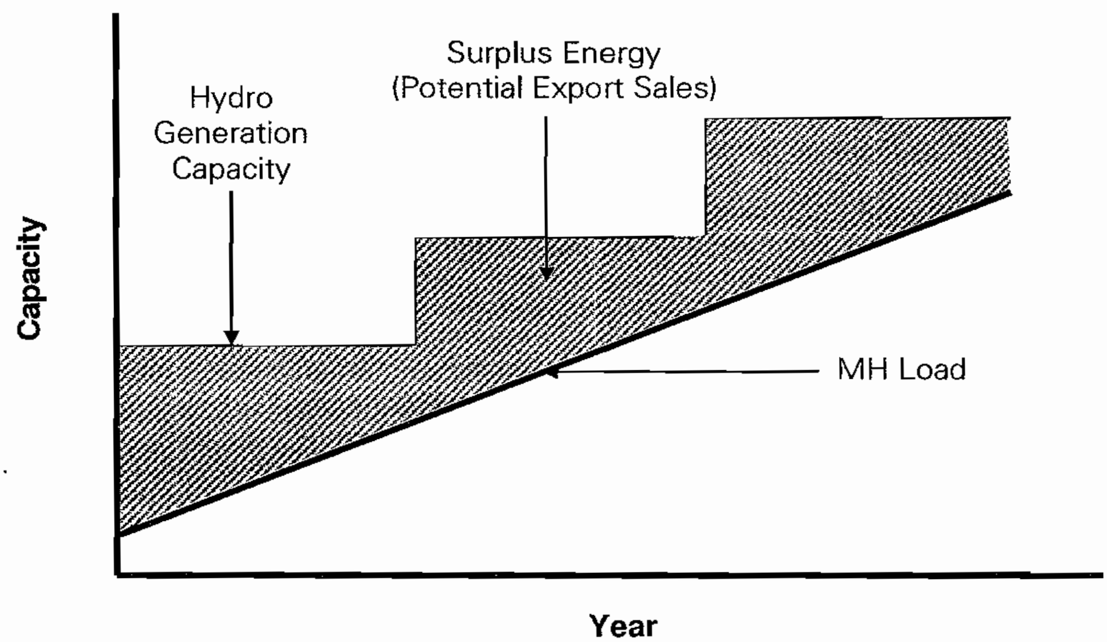
- *"Capacity Criteria — Manitoba Hydro will plan to carry a minimum reserve against a breakdown of plant and an increase in demand that is 12% above the*

Manitoba forecast peak demand each year plus the reserve required by any export contract in effect at the time. (E.M.C. 73.03)

- *Energy Resource Planning — The Corporation will plan to have adequate energy resources to supply the firm energy demand in the event that the lowest recorded coincident river flow conditions are repeated. Planning studies, to meet the firm energy demand, may include up to a maximum of 10% of the energy demand in Manitoba to be supplied from the energy reserves on interconnected utilities, provided an energy purchase contract is or will be in effect during the time being studied. (E.M.C. 177.05)"*

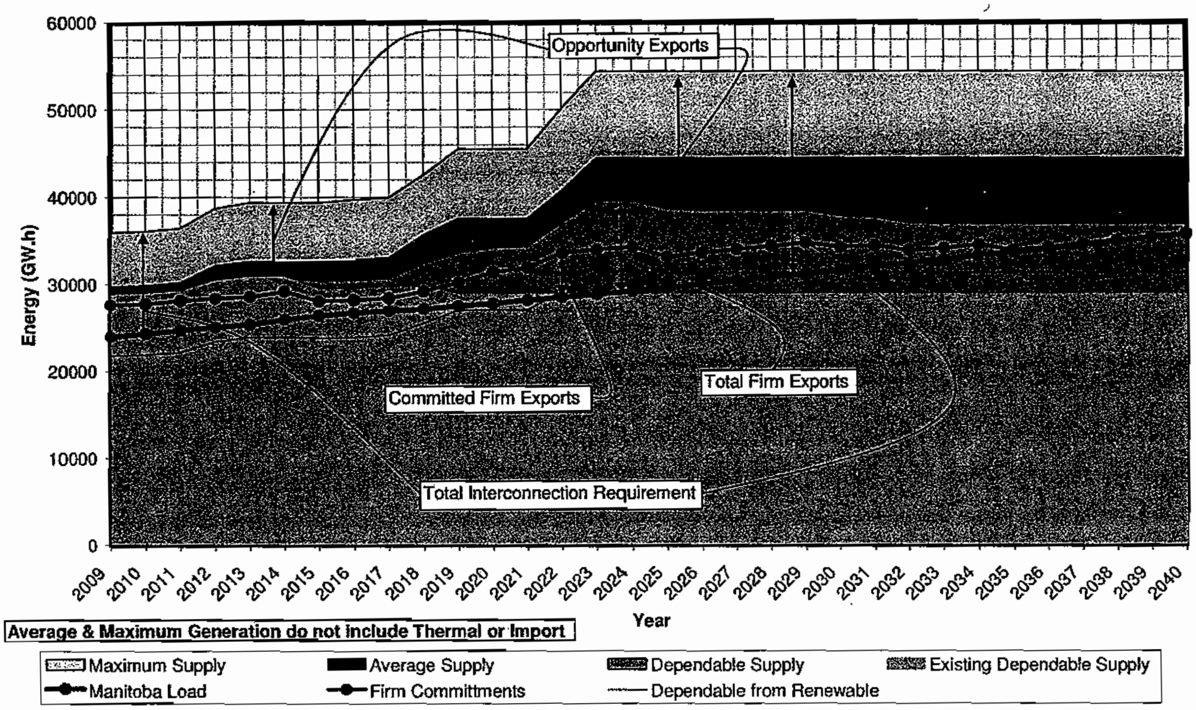
In addition to the surplus capacity required by MH's power resource planning criterion, another key reason that MH has surplus energy production capability is that hydroelectric plants tend to be built in "chunks", i.e., there are large capacity additions at a single point in time to take advantage of economies of scale in plant development, whereas Manitoba load tends to grow in a steady manner year over year. Thus, every time a plant is built, MH will have excess dependable energy until such time that the incremental Manitoba load "catches up" to the incremental resources added to the system. This excess dependable energy can be used by MH to generate firm energy that is surplus to Manitoba requirements, and that can be exported, as illustrated in the graph below.

Manitoba Hydro Generation Energy vs. Load



Accordingly, a key consideration for MH in planning new generation capacity additions is finding a market for the surplus dependable energy that will be generally available for an initial period, as well as for the surplus energy that will be available on an ongoing basis. The magnitude of this issue can be appreciated from the following Exhibit 4-1 reproduced from MH's 2009/10 resource plan.

Exhibit 4-1: System Energy Supply



Source: Manitoba Hydro 2009/10 Power Resource Plan

As shown in Exhibit 4-1, the projected Manitoba load (i.e., the red line) is significantly below the maximum potential supply (i.e., the topmost line). The maximum potential supply reflects the energy available in a high flow year.

Note that Exhibit 4-1 compares supply and demand for energy on an annual basis. To gain a further understanding of MH's potential for producing energy in excess of Manitoba needs, it is necessary to also consider Manitoba's system characteristics. Key factors in this regard are:

- Average demand is much lower than peak demand. For example, in 2009, average domestic demand was only 2,426 MW or 54% of peak. (Average domestic demand is calculated as annual domestic energy demand/all hours.) Thus there are large time periods within a year when MH has excess capacity which is available for export energy production.

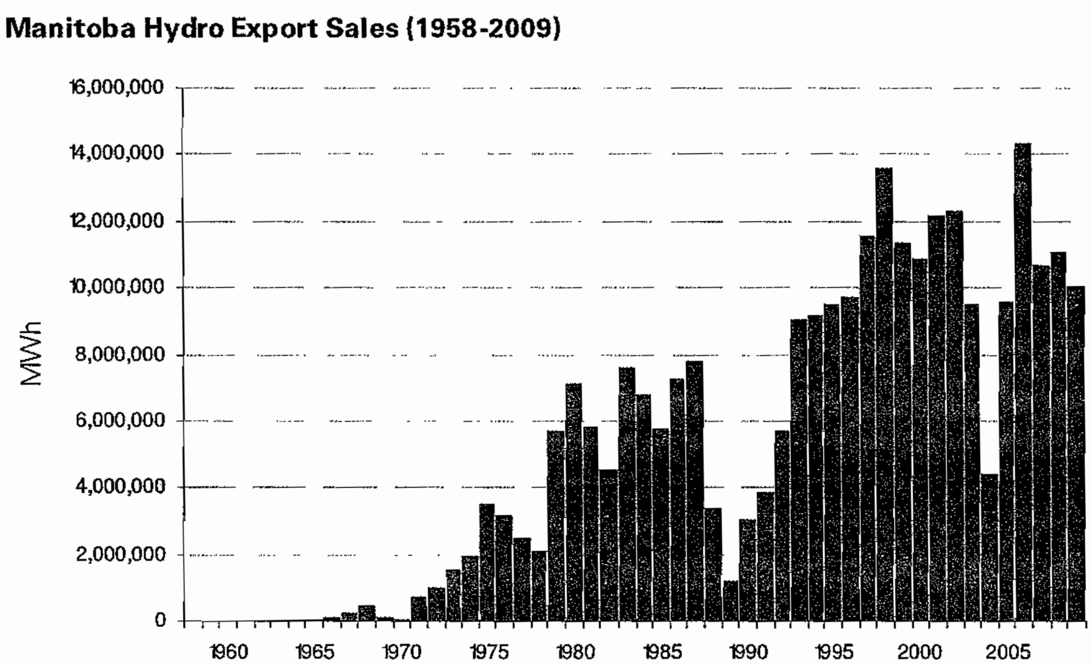
- MH's summer peak is significantly lower than its winter/annual peak and since MH's principal export market of MISO faces its peaks in the summer, there is potential for diversity exchange related export sales (in which MH buys energy in its peak winter season from a counterparty and sells energy back to the counterparty in the counterparty's peak summer season).

- MH has limited water storage capacity relative to its variability in water flows as compared to other major hydro-based Canadian electric utilities such as BC Hydro and Hydro Quebec. This is primarily a function of geography and is due to the relative topographical uniformity of the Manitoba terrain.

Accordingly, due to these system characteristics, MH has considerable potential to generate surplus energy for which it either has to find an export market or spill water to the extent it cannot.

MH export sales are managed by Power Sales and Operations (PS&O) and are a significant source of income for MH. In fiscal 2008/09, export sales totaled $623 million with 79% derived from sales to the US market (primarily to entities in the MISO market) and 21% from sales to Canadian markets (primarily Ontario and Saskatchewan/Alberta). In fiscal 2008/09, export sales comprised 35% of MH's total electricity revenues (*Source: Manitoba Hydro 2009 Annual Report*). Exhibit 4-2 illustrates MH's historical export volumes.

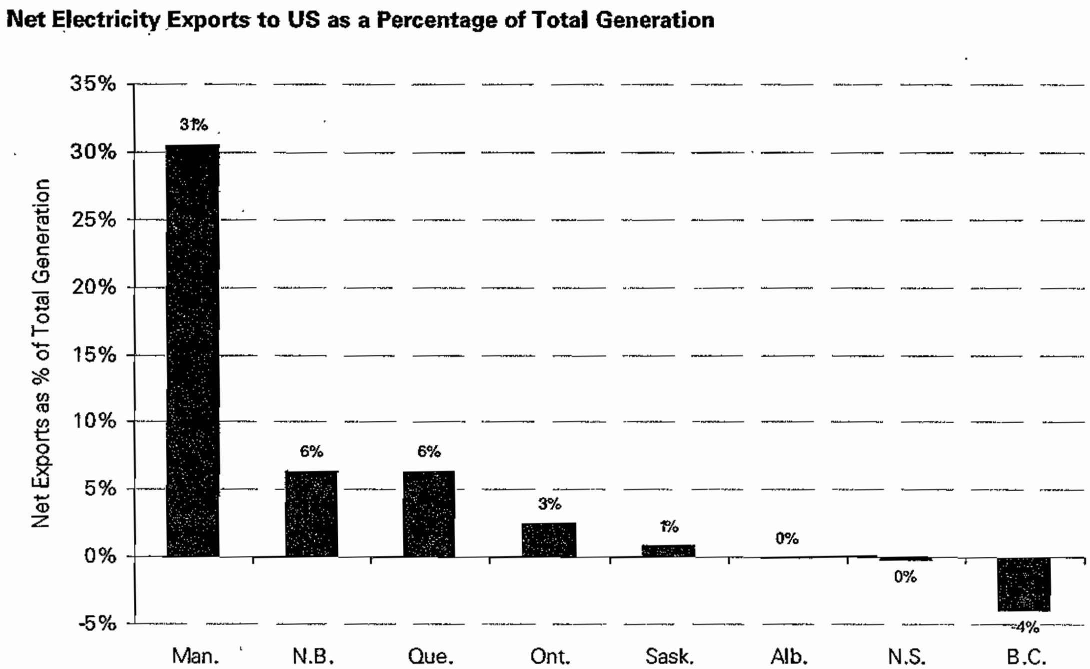
Exhibit 4-2: Manitoba Hydro Export Sales



Source: Manitoba Hydro data

MH is not alone in this regard; other Canadian utilities are also major exporters. MH's largest export markets are customers in the United States (US). Though the US is a key export market for other major Canadian utilities as well (e.g., Hydro Quebec and BC Hydro through Powerex), as shown in Exhibit 4-3, exports to the US represent a considerably larger share of total generation for MH than for other major Canadian utilities.

Exhibit 4-3: Electricity Exports to the US as a percentage of Total Generation



Source: Statistics Canada, 2007 Electric Power Generation, Transmission and Distribution Report.

The considerably higher proportion of export sales to the US for MH reflects the following:

- The variability in MH's water volumes, which results in surplus energy that must generally be sold in export markets given the fact that it cannot be relied upon to serve MH firm loads.

- MH's practice of pre-building required capacity additions in order to earn incremental earnings that can be used to offset MH's domestic rates.

- The large size of new capacity additions relative to load growth in any given year, which results in additional surplus energy in the initial years of a new facility's operation.

Accordingly, the question is not whether MH should participate in the export sales markets but how it should participate. The next section analyzes MH's export sales strategy, focusing in particular on the rationale for using long-term sales contracts.

4.5 Manitoba Hydro's Rationale for Long-term Contracts

At the extremes, MH has two basic mutually exclusive options to sell its surplus energy in the export markets, each with its own risk-reward profile:

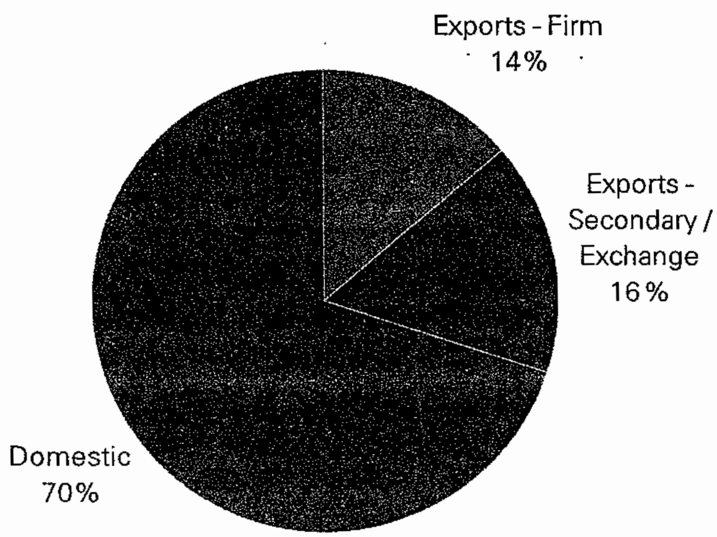
- Sell all the excess energy as spot sales (e.g., MISO DA and RT markets). Key risks that MH takes on under this option include:
  - "missed opportunity regret" risk (spot prices may turn out to be below the price that would have been available under contract);
  - spot price volatility risk resulting in revenue volatility and times when spot prices may drop resulting in a revenue deficiency relative to the fixed costs of MH leading to a corresponding rate increase for Manitoba ratepayers;
  - sales volume risk (there may not always be enough transmission capacity south of the US border for the available excess energy);
  - credit risk; and
  - foreign exchange risk (for cross-border sales).
- Sell all the excess energy at fixed price short-term and/or long-term contracts. Key risks that MH takes on under this option include:
  - "sellers regret" risk (spot prices may turn out to be above the contractual fixed price);
  - sales volume risk (there may not always be enough transmission capacity, especially for short-term contracts, or a drought results in MH having to purchase replacement energy to fulfil its contractual obligations leading to a corresponding rate increase for Manitoba ratepayers);
  - credit risk;
  - foreign exchange risk (for cross border sales); and

– amplified drought risk (to the extent contracts are for firm amounts of energy).

Combinations of the two basic options (e.g., a combination of spot market and fixed price short-term/long-term contracts) are also available. Key MH's risks in doing so would fall somewhere in between the risks of the two above options based on the actual combination.

MH has chosen to export market its surplus energy using a combination approach of spot sales and short-term/long-term contracts. Over the last decade, approximately 30 percent of MH's hydroelectric production has been used for export sales as shown in Exhibit 4-4, with slightly under one-half of those exports in contractual firm sales and slightly over one-half of those exports in opportunity sales.

Exhibit 4-4: Manitoba Hydro's Average Sales Distribution 2000-2007 (GWh)

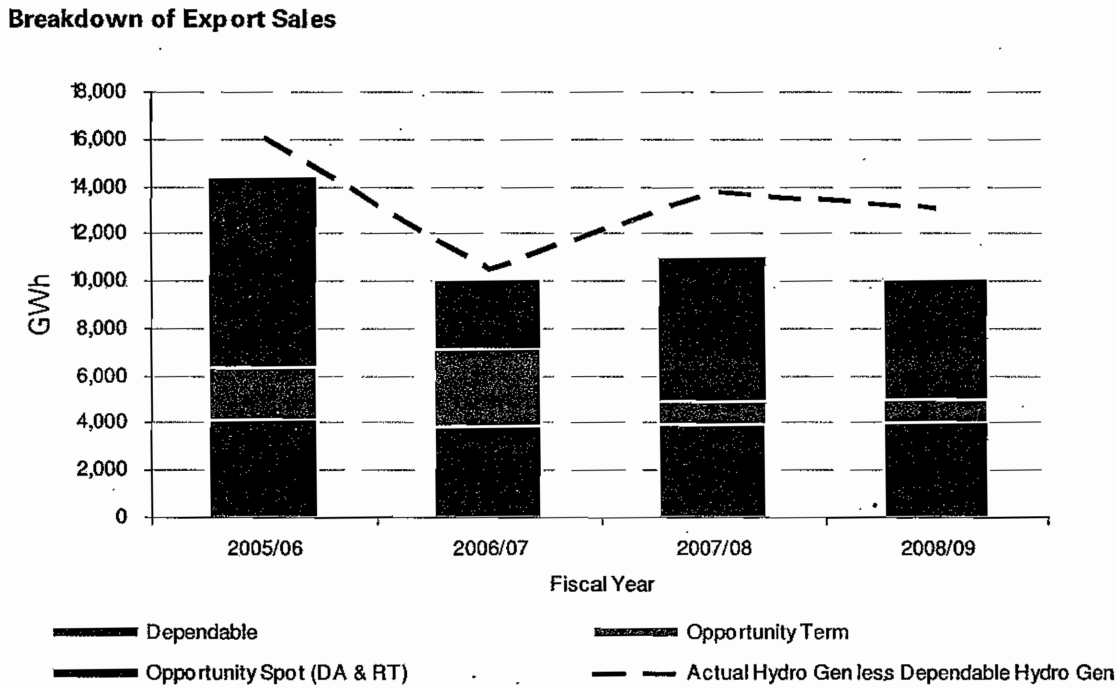


Source: Statistics Canada, 2000-2007 Annual Electric Power Generation, Transmission and Distribution Reports.

Note: Exports-Firm approximately correspond to MH's contractual firm sales while Exports-Secondary/Exchange roughly correspond to opportunity sales, for example, spot sales on the day ahead and real time markets.

A further breakdown of MH export sales is provided in Exhibit 4-5.

Exhibit 4-5: Breakdown of Manitoba Hydro's Export Sales 2005/06 to 2008/09



Source: derived from Manitoba Hydro data.

As illustrated in Exhibit 4-5 above, actual hydro generation from 2005/06 through to 2008/09 was always greater than dependable hydro generation and in all years long-term sales represented 40% or less of the total export sales.

MH's rationale for entering into fixed price firm long-term sales commitments as part of its power sales mix can be summarized as:

- Risk mitigation;
- Securing access to firm transmission; and
- Lower rates for Manitoba ratepayers.

We have obtained this understanding through our review of documents and interviews with MH personnel, case studies of other utilities, use of one of our sub-consultants and our industry knowledge. The remainder of this section assesses MH's rationale.

4.5.1 Risk Mitigation

One of the main elements of MH's rationale for entering into fixed price firm long-term sales commitments is that doing so represents effective risk mitigation. In assessing this element of the rationale, the following are addressed in this section:

- Risk mitigation through the use of long-term contracts;
- Assessment of risk mitigation using long-term contracts; and
- Alternatives to long-term contracts to mitigate risk.

4.5.1.1 Risk Mitigation through the Use of Long-term Contracts

The argument that MH's long-term contracts help mitigate its risks is essentially as follows:

- *Stability and matching of cash flows* – MH has long-term financing needs for its capital-intensive system expansion. These financing obligations, primarily long-term fixed-rate debt, give rise to significant fixed-debt service requirements. The relatively predictable, steady long-term revenue derived from long-term sales contracts matches this need. Said differently, having a relatively predictable and steady revenue stream reduces MH's revenue volatility which, in a capital-intensive industry, is an especially desirable outcome to pursue in that it can reduce the risk of having "liquidity events" (e.g., severe drought leading to cash flow dropping below debt service requirements). When a liquidity event occurs, it may not be possible to rely on internally generated funds and it may be extremely costly to fund with external financing sources (if they can be funded at all); as a result, MH should manage the risks of liquidity events to minimize their likelihood and the stress of trying to access external financing sources when the firm is at its most vulnerable.

- *Diversification* – By including long-term contracts, MH is able to diversify its export sales mix and thus reduce its risk of over-reliance on a more limited set of markets (i.e., MISO spot markets and the use of short-term contracts). There is considerable finance literature with arguments supporting diversification and diversification is well established as a desirable risk management outcome.

- *Foreign exchange risk hedge* – The revenue derived from long-term sales contracts is US dollar denominated. It thus serves as a natural hedge to the foreign exchange risk arising from the portion of MH's long-term debt that is US dollar denominated.

4.5.1.2 Assessment of Risk Mitigation using Long-term Contracts

In assessing MH's rationale for entering into long-term contracts to help mitigate risk, KPMG has reached the conclusion that it concurs with MH's view that long-term contracts can serve as an element of an effective risk mitigation strategy.

Were all of MH's surplus energy sold in short-term increments, the price received for that power would be highly uncertain and volatile, thus exposing the Manitoba ratepayer to potential rate shock in low export price periods. Exhibit 4-6 illustrates the considerable annual volatility in recent market prices. Prices for the period 1997 to 2005 are for the Mid-Continent Area Power Pool (MAPP); prices since are from MISO.

Exhibit 4-6: U.S. Midwest Power Prices 1997-2009

Annual Wholesale Power Prices, 1997 - 2009				
Year	On Peak Power Prices (Nominal US$)	Spot Prices (2009 US$/MWh)		
		On-Peak	Off-Peak	All-Hours
1997	22.1	29.7	14.4	21.6
1998	29.2	38.3	15.1	26.1
1999	39.5	50.6	13.9	31.2
2000	39.0	48.7	18.5	32.0
2001	37.5	45.7	18.5	31.3
2002	27.8	33.0	16.8	24.4
2003	44.7	51.8	20.6	35.3
2004	46.6	52.7	23.3	37.1
2005	58.9	65.0	23.1	42.5
2006	54.3	58.4	29.5	42.9
2007	62.4	65.6	34.1	48.8
2008	59.6	61.1	29.3	44.1
2009	29.6	29.6	15.6	22.1
Standard Deviation	**13.4**	**12.6**	**6.5**	**8.9**
Average Price (1997-2009)	**42.4**	**48.5**	**21.0**	**33.8**
Average 1997-2004	**35.8**	**43.8**	**17.6**	**29.9**
Average 2005-2009	**52.9**	**55.9**	**26.3**	**40.1**

Source: 1997-2004 ICF Independent Review of Manitoba Hydro Export Power Sales and Associated Risks (2009 09 11); 2005-2009 MHEB RT Monthly Average Prices

We have also examined what others have said on this topic. Many electric utilities need to consider the role of long-term contracts in risk mitigation and the issue has been studied. In particular, KPMG notes an Amicus Curae brief[6] by twenty prominent economists, including Nobel Prize winner Vernon L. Smith that discusses, among other things, the role of long-term contracts in mitigating risks for utilities.

In this brief, opining on the California electricity crisis of 2000-2001, these economists argue that long-term contracts are key risk management tools writing that:

"commodity buyers and sellers often enter into long-term forward contracts to manage risk. A forward contract is an agreement for the delivery of a commodity in the future at a specified price... By agreeing to a fixed price ahead of time, rather than waiting to purchase the commodity at some unknown price in the spot market, buyers can "hedge" their financial risks... Sellers correspondingly gain the certainty of a guaranteed income stream regardless of changes in demand... Forward contracts thus are all about providing certainty—avoiding risk—for both sides. Because risk avoidance is desirable in its own right, firms will often enter into long-term contracts even where the contracts are not expected to save the purchaser money in comparison to buying exclusively on the spot market. Indeed, if firms are sufficiently risk averse, they may be willing to pay more under a long-term contract than they expect to pay on the spot market."

The economists further state that the need to manage risk by ensuring contract certainty is particularly important in the energy industry:

"Energy markets are inherently volatile. Because dramatic price swings threaten substantial financial risks for buyers and sellers, enforceable forward contracts are particularly important to hedge risk in those markets."

They continue their argument as follows highlighting the volatile nature of electricity spot markets:

"Multiple factors contribute to that volatility. Unlike other commodities, energy cannot be economically stored in large quantities.... As a result, supply and demand must be in constant equilibrium—there is no electricity inventory that could be used to meet sharp increases in demand. Additionally, the demand for electricity is

[6] *Amicus Curae brief Nos. 06-1457, 06-1462, in the Supreme Court of the United States in the matter of Morgan Stanley Capital Group Inc., Petitioner, v. Public Utility District No. 1 of Snohomish County, Washington, et al., Respondents, and Calpine Energy Services, L.P., et al., Petitioners, v. Public Utility District No. 1 of Snohomish County, Washington, et al., Respondents.*

extremely inelastic in the short term, even though a wide variety of unpredictable factors such as temperature may cause wild fluctuations in usage. As a result, a "properly functioning, fully-competitive electricity market is likely to yield market prices that vary by a factor of ten or twenty to one in a single day... Long-term contracts are essential to allow electricity providers to weather the uncertainties of the inherently volatile market in which they participate. Reflecting that, forward contracts "represent the majority of instruments used for risk management" in the electricity market.... The need for contract certainty to deal with price volatility has been amplified by the shift toward a market based pricing regime. In a cost-based regime, energy suppliers have little incentive to reduce costs or limit production to the level of consumer demand, and accordingly often have excess capacity.... That excess capacity imposed wasteful costs that were passed on to consumers..... Market based regimes reduce those inefficiencies by inducing suppliers to calibrate supply to demand more closely. One result of that efficiency improvement, however, is that there tends to be less excess capacity to dampen volatility. Long-term contracts allow firms to manage the greater volatility that accompanies market-based pricing by guaranteeing that at least part of their needs will be met at a fixed price regardless of short-term conditions."

Entering into long-term contracts mitigates price risk but may expose MH to other risks. The primary risk in doing so is volume risk.

Volume risk refers to the risk that MH commits to selling firm energy in a long-term contract that it may be unable to deliver (e.g., due to a drought). We understand that MH addresses its volumetric risk by not committing the bulk of its export sales volumes until it is reasonably sure the water will be available[7]. It would be risky to promise these volumes to the market in the absence of reasonable certainty. However, as illustrated in Exhibits 4-1 and 4-4, substantial energy volumes have been and are projected to be available for export sales in almost every year.

[7] *This appears to be true for both decisions to commit to new long-term firm power sales as well as for short-term surplus energy sales. For long-term firm power sales, our understanding is that MH does not enter agreements above the level of dependable energy it has calculated for the system. On the short-term power sale side, it appears that MH is risk averse in the manner by which it calculates the amount of surplus energy available and the timing of commitment to selling that surplus energy.*

4.5.1.3 Alternatives to Long-Term Contracts to Manage Risk

One could argue that MH could use financial instruments such as weather derivatives, and other types of options, and power contracts that settle financially rather than physically to hedge its price risk. It is fairly common for integrated electric utilities to use financial engineering tools to manage price risks. However, the use of financial instruments is complex and their use by electric utilities needs to be quite specific to the application and to the utility. For example, one must decide between standardized contracts which have greater liquidity but (in general and definitely for MH) increased basis risk, and custom products which have less basis risk but high transaction costs. Hence, there is no standard practice in hedging power market risks financially for electric utilities.

Of particular relevance to MH is its potential ability to manage its drought risk using weather derivatives. However, managing drought risk with weather derivatives is fraught with liquidity risk for MH. Further, even the most liquid weather derivatives available may not be suitable for MH's purposes.

Weather derivatives are primarily sold in the Over-the-Counter (OTC) markets in the form of swaps or options. OTC market participants include trading groups, insurance and reinsurance companies, brokers, and end-users. Although most trading in the weather market is still over-the-counter, standardized weather derivatives contracts are now listed on the Chicago Mercantile Exchange (CME), the Intercontinental Exchange (ICE) and the London International Financial Futures and Options Exchange (LIFFE). In consultation with our sub consultant NERA, at the present time we find weather derivatives to be illiquid in both OTC markets and Exchanges. For example, for the period April 2008 to March 2009, the notional amount of weather derivatives traded on the CME fell by 53% ($15BN from $32BN). With such limited trading volume, the CME cannot support a highly liquid marketplace at all traded locations. Further, we note that the CME weather markets for Canadian locations never garnered a liquid and transparent market. For example, on and around February 22, 2010, there was no transaction activity and no open weather derivatives at any CME Canadian location.

Further, we find that though weather derivatives can be based on natural phenomena such as the amount of precipitation, snowfall and outdoor temperature, the majority of derivative options available for purchase on OTC and Exchange markets are options on outdoor temperature levels. For example, while there is a snowpack derivative product offered for Minneapolis-St. Paul, there are no recent transactions and the market is effectively moribund. Thus, for MH's purposes of managing volume risk, there is no liquid weather derivative available.

Other financial instruments, such as electricity futures and options, pose their own set of challenges and liquidity requirements. For example the requirement for parties to post collateral, and that collateral requirement do change as either market prices move or the credit quality of the party changes. The liquidity of such financial instruments, purportedly one of their main benefits, can be questionable as well although perhaps not to the same extent as for weather derivatives. Based on our analysis, liquidity in standardized electric power financial products is a relative term, as it is particularly difficult to find counterparties for even 12 to 36 month deals. These financial markets have waxed and waned in their liquidity. In recent years, investment banks provided much of the trading counterparties to these deals, but many of these banks have recently left the market.

Overall, we therefore do not find that MH could credibly use financial instruments such as weather derivatives, and other types of options, and power contracts that settle financially rather than physically to hedge its price risk.

In summary, our assessment of MH's rationale that entering into long-term contracts represents effective risk mitigation leads us to the conclusion that MH has been prudent from a risk management perspective by using long-term contracts to align the cash outflows associated with constructing, operating and financing the new facilities with the cash inflows from such long-term contracts and by diversifying its export sales mix.

4.5.2 Securing Access to Firm Transmission

One of the main elements of MH's rationale for entering into long-term contracts is that it provides MH access to firm transmission capacity within the jurisdiction served by the counterparty and the network to which it belongs. In the context of the long-term contracts with US counterparties (which are the only counterparties with whom MH has long-term contracts), this capacity is within the MISO footprint. MH argues that access to firm transmission serves both as an effective risk management strategy and helps keep rates low for Manitoba ratepayers because:

- Firm transmission brings with it increased capacity to import power from MISO in a drought situation. Since MISO has primarily thermal generation, it remains largely unaffected by a drought in terms of energy production. Thus MH argues that it can reduce its drought risk by:

- accessing the MISO marketplace to import electricity to offset the hydroelectric energy that is not available within its system as a result of a drought, and/or

- importing power from MISO at a lower cost than running its own thermal units (the MISO market "heat rate" is generally lower than the heat rate of MH's thermal plants). All of the potential output from a thermal plant is included in the definition of dependable energy. However, this output is not generally required except in cases of low flow. In practice, when low flow occurs, the cost of running these plants can often be avoided by opportunity imports in the event that transmission capacity is available.

- potentially avoiding some of the capital costs associated with additional thermal generation or hydro generation[8] that is required to provide back-up or firming capacity.

Further, increased import capability helps MH mitigate the risk of power shortages in Manitoba if the Provincial north-south transmission capability fails (e.g., ice storms).

- Firm transmission provides MH increased ability to sell surplus power in on-peak hours. Transmission is typically congested in on-peak hours leading to non-firm transmission being increasingly curtailed by MISO through TLR orders (Transmission Loading Relief orders). This increasingly shifts MH surplus sales into off-peak hours where transmission congestion can be less. Since on-peak prices are typically higher than in off-peak hours, access to firm transmission in on-peak hours means MH can earn comparatively higher revenue from its surplus power sales.

4.5.2.1 Assessment of risk mitigation through securing access to firm transmission

In assessing this element of MH's rationale for entering into long-term contracts, KPMG has reached the conclusion that it concurs with MH's view that providing access to firm transmission capability serves as an effective risk management strategy.

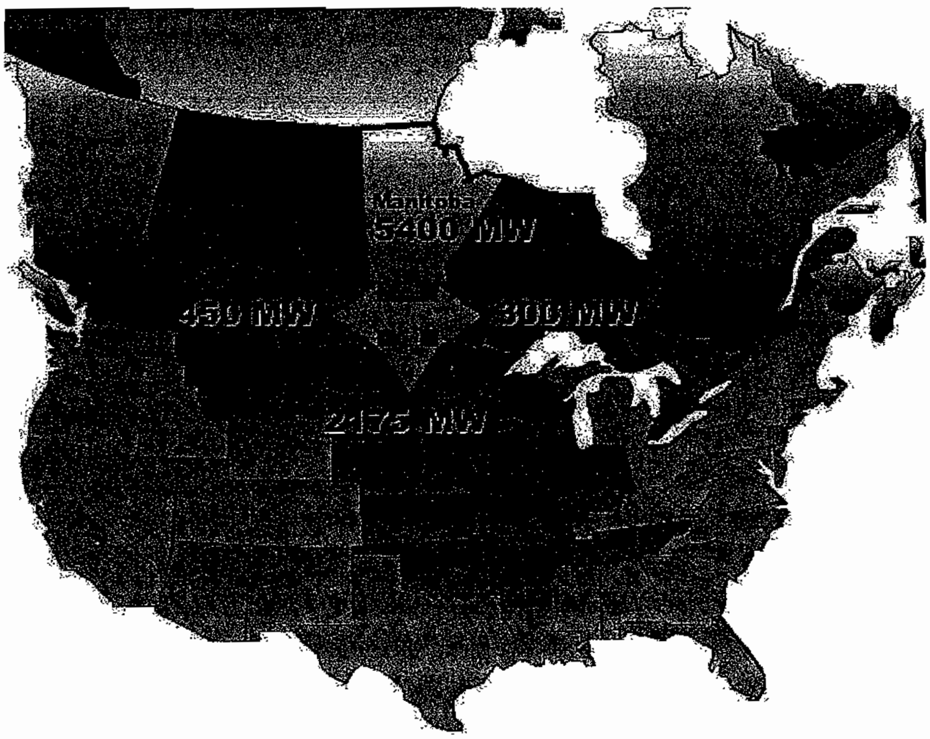
---

[8] *In the event of a drought, adding more hydro plants on a river system mitigates the impact of the drought by allowing the system to capture more of the potential water head.*

As described above, MH argues that access to additional firm transmission is a significant benefit to MH[9]. We understand that extra-provincial sales or purchases of electricity are achieved at Manitoba's borders through a number of two-way transmission connections to the US, Ontario, and Saskatchewan.

The maximum MW capability of this transmission is as shown in Exhibit 4-7.

Exhibit 4-7: Maximum MW Transmission Capability

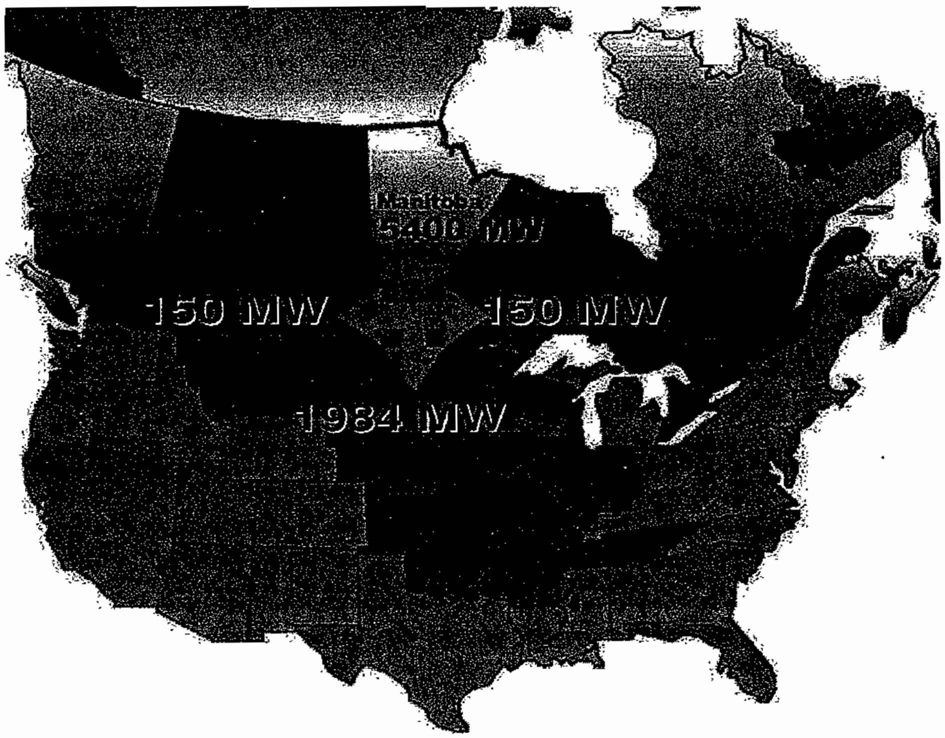


Source: Manitoba Hydro Division Manager, Power Sales and Operations, presentation "New Hydro ... Part of the Solution", Slide 10.

[9] *See **Appendix F** for a MH document on this issue titled "Now is the time – A strategic Opportunity".*

However, in practice, MH has indicated that actual transmission availability is lower for a variety of technical reasons. Exhibit 4-8 shows the summer scheduling on the transmission interconnects.

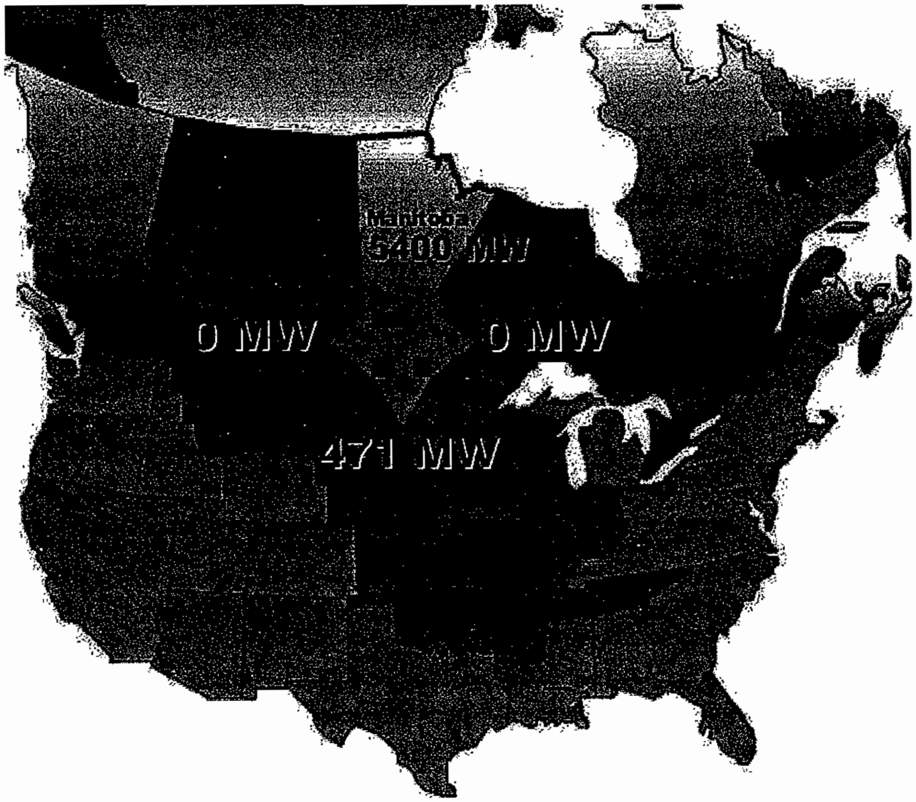
Exhibit 4-8: Summer Scheduling Transmission Interconnect Availability



Source: Manitoba Hydro Division Manager, Power Sales and Operations, presentation "New Hydro ... Part of the Solution", Slide 11.

Moreover, MH has indicated that it has limited control over transmission scheduling outside Manitoba as illustrated in Exhibit 4-9.

Exhibit 4-9: Transmission Scheduling Control

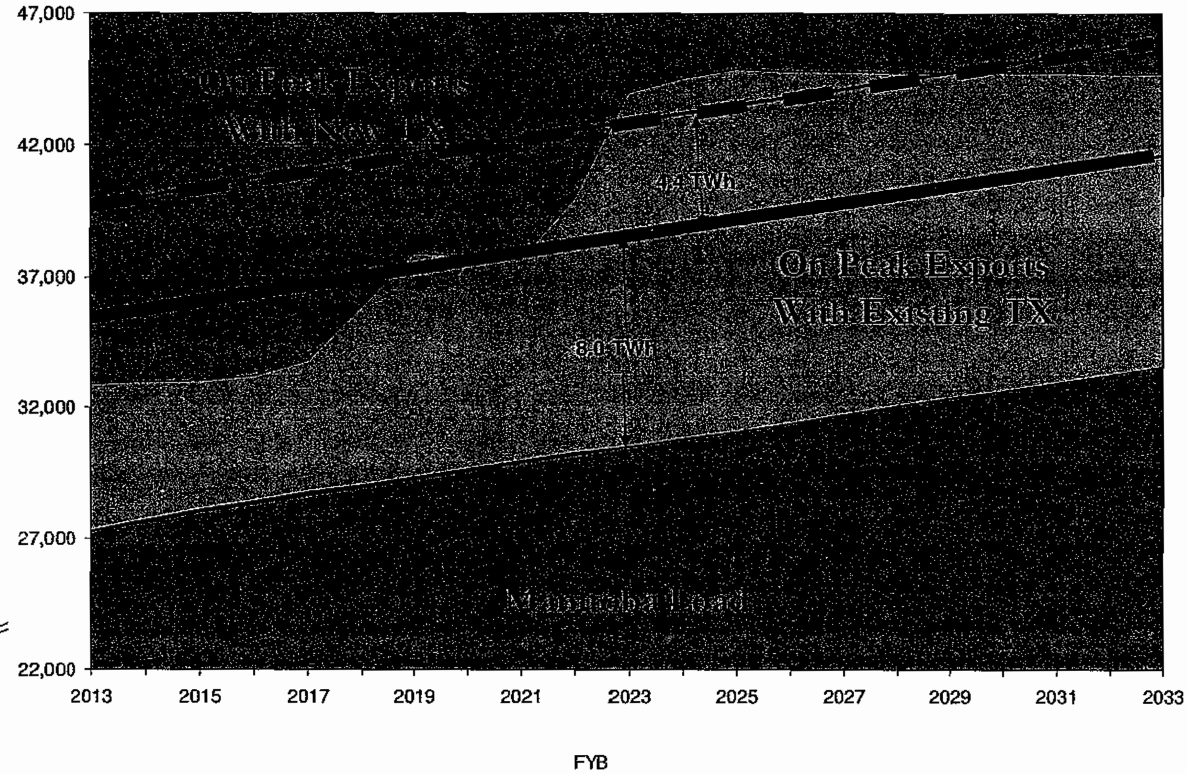


Source: Manitoba Hydro Division Manager, Power Sales and Operations, presentation "New Hydro ... Part of the Solution", Slide 12.

As illustrated in Exhibits 4-7 to 4-9, MH's theoretical transmission interconnect capacity is not only reduced by technical reasons but also due to lack of scheduling control outside of its service territory. For example, MH has 100% control over the transmission to the US border but just over 20% of the theoretical interconnect capacity south of the border. Since there is no load at the border itself, MH export sales into MISO largely depend on being able to secure firm transmission to a load center (e.g., MINN hub - Minneapolis).

Exhibits 4-7 to 4-9 represent MH's current circumstances. As MH adds hydro capacity, it will require increasing access to firm transmission in order to export surplus energy. Lack of firm transmission does not preclude export sales but exposes MH to the risk that it may not have sufficient transmission to sell its power at load centers, e.g., through TLR orders. Exhibit 4-10 illustrates MH's increasing new interconnection requirement based on median water flows and further illustrates that in the absence of adding additional transmission capacity, a considerable amount of MH's potential export sales are at risk due to insufficient transmission capacity.

Exhibit 4-10: Manitoba Hydro Interconnection Requirements



Source: Manitoba Hydro Division Manager, Power Sales and Operations, presentation "New Hydro ... Part of the Solution", Slide 13.

Long-term contracts facilitate access to firm transmission within MISO. As a condition of entering into long-term contracts backed by power produced from new hydro facilities, MH's counterparties are required to invest in new transmission from the Manitoba border into the MISO market and further to grant MH firm transmission rights on the incremental transmission capacity.

4.5.3 Lower Rates for Manitoba Ratepayers

Another element of MH's rationale for entering into long-term contracts is that they generate economic returns that will benefit Manitoba ratepayers, through lower rates. In particular, economic returns result from MH's ability to sell additional energy in export markets, often at premium prices. Long-term contracts, which can be written against the dependable portion of additional energy available, benefit the economic case for a new hydroelectric plant through two mechanisms:

- Energy under contract should receive a higher price than energy from spot market sales. This reflects the value of firm supplies and price certainty to potential contract counterparties.
- The presence of long-term contracts facilitates MH's ability to get external debt financing. This financing is likely to be available in more quantity and/or at lower cost than in the absence of long-term contracts. This may improve the economic case for a new hydroelectric dam, in addition to improving MH's ability to fund the project and/or advance its construction relative to an alternative scenario in which contracts are not established.

The economic benefit of a new hydroelectric facility is established by analysis of the impact of the facility on net system costs at MH. Net system costs reflect costs borne by MH ratepayers, taking into account net revenues from export activity. Economic benefits are quantified in net present value (NPV) terms.

4.5.3.1 Assessment of lower rates for Manitoba ratepayers

In assessing this aspect of MH's rationale for entering into long-term contracts, KPMG concurs with MH's view that entering into long-term contracts can provide net benefits to MH and therefore lower rates to Manitoba ratepayers.

Hydro power development of the scale planned by MH is very capital intensive. Financing to support capital development of this scale is subject to very rigorous due diligence by prospective lenders. In doing so, a key aspect of the project that lenders assess is the security of the projected revenue stream. A long-term contract with a credit worthy buyer willing to pay firm prices and committing to purchase specified energy volumes provides lenders with considerably greater security than a projected revenue stream from spot sales in which both price and volume are uncertain. As detailed in Chapter 6, MH's long-term contracts to date have been with credit worthy regulated utilities.

KPMG also notes that the 20 economists referred to earlier in this section address this topic in their brief. Specifically, they wrote that *"The energy industry, moreover, is exceedingly capital intensive, requiring enormous outlays for infrastructure development that may take years or decades to recoup. Contracts—particularly long-term forward contracts—are indispensable to provide the certainty necessary to encourage such enormous long-term investments."*

They further observe that *"Vast outlays of financial resources are required for electric power production and delivery. Generation, transmission, and distribution all require years of investment in infrastructure. Those investment costs may not be recouped for decades, particularly in light of the fluctuating "boom" and "bust" cycles that characterize the industry... Electricity producers will not invest the extraordinary resources needed to develop new energy sources without some assurance that they will recoup their investment. Contracts that guarantee future revenue streams can provide that assurance..."*

KPMG also notes a report by the US Congressional Budget Office on the California electricity crisis that stated *"Long-term contracts play a critical role in infrastructure development in other ways as well. A generator of electricity faces high sunk costs upon entering the markets. Long-term contracts... may be used to obtain credit..."*

4.6 Pricing of Power Sold under Long-term Contract

Prices and terms and conditions in a long-term firm power sales agreement are negotiated between the parties. Prices, and terms and conditions, should generally reflect the allocation of risk under the contract as well as the value received by each party. Both parties to the contract will enter into the agreement only if they both perceive that there are "gains (financial and non-financial) from trade," meaning that the contract provides both parties benefits that they perceive are greater than the costs.

Were MH to attempt to extract all of the gains from trade by only selling at the current market price, there would be no transaction because the counterparty would see no gains from trade. Such a result would likely harm the Manitoba ratepayers, as the counterparty would not undertake the investments in transmission on their side of the border, and the market access benefits as a result of increased market access in the event of drought would not accrue to Manitoba ratepayers.

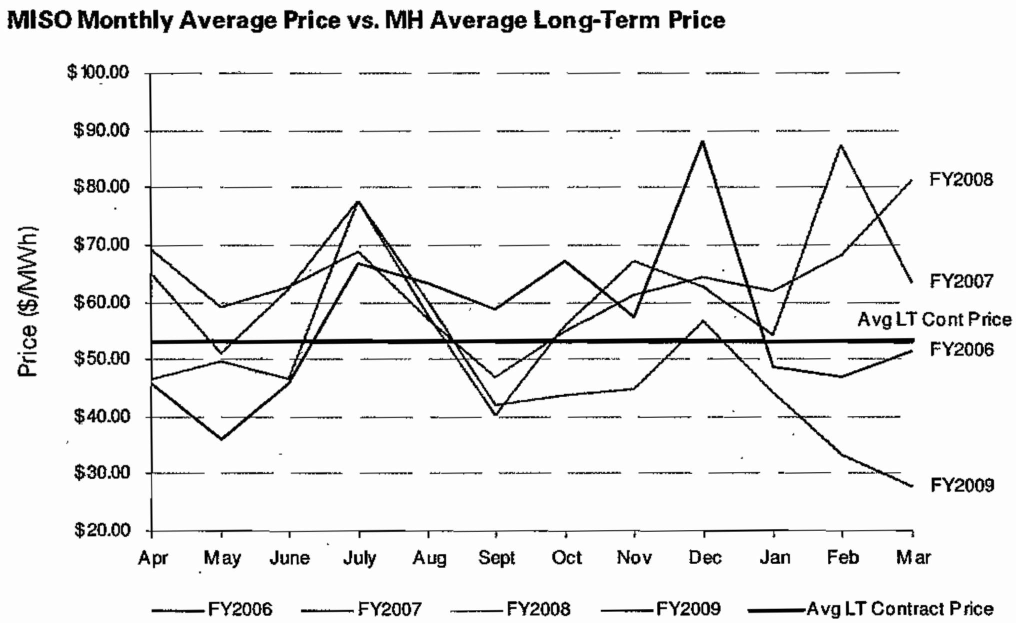
MH has a number of existing and proposed long-term contracts, mainly with Northern States Power (NSP, Xcel Energy), Minnesota Power (MP) and Wisconsin Public Service (WPS)[10]. In these, MH appears to have been generally successful in extracting gains from trade.

In our review of contracts, we found that the revenue earned under MH's existing long-term firm contracts averaged $53/MWh over the period 2005-2009. This is about equal to the average MISO Real Time on-peak price over the same period (at the MHEB node). This close relationship is noteworthy given that some of MH's contracts were signed in the mid-1990s when wholesale prices in MAPP (a predecessor market) were lower. While spot prices have exceeded realized contract prices at certain points in time, a long-term perspective gained through a comparison of average prices better captures the benefits and costs of contracting, particularly since the goal of contracting is to reduce revenue volatility. Because of the recent sharp decrease in market prices in MISO, the benefit of long-term contracting was particularly apparent in the latter part of 2009. Market prices remain low in early 2010.

Exhibit 4-11 summarizes the average historical MISO prices since inception of the MISO market to the average long-term contract prices realized by MH. Exhibit 4-11 also serves to once again demonstrate the historical variability in MISO prices.

[10] *Refer to **Appendices G and H** for summaries of Manitoba Hydro's existing and proposed long-term contracts.*

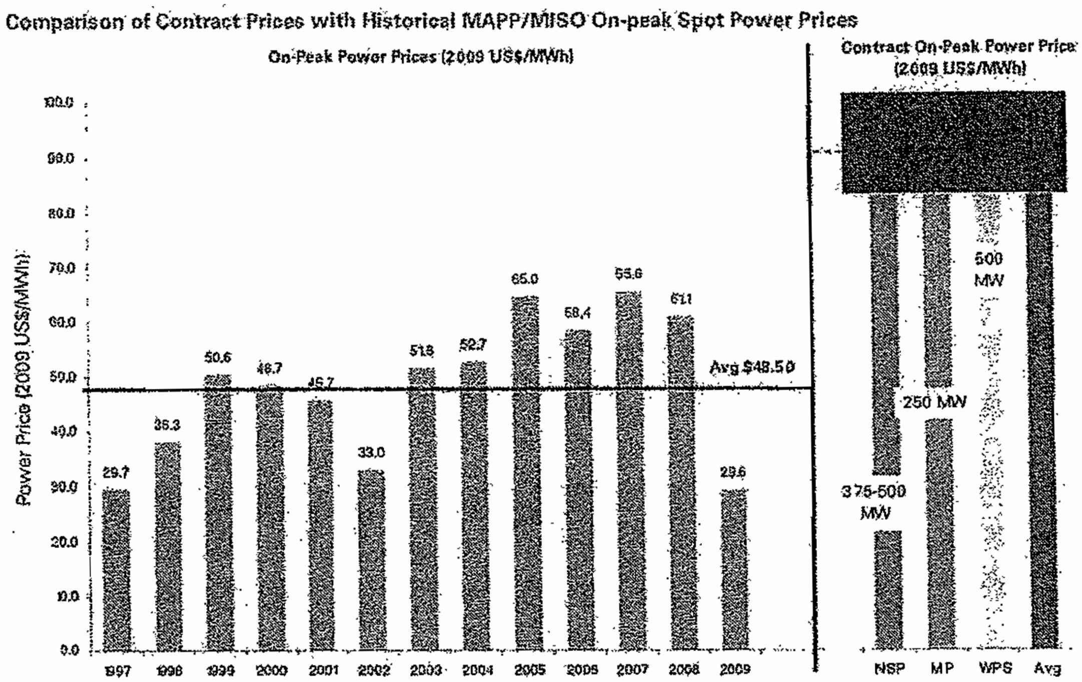
Exhibit 4-11: MISO Monthly On-Peak Prices versus MH Average Long-term Contract Price



Source: KPMG prepared historical MISO MHEB RT price data and MH realized long-term contract average prices.

MH also appears to have been generally successful in extracting a substantial portion of the gains from trade in its proposed long-term contracts as evidenced by a comparison of proposed major long-term contract prices to MISO real time on peak price in the Exhibit 4-12.

Exhibit 4-12: Comparison of Contract Prices with MAPP/MISO On-peak Prices



MH 2.

Source: 1997-2004 ICF Independent Review of Manitoba Hydro Export Power Sales and Associated Risks (2009 09 11); 2005-2009 MHEB RT Monthly Average Prices.

As shown in Exhibit 4-12, the proposed export contract prices are well above historical spot prices (All [redacted] MWh versus $49/MWh). Whether MH has extracted all it could from its counterparties in negotiating long-term firm power sales contracts is easy to second guess. However, the existence of the contracts suggests that both counterparties (the seller and the buyer) saw some gains from trade in the deal; otherwise they would not have entered into the agreement. Whether the buyer would have paid more is a question that cannot be resolved. Clearly, there is some price at which the counterparty would simply walk away rather than do the deal. What price is too high is a question that cannot be easily answered. MH 2.

Future market prices for power are always uncertain. Uncertainty stems from many sources, including the future electricity market structure, load growth, government regulation, capital costs for new generation, fuel costs, and emission costs. Despite these uncertainties, utilities make long-term resource commitments in the form of long-term contracts and construction of new generation facilities. As MH is negotiating long-term power sales agreements, both it and its counterparties may have differing views on these uncertainties, as well as on the risks they pose. In negotiating the terms and price in an agreement, each counterparty is looking to find common ground (a set of terms and price) that allow a deal to be done. MH needs to understand the likely view of the counterparty so they can negotiate price and terms that result in a division of the gains from trade advantageous to both parties.

MH policy considers these uncertainties as follows. First, a price based on the average of price forecasts purchased from multiple power price forecasting consultants is calculated. A premium is then added to this result. Second, the MH policy calls for the calculation of the avoided cost of the potential counterparties as a benchmark against the long-term price forecast. Pricing a contract using a counterparty's avoided cost is a well established pricing methodology in the utility industry. Developing these two price estimates provides an indication of the potential range of a contract's price.

4.6.1 Long-Term Contract Pricing

The following is a summary of MH's Pricing of Long-Term Export Contracts and how risk factors such as drought risk are addressed in the MH's pricing regime (*Source: Pricing of Long-Term Export Contracts, provided by Manitoba Hydro*).

- *"Long-term electricity price forecasts and market analyses are usually purchased annually from a group of industry consultants (for the 2008 forecast 5 expert consultants were used). The forecasts are adjusted to a common Canada-US border pricing point and are aggregated on a weighted basis following a detailed analysis and consideration of the fundamental assumptions that influence each of the electricity price forecasts.*

- *A* [redacted] *of approximately* [redacted] *is* [redacted] *to the 'on peak' price forecast for dependable energy to reflect the expectation that a* [redacted] *will be willing to* [redacted] *over the long-term. This* [redacted] *reflects MH's historical experience in selling a high value, long-term product backed from MH's dependable energy resources.* MH4

- *MH's Electricity Export Price Forecast is used among other things as a benchmark for the setting the minimum offer prices for long-term export sales. MH's actual offer prices may be higher reflecting the customer's alternative cost of supply and perceived demand for MH product. Final contract prices may reflect additional value provided to the customer or MH following negotiation, such as more favorable escalation terms, ownership of environmental attributes and an appropriate sharing of transmission costs.*

- *MH's long-term export product usually consists of surplus accredited capacity and surplus dependable energy delivered in the 16 peak hours of each day, Monday to Friday. Dependable energy is energy available even under a repeat of the lowest historic river flow conditions and may include energy sourced from hydro, wind, coal and gas fired turbines and from market purchases.*

- *Factors that create risk for MH are considered in the product offering. These factors include;*

  - *Price – Real price increases over the term of the contract are reflected in the forecast in order to capture the expected real growth in electricity prices due to factors such as the increasing cost of emission and carbon control.*

  - *Inflation – Inflation is adjusted for through an agreed to index such as US CPI or a natural gas price index. MH uses various indices to avoid the risk of over reliance on a single index.*

  - *Term – MH structures its portfolio of export contracts to have varied start dates and durations. This policy avoids the risk of having to renew them all at the same unfavorable time.*

  - *Foreign exchange rates – Contract prices are usually denominated in $US. The resulting contract revenue results in a hedge against the cost of the majority of MH's debt which is also in $US. MH manages an ongoing hedging program to manage the risk of unfavorable movements in foreign exchange.*

  - *Drought – Delivery obligations may be reduced during drought conditions and/or contracts may include return energy provisions to ensure there is always sufficient supply available to meet demand. In the Minnesota Power and Wisconsin Public Service sales currently being negotiated, MH will have sufficient surplus dependable hydro energy available from the construction of Keeyask and Conawapa to fulfill the contractual requirements, and is therefore not exposed to the cost of purchased energy or the cost of its own gas fired generation in order to serve the sales under historic low water conditions.*

  - *Curtailment and force majeure – During periods when delivery is not possible, due to severe drought (worse than historic), generation and transmission outages, etc., MH has the right to curtail in order to protect delivery to Manitoba customers and is not exposed to the cost of providing replacement energy.*

  - *Credit and Legal – MH is implementing industry best practices in determining appropriate contract provisions through the use of internal and external subject matter experts.*

- *Final contract terms and prices for long-term sales are subject to Corporate economic and financial analysis and review comparing the sale to a no-sale base case. The analyses include a simulation of all revenues and costs associated with and without the sale utilizing a repeat of historic river flows in each year over the term of the sale. This analysis and evaluation is done independently from the marketing and sales group responsible for the sale negotiation.*

- *All export sale contracts are approved in accordance with Corporate policy on the import and export of power. This policy specifies the necessary approvals; long-term sales require Board of Directors approval. In considering final approval, the Board is provided with the economic and financial analysis as well as all other relevant factors including a drought risk assessment."*

4.6.2 Long-Term Electricity Price Forecast

As evidenced in the above pricing regime, the long tem price forecast used by MH is an important input. The following is a summary of MH's Long-Term Pricing Forecasts Methodology (*Source: Summary of Long-Term Pricing Forecasts Methodology provided by Manitoba Hydro*):

- *"Long-term electricity price forecasts and market analyses are purchased from five industry experts. The industry forecasts have been used for 2007 and some consultants' forecasts have been consistently used since 2002, prior to the opening of MISO Day 2 in April 2005.*

- *The forecasts are assigned a weighting based on a detailed analysis and consideration of the fundamental assumptions that influence each of the electricity price forecasts. In 2008 it was an equal weighting.*

MH 4.

- *A [redacted] is [redacted] to the on peak forecast to reflect the expectation that a [redacted] would be willing to [redacted] over the long-term and reflect our experience to attain a higher value for a long-term dependable product sourced from dependable resources.*

- *The Electricity Export Price Forecast is used for the purposes of long-term studies and market activities related to:*

  - *the 2008/2009 Power Resource Plan which will result in generation cost and export;*

  - *revenue estimates for the 2008 Integrated Financial Forecast;*

- *the determination of marginal costs;*
- *the evaluation of export/merchant plant opportunities;*
- *the evaluation of resource options such as supply-side improvements and demand-side management; and*
- *establishing pricing targets for long-term dependable export sales.*

■ *The consultants price forecast reference is MINN Hub. The Corporation delivers its power to the Canada - US border the MHEB node. The Consultants price forecasts are deemed to reflect our experience for opportunity sales and purchases, adjusted to the Manitoba border. The adjustment to the Manitoba border is determined by considering the price difference or basis differential between the MINN Hub and MHEB node pricing points caused by transmission congestion and marginal transmission line losses, which is approximately 10% lower on-peak and 5.5% off-peak".*

The electricity price forecasts provided by the consultants provides both on-peak and off-peak market clearing prices. The on-peak market clearing price includes the value that reflects the short-run operating costs of the marginal unit to supply the next increment of energy to the grid during the on-peak period (energy value); and a value for short-term capacity adequacy that is driven by the need for reliable energy supply, which is intended to secure adequate reserve margins in the short-term (short-term capacity value). Therefore, the consultants' price forecasts are an all-in energy and capacity price.

4.6.3 Avoided Cost Analysis

In addition to examining forecasts of future market prices, we understand that MH also completes an avoided cost analysis to benchmark the long-term price against the long-run marginal cost of generation of the counterparties. This analysis is done using cost data on generation capacity, financing, variable O&M, emissions, and fuel from publically available sources.

Pricing a contract using counterparty's avoided cost is a well established pricing methodology. For example, in the US the 1978 Public Utilities Regulatory Policies Act (PURPA) required a utility to purchase power output from a qualifying facility (QF). Section 210 of the PURPA requires that the rates paid to QFs be *"just and reasonable"* and *"shall not discriminate against qualifying cogenerators."* However, the rates should not *"exceed the incremental cost to the electric utility of the alternative electric energy"* (*Source: The Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, sec. 210*). (i.e., the costs the utility avoided by purchasing from the QF).

A QF contract may have a fixed price term that lasts for many years or even decades. When a long-term QF contract's price is capped at a utility's unbiased projection of avoided cost, the QF purchase should *ex ante* not increase the utility's expected rates. As FERC observed in the preamble to its rules implementing PURPA (*Source: 45 Fed.Reg. 12224, February 25, 1980*), the QF price may turn out to be higher or lower than the utility's actual avoided cost. Nonetheless, an unbiased avoided cost projection is the commonly used benchmark by state regulators for capping the price of a long-term QF contract. Thus, QF pricing illustrates the important and relevant role of price benchmarking in ensuring that a utility's rates are *"just and reasonable"*, as required by Section 210 of PURPA.

While pricing a contract based on the counterparty's avoided cost is an accepted pricing methodology, the inputs to derive the avoided cost are equally important. MH's avoided cost analysis is generally in line with those of other jurisdictions. In general, PURPA delegates the responsibility for determining the utility's avoided cost and enforcement of the utility's purchase obligations to state regulators. Based on this authority, state regulators develop approaches to price benchmarking that while different across states in the details; nevertheless follow the same general principles.

For example the California Public Utilities Commission (CPUC) approach to price benchmarking uses publicly available cost data on generation capacity, financing, variable O&M, emissions, and fuel to calculate the long-run marginal cost (LRMC) of generation, the all-in per kWh cost of owning and operating new generation. In California, the California Energy Commission (CEC) publishes such cost data in its long-run market price projection. Such cost data and their implications are well-understood by the regulator and the regulated utilities because of their experience with avoided cost pricing and cost-effectiveness analyses in integrated resource planning. The resulting benchmark, being cost-based, is less vulnerable to the potential price distortions caused by electricity market imperfections. The CPUC has used this approach to determine the cap for the formerly integrated utilities' long-run avoided cost for QF pricing under Section 210 of PURPA and to perform cost-effectiveness evaluations of resources (*Source: California Public Utilities Commission and California Energy Commission, standard practice manual, 1987*). The CEC has also used it to project the long-run price in California for guiding the state's resource planning (*Source: California Energy Commission, Docket # 01-EOR-1, 2002-2012 Electricity Outlook Report, 2002*).

In summary, an avoided cost analysis is a useful addition to market price forecasts in the contract pricing process..

4.6.4 Escalation Factors in Long-Term Contracts

Another aspect of setting a long-term contract price is the price escalation factor, if any, used over the term of the contract. If the contract is appropriately priced at the expected long-term nominal price of power, there is no obvious need for any escalators, but to price a contract at the long-term nominal price of power requires an estimate of expected inflation which is essentially extraneous to the process. The more common procedure, therefore, is to strike a bargain at the expected real long-run price of power and use an escalation clause to account for inflation. Some of MH's contracts are structured in this way, using the GDP implicit price deflator as a measure of inflation.

It would be inappropriate to use market prices for power as the escalator. First, doing so would simply transform a fixed price contract to a variable price contract and reintroduce all the problems that led one to reject a short-run contracting framework in the first place. Second, the starting market price would then have to be unrelated to long-run avoided costs, since those already include expected market price increases. We note that some of the contracts do have alternative indices which might bear some relationship to market prices in MISO, e.g., those contracts which are partially indexed to gas and electricity prices. Such an index might be necessary where the buyer needs some such protection. Where this is the case MH should adjust their offer to reflect this adjustment to the avoided cost risk.

Based on the foregoing analysis, we feel that MH has developed an appropriate methodology for arriving at the sales price in its long-term contracts.

4.6.4.1 Comments on the Application of MH's Methodology

We note the following observations with respect to MH's application of its long-term contracts pricing methodology:

MH 4.

- MH [redacted] to the consultants' electricity price forecasts to set a reference price for the negotiation of long-term export contracts. MH's management control plan calls for this [redacted] to be applied. MH indicated to us that this [redacted] reflects its experience on previous negotiations as to what is achievable in the market place. MH further indicated that conceptually the [redacted] represents the value associated with MH being viewed as both a reliable supplier and a supplier of green energy as well as the value associated with providing price certainty to the counterparty. KPMG was not provided supporting documentation on the value of this [redacted] KPMG recommends that MH should clarify the role of this [redacted] confirm the appropriate magnitude and document this analysis.

- KPMG was provided with an avoided cost analysis for the WPS and MP term sheets. When KPMG asked for additional details on the process and documentation supporting this analysis, we were provided with a spreadsheet containing a cost build-up. On further inquiry regarding the inputs and assumptions used in the calculations, we were informed that the source of the data was information received in the past when MH was considering a potential asset acquisition and we were given a copy of the costing information provided to MH by the asset owner. KPMG recommends that MH document the process and methodology to be followed for future avoided cost analyses.

- In addition to the spreadsheet underlying the avoided cost analysis, MH also provided KPMG with two spreadsheet models that were used to set the price for the WPS and MP term sheets, i.e., in the form of a "levelized"[11] price. The models are based on the forecast prices and do not appear to take into account the

[11] *To calculate the respective capacity and energy revenues to MH over the contract term, the model respectively applies the contract volumes against a fixed capacity charge and forecasted future electricity prices. The anticipated revenues are then levelized by calculating the present value of contract revenues divided by the present value of cumulative contract volumes, all discounted at MH's cost of borrowing.*

MH4

avoided cost analysis. Since avoided cost analysis is an industry standard practice in establishing pricing for negotiating term sheets, KPMG recommends that MH consider avoided cost analysis in such negotiations. However, MH personnel indicated to us that they view the forecast price [redacted] as a proxy of their counterparty's avoided cost. Further, MH has indicated to us that in the context of the WPS and MP term sheets, its personnel were confident that they understood where market prices were and specifically what prices would be acceptable to the counterparty. Accordingly MH is relying on the considerable industry experience of the key individuals involved. Again, as mentioned elsewhere, a reliance on a small number of highly skilled individuals is evident, together with the need to consider the risk associated with the potential loss of key personnel.

- Through our interviews with MH personnel, we understand that MH does not view the term sheets executed with WPS and MP as fully binding contractual commitments between the parties given the extent of the conditions precedent contained therein. Instead, MH views them as a step along the way to reaching such firm contracts.

  KPMG notes that contract term sheets were signed with counterparties with the caveat of *pending MH Board approval*. KPMG further notes that MH management presented the term sheets to the MH Board for information. In the context of WPS and MP term sheets, the minutes of relevant MH Board meeting indicate that the Board requested the following information to be provided before seeking approval to enter into binding commitments:

  – an updated financial analysis of the proposed long-term sales and associated generating and transmission facilities, comparing proceeding with and without the sales;

  – information on the magnitude of the developments, opportunities and risks of the proposed sales; and

  – other relevant information.

  MH management has indicated to KPMG that it intends to provide this information to the Board when the project has advanced sufficiently prior to seeking final Board approval.

  It is common practice for management to sign term sheets pending their Board approval for the sake of commercial expediency. However, in such circumstances, during the period prior to obtaining Board approval, any expenditure in developing a project is exposed to the risk that the Board may not approve the term sheet.

Perhaps more importantly for MH, it faces the same risk with the counterparty. To the extent this is not already occurring, KPMG recommends that MH regularly follow up with the counterpart to its signed term sheet to ensure that the counterparty is seeking the required governance approvals and consider the status of this in expending efforts to develop the project.

4.7 Sales Volume Commitments

In resource planning studies, MH examines how it might expand its system for the benefit of the ratepayers of the Province. MH has asserted that export sales have covered a significant portion of the carrying cost of the new facilities that were built to support them. The next question is how does MH decide how much power it can sell outside the Province on a firm[12] basis and is this decision sound?

MH has asserted that the firm volumes committed under its long-term export contracts (current and planned) are such that MH can meet current and projected Manitoba load and the Capacity and Energy Resource Planning Criteria described earlier from its current and projected dependable energy supply.

A key issue in evaluating the prudency of the export volumes committed under long-term contracts is therefore the calculation and definition of the amount of dependable energy supply. Concerns have been raised that MH's models used to calculate dependable energy/drought risk are flawed. Concerns[13] that have been raised with respect to the definition of dependable energy supply and its link to long-term contracting include the following:

[12] *Firm power sales are "guaranteed" and create some an obligation on the part of the seller. If the seller can't deliver the power, then the buyer may be entitled to damages in lieu of the power that the seller was obligated to deliver.*

[13] *For example, PUB order 32/09 states on page 27 (of 48) that "Dependable hydraulic generation for the year 2003/04 was 18,500 GWh, that being a level significantly below the 21,000 GWh on which MH bases its potential for firm export contracts (after fulfilling the domestic requirement). Yet, MH has not lowered the dependable resource level to 18,500 GWh; rather MH now defines the dependable resource as a multi-year historical event (not a one-year event). This effectively means that once every fifteen years (the deemed frequency of the 2003/04 drought event), MH will be faced with dependable energy shortfalls comparable to 2003/04; though perhaps in an environment of much higher import prices. MH has not adequately demonstrated that the Corporation's mean energy forecast adequately reflects this self-imposed additional risk."*

- Dependable energy supply includes the amount of energy that can be supplied under firm import contracts. These contracts, which provide import energy at market prices, leave MH exposed to high prices in MISO during drought years.

- Dependable energy supply includes energy supplied from MH's thermal facilities. These facilities are relatively inefficient and will thus only operate for any significant amount of time under drought conditions. Under such a scenario, MH will be exposed to the risk of high prices for input fuels.

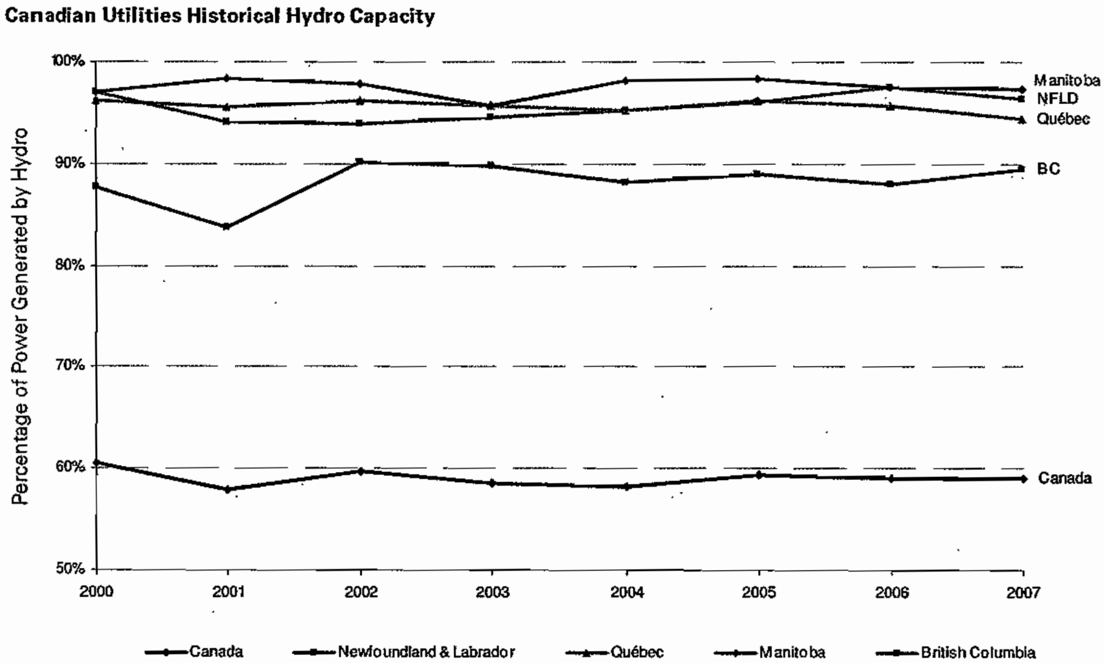
- Dependable energy supply is based on MH's historical flow record. Flows worse than the historical record could occur and these could jeopardize MH's ability to serve its full commitments.

4.7.1 Assessment of MH's Dependable Energy methodology

We have a number of observations with respect to these concerns that must be put in context of MH's unique circumstances, namely a very high proportion of electric production from hydroelectric sources and highly variable hydro capacity factor.

Among Canadian utilities, MH has the highest proportion of electric production from hydroelectric sources as shown in Exhibit 4-13.

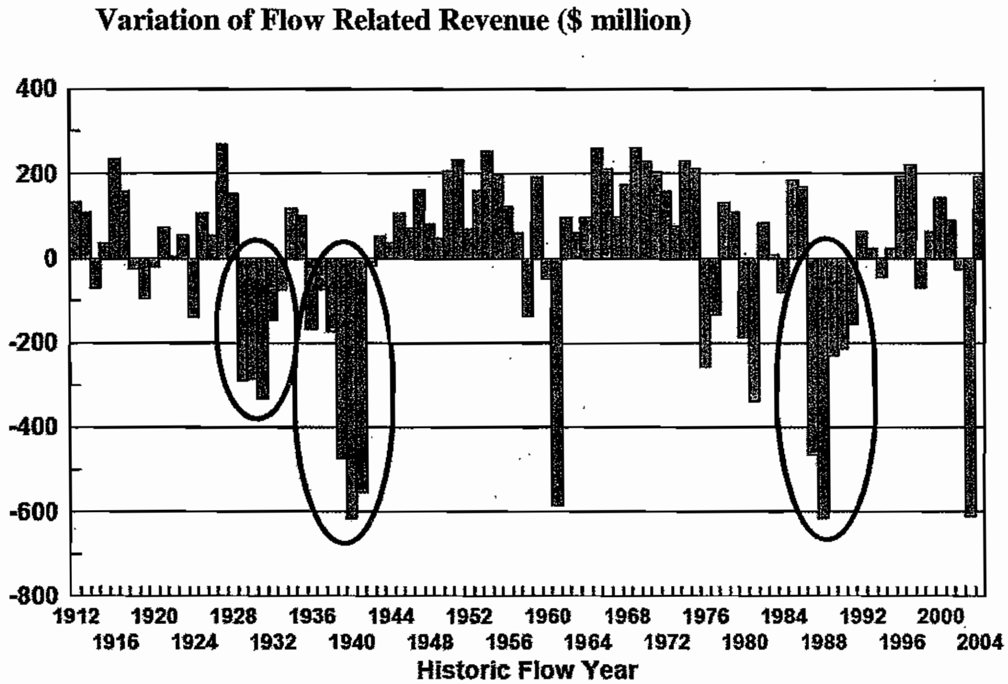
Exhibit 4-13: Hydro Capacity of Select Canadian Electric Utilities



Source: Statistics Canada, Electric Power Generation, Transmission and Distribution Reports

More so than other Canadian utilities, MH must therefore pay special attention to ensuring that it does not over commit firm energy; the production of which is highly dependent on uncertain water flows as illustrated in Exhibit 4-14.

Exhibit 4-14: Manitoba Hydro Variation of Flow Related Revenue



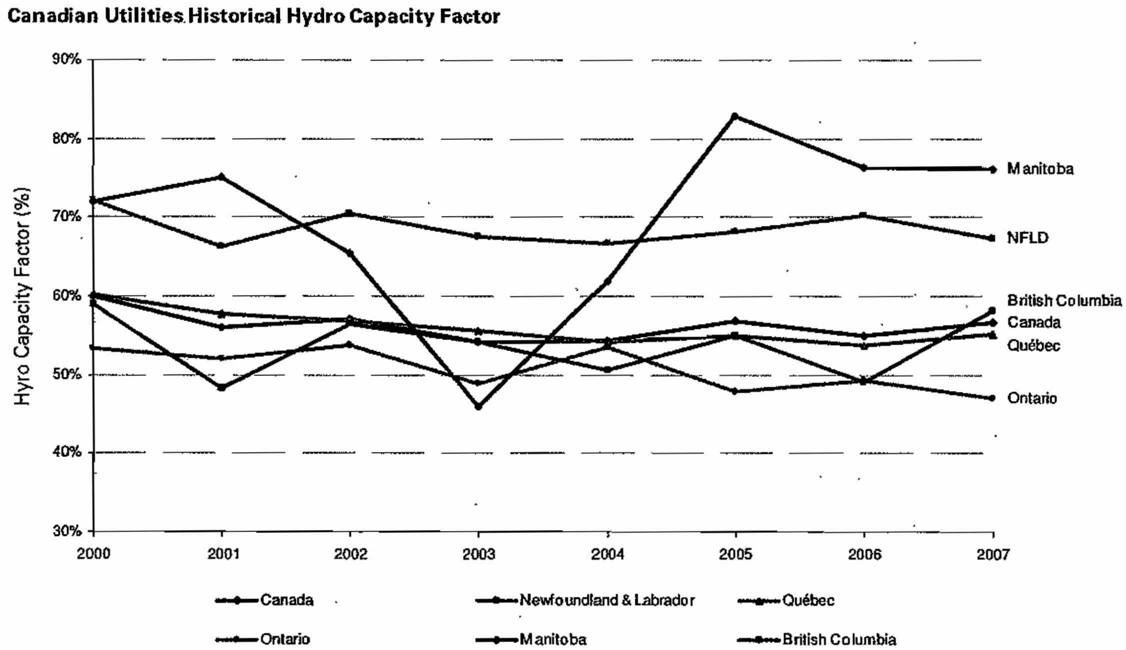
Notes:

1. The calculations for the graph above assume current generation capability and a single base case for other parameters.
2. The circled time periods indicate extended drought years.
3. The years 1937 to 1941 are the worst five years of drought in MH's historical water record.

Source: Manitoba Hydro response to PUB Order 117/06, p.1.

Another way of looking at this variability is an examination of MH's historical capacity factor compared to other major Canadian utilities. As indicated in Exhibit 4-15, MH hydrology is much more variable than its Canadian peers and is further an indication of the limited storage capacity in MH's hydro system.

Exhibit 4-15: Hydro Capacity Factor of Select Canadian Electric Utilities



Source: Statistics Canada, Electric Power Generation, Transmission and Distribution Reports

If MH was to exclude firm import contracts as a source of its dependable energy, then it would either:

- have to build additional domestic thermal generation; or
- reduce the amount of power that is sold on a firm basis. The amount of power thus freed up from long-term contract commitments would instead need to be sold on a short-term, or spot basis, leading MH to be exposed to spot market price fluctuations in years when such surplus energy is available.

By purchasing firm import contracts, MH effectively "outsources" some of its back-up requirements to external parties. A key advantage of this approach is that the thermal generation thus obtained has more opportunity to be used for purposes other than providing back-up to MH. This reflects a location that is nearer to major US markets, and less subject to import transmission constraints, and which can better take advantage of diversity in demand profiles. (US utilities tend to be summer peaking while MH is a winter peaking utility.). As a consequence, MH is likely to pay lower costs for such back-up generation by outsourcing it than by building thermal generation locally.

To help quantify potential financial risks to MH of the proposed new export contracts, we asked MH for an analysis of the additional costs to MH of a drought scenario as a result of entering into the long-term contracts in parallel with building associated new generation facilities. This analysis is summarized later in this chapter.

Adopting a stricter definition of dependable energy would undoubtedly reduce the risks that MH faces under scenarios of very low flow. In this context, risks could be in the form of financial losses that result under such a low flow scenario. Such a reduction in the risk of loss, however, has to be balanced against decreases in expected returns under the full range of flow conditions.

For Keeyask, which is the proposed new generating plant that is associated with the WPS and MP contracts, average annual energy is 4,430 GWH and dependable energy is 2,900 GWh. Thus, on average, the difference of 1,530 GWh, or roughly one-third of the total average expected energy from this facility, will be delivered to spot markets or otherwise sold on a short-term basis (*Source: Manitoba Hydro Report, "Major Facilities Strategy, A Power Supply Perspective", Table 3, October 2009, p.18*). A stricter definition of dependable energy would inevitably result in more of this energy being delivered to the spot markets and hence subject to significant price uncertainty and revenue volatility. As has been explained previously, low revenue volatility is a benefit to MH and Manitoba ratepayers.

With regards to the calculation of dependable energy, MH performs this analysis using SPLASH. The SPLASH model is discussed in more detail in Chapter 3.

With regards to the concern that the calibration of dependable production to the drought year of 1940-1941 is inadequate, we note that this concern can be interpreted in different ways:

- An interpretation is that a drought of 1940-1941 intensity would in fact lead to shortages. This assumes that SPLASH does not do what it purports to do. As noted previously, we find that as used, SPLASH is an appropriate decision support tool.

- Another interpretation is that droughts at a 1940-1941 level do not in fact represent a once-in-94 year possibility but in fact are more likely than that. This is of course possible, and as we understand it, MH has embarked on a series of studies to help better understand the probabilities of drought of a given level.

Based on the information presented above, we see no evidence that MH is over committing its firm dependable energy production through the proposed export contracts is and thereby unnecessarily exposing MH to volume risk.

4.8 Contract Structure

While long-term contracts for firm energy sales are a sound method for mitigating risks associated with the construction of new facilities, the form that the contract takes matters. The original long-term contracts which had been employed by MH had limited curtailment rights, while the new form of contracts have more curtailment provisions. While such provisions clearly reduce risk for MH, they do so by either making the contract riskier for the counterparty or changing the nature of the product (i.e., purchasing energy without firm capacity). Without knowing how counterparties value MH's curtailment rights, it is difficult to know whether such provisions are cost-effective or not.

This proposition is generally applicable to almost all novel terms. The aggregate risk of long-term contracts must be allocated between the parties. The general theory of risk bearing makes the commonplace observation that those best able to bear the risk – either because they have a relatively higher tolerance for risk, a better ability to manage risk, or because they have better ways to assess the risk – ought to bear the risk.

MH's counterparties are at a significant disadvantage in assessing hydrologic risk. MH knows a great deal more about the hydrologic conditions in its system than other market participants do. It is possible that MH and the Province might wish to limit their risk in the firm power sales contracts. The implication, however, is that the prices MH will receive are less than they would be if MH self-insured against such risks. Curtailment rights diminish the value of power to MH's counterparties, and can significantly weaken the counterparty's interest in closing a deal. Finally, curtailment rights can lead to significant litigation – was the contract curtailed because of the actual rights in the contract, or because the market worth of power was greater than the contract price?

The form of the contract must also be consistent with the needs of the counterparties. We are not in a position to state the intent of the counterparties. However, if the buyer is seeking a long-term resource to serve anticipated load obligations and the seller is seeking to sell surplus sales and finance a new generation project, then the contract form needs to match these objectives.

We note that in the electric utility industry, fixed price contracts of the form entered into by MH are a relatively common structure. MH is entering into standard arrangements seeking mutually acceptable terms trending to greater curtailment provisions to mitigate volume risk and should continue to assess what the most appropriate form of contract should be for each arrangement.

4.9 Manitoba Hydro's Risk Mitigation Strategies for Power Sales

While we have discussed some ways in which MH mitigates the risks associated with its long-term firm export commitments in the previous sections, it is worthwhile to examine these in some further detail, especially the much greater mitigation of risks in the three proposed long-term contracts[14] relative to MH's existing long-term contracts.

With the envisioned risk mitigation terms in the proposed long-term contracts, the risks assumed by MH in selling long-term firm power appear reasonable in consideration of the firm sales commitments during droughts. This is based on the following contractual provisions in the term sheets for the proposed contracts:

- Curtailment rights in the [redacted] MH should a drought of severity within the historical record occur. In such a drought event, MH can decrease firm energy volumes in these contracts by MH [redacted] if necessary, to meet domestic load. This decrease results from the ability of MH to reduce sales volume [redacted] MH [redacted] MH 1. MH 4.

- Curtailment rights should a drought of severity outside of the historical record occur. MH has negotiated into its proposed contracts the right to curtail energy supply in the event of an extreme drought to the extent needed to serve high priority domestic load or in the event of catastrophic failure of its DC transmission system. Thus under these adverse conditions, MH can provide all its available supply to its high priority domestic load.

- Firm delivery volume reduction rights exist in the MH [redacted] if and when MH declares Adverse Water Conditions, i.e., drought. In this contract, MH can MH [redacted] that it will not be obligated to deliver to [redacted] MH. Thus MH can preserve the associated water in its reservoirs to produce electricity for Manitoba consumption. While MH [redacted] MH MH 1. MH ~~3~~, 1. MH 1,

[14] *Please refer to Appendix H for a summary of the term sheets for the proposed long-term contracts.*

MH 4. MH [redacted] The terms of this call option are discussed in more detailed in the section 4.9.1.

4.9.1 Comments on the Embedded Call Option

MH 1. The embedded call option associated with the MH [redacted] has the specific provisions noted below:

[redacted]

MH 1., 2., 3., 4.

[redacted]

[redacted]

[redacted] MH 1., 2.,

MH's rationale for this option is that since the MISO price would be expected to be set by a marginal unit with a heat rate[15] in the range of [redacted] consuming [redacted] priced off the chosen [redacted] the call option [redacted] serves as a price cap. In the above example, the MISO price is expected to be [redacted] if the marginal unit has a [redacted] Thus if [redacted] had to replace the curtailed power by buying from the MISO market, it would do so at an effective cost of [redacted] (i.e. less the [redacted]. The [redacted] can be seen as compensation to [redacted] for the [redacted] This is the attraction of the option to [redacted] As long as the MISO price is set by the chosen [redacted], and the MISO market average heat rate is [redacted] or less, [redacted] can be reasonably sure of never having to pay more than the contract price for replacement power.

MH 2. MH 1., 2. MH 2. MH 2., 1. MH 2. MH 2., 2., 1 MH 2. MH 4. MH 2., 1.

The benefit of this call option is that it provides MH a LD benefit to the extent that MH can avoid using its thermal units with a greater than [redacted] to generate the curtailed amount of power. This analysis assumes that the [redacted] cost to MH under a "self produce" scenario would be at the same or lower basis as the [redacted] index chosen to settle the call option. As an additional benefit, MH would not have to incur the [redacted] that it would have physically burned in its thermal units in the absence of this call option.

MH 4.

4.9.2 Comments on Volume Curtailment Provisions

Taking into account the various contract provisions noted above, [redacted] Volume curtailment is especially important if in the context of a drought, domestic demand growth turns out to be

MH 4.

[15] *Heat rate is usually expressed as the ratio of the amount of natural gas burned as typically measured in MMBtu's to produce a MWh of electricity. Thus an [redacted] MWh heat rate generation unit signifies that [redacted] of natural gas will be burnt in the generator to produce 1MWh of electricity.*

MH 2.

greater than forecast, or future drought plans are similar to the 2003 drought plan, which required MH to assume higher than forecast domestic demand. Though MH has curtailment rights, in our interviews with MH management, it was repeatedly stressed that MH has a history of very reliable supply and is viewed as a reliable source of power by counterparties. Thus, it has a business interest in avoiding use of this and the other mitigating options to its firm obligations. Even so, MH has [redacted]

4.9.3 Impact of Diversity Agreements

MH's "Diversity Agreements" are another aspect of its power sales risk mitigation strategy. As discussed earlier in this report, MH has significant surplus capacity in the summer season, when its energy requirements are low, but lower capacity in the winter season, when its energy requirements are high. To balance the seasonal capacity and energy requirements, MH has entered into a number of agreements to exchange capacity and associated energy between the counterparties that have power systems whose peak loads occur at different times in a year, i.e., Diversity Agreements.

Specifically, the Diversity Agreements provide for an exchange of capacity and energy between the Summer Season (May 1 to October 31) and the Winter Season (November 1 to April 30) at the option of the holder. The Diversity Agreements require the supplying system to reserve firm capacity to ensure the capacity and energy is available at the request of the counterparty. During each Summer Season or Winter Season, the supplying counterparty may, at its option, limit the energy associated with the Diversity Agreements to an amount which will result in an average capacity factor of 20% over that season.

MH has a total of 500 MW of Winter/Summer Season capacity exchange available under Diversity Agreements, a 150 MW and 200 MW Diversity Agreement with Northern States Power ("NSP"), and a 150 MW Diversity Agreement with Great River Energy ("GRE"). The Diversity Agreements provide that each party has the right to limit the amount of energy delivered over that season to an average capacity factor of 20%. The Diversity Agreements also provide for certain energy guarantees which enable access to additional capacity in the event that MH is experiencing adverse water conditions. The maximum energy provided by the energy guarantees contained in the Diversity Agreements is 2,120 GWh over a twelve month period. The total energy available under the Diversity Agreements, including the energy guarantees, are considered firm energy, and as such are included in the determination of MH's dependable energy.

The Summer Season energy price received by MH under the 150MW and 200MW
Diversity Agreements with NSP are [redacted] MH for the Summer MH 4.
Season [redacted] MH thereafter by the [redacted] MH MH 2., 4.
[redacted] MH The Winter Season energy price paid by MH to NSP is MH 4.
based on the [redacted] MH The Summer/Winter MH 2.
Season [redacted] MH in the NSP Diversity Agreements are [redacted] MH; however, MH 2.
it should be noted that the two NSP Diversity Agreements were amended in 2002 to
[redacted] MH the Winnipeg-Twin Cities 500kV Interconnection MH 2.
Coordinating Agreement with NSP for the purpose of allowing MH to conduct power
and energy transactions. For the 2009 Summer Season, the [redacted] MH under the MH. 2
150 MW GRE Diversity Agreement has been [redacted] MH For the Winter
Season, MH has the [redacted] MH and [redacted] MH any
[redacted] MH available at the [redacted] MH There is no capacity
price under the Diversity Agreements.

In addition to the Diversity Agreements outlined above, MH has also entered into a
long-term Energy Service Agreement with NSP to provide firm import capabilities
for up to 500 MW during the period [redacted] MH and preserves
MH's right to utilize the firm northbound Winnipeg-Twin Cities 500kV
Interconnection transmission service. This Energy Service Agreement will [redacted] MH
the existing 150 MW NSP Diversity Agreement beyond [redacted] MH The [redacted] MH MH 2.
[redacted] MH during any time of the year and MH is obligated
to [redacted] MH provided the transmission
capability is 500 MW.

The capacity/energy obligations associated with the four contracts are summarized in Exhibit 4-16.

Exhibit 4-16: Diversity Agreement Capacity/Energy Obligations

MH 2.

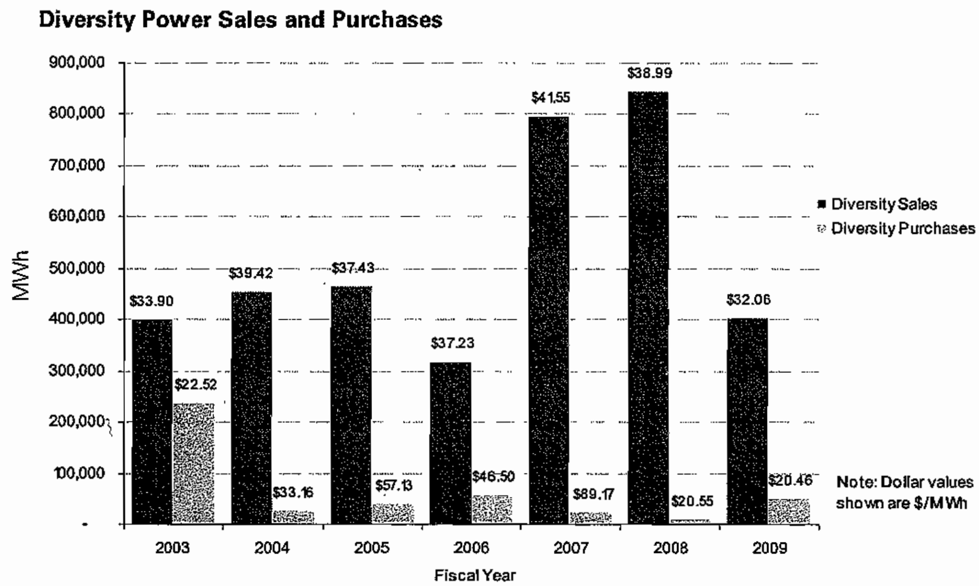
Customer	MW	Annual Dependable Energy, GWh	Type	Term
NSP	200	[redacted] MH	Diversity Exchange 20% capacity factor	Nov 1996 - Oct 2016
		[redacted] MH	Diversity Exchange Energy Guarantee	
NSP	150	[redacted] MH	Diversity Exchange 20% capacity factor	May 1995 – Apr 2015
		[redacted] MH	Diversity Exchange Energy Guarantee	
GRE	150	[redacted] MH	Diversity Exchange 20% capacity factor	May 1995 – Apr 2015
		[redacted] MH	Diversity Exchange Energy Guarantee	
NSP	500	[redacted] MH	Energy Service Agreement - minimum energy	May 2009 – Apr 2019

Source: Manitoba Hydro 2009/10 Power Resource Plan, Table 3

As indicated above, the Diversity and Energy Service Agreements provide MH with up to 2,656 GWh's of annual dependable energy import capabilities and preserves the firm northbound Winnipeg-Twin Cities 500kV Interconnection transmission service for MH to conduct power and energy transactions.

Based on the our review of the period May 1, 2003 to December 31, 2009, in Exhibit 4-17 we have summarized MH's utilization of the Diversity Agreements for Diversity Sales of Summer Season capacity at average energy prices received, and Diversity Purchases of Winter Season capacity at average energy prices paid.

Exhibit 4-17: Diversity Agreement Power Sales and Purchases (US$)



Source: KPMG analysis of historical purchases and sales

As indicated in Exhibit 4-17, the Diversity Agreements provide MH with firm energy sales in the Summer Season when MH has surplus capacity. MH only relies on the Diversity Agreements for firm import capacity in the Winter Season when MH capacity is constrained due to low water flows, or if the seasonal on-peak/off-peak price differential is favourable to MH. In this context, it is worth noting that historically, MISO summer season on-peak energy prices have been greater than the winter season on-peak energy prices. Thus MH has sold more power in the summer and at a higher price than it has bought back in the winter.

4.10 Drought Risk Analysis of MH's Preferred Development Sequence

MH has to meet Manitoba load demands and its contractual firm obligations under the long-term contracts from a hydrological system that has variable water flows. Even with the various aspects of MH's practices that mitigate this risk, there is still some risk due to that the water flow volumes will not be sufficient to meet MH's obligations in periods of adverse water conditions, i.e., a drought.

As noted earlier, MH is subject to unusually wide variation in water flows relative to other major hydroelectric utilities. From a financial planning perspective, MH's ability to withstand a drought is thus a major concern. As a result, the potential financial impact of drought events has been the focus of a variety of MH reports and submissions to the PUB.

In examining drought risk, MH has typically focused on the financial impact of a drought beginning in the next fiscal period and extending over a five or seven year period. Financial impacts are measured relative to the base financial forecast contained in the IFF. Droughts impacts are measured at expected prices and, in some cases, have also been examined under a scenario with high external electricity prices and high natural gas prices. MH's reports to the PUB have typically focused on the following metrics:

- changes in Revenue relative to the IFF by year;
- changes in Net Income by year;
- changes in Debt Ratio;
- changes in Interest Coverage Ratio; and
- the cumulative change in Retained Earnings over the drought period.

The cumulative change in Retained Earnings over the period of the drought is, in all cases, higher than the total change in Net Income. This reflects additional financing costs that are incurred over the period of analysis a result of reductions in cash flow.

The analyses assume that MH domestic rates remain unchanged, relative to the forecast in the IFF.

Exhibit 4-18 summarizes, at a high level, some key aspects of these analyses.

Exhibit 4-18: Financial Impact of Drought Events

($ billions)

Metric	5-Year Drought (2009 – 2013)	7-Year Drought (2009 – 2015)	
	Expected Prices	**Expected Prices**	**High Prices**
Total Reduction in Net Income	1.693	2.149	2.460
Cumulative Impact on Retained Earnings	2.764	Not Presented	3.515

Source: Manitoba Hydro response to PUB Order 117/06

As indicated in Exhibit 4-18, a five-year drought at expected prices results in a $2.764 billion reduction in Retained Earnings.

These analyses are not new, and have been the subject of significant deliberation at the PUB. Analyses of drought costs, in particular, have influenced the development of MH's financial targets for the ratio of debt to equity and for required Retained Earnings as a buffer or risk capital reserve for drought risk.

4.10.1 Assessment of Drought Risk on MH's Preferred Development Sequence

To assess MH's drought risk analysis on MH's preferred development sequence, KPMG asked MH to run various drought scenarios on their development plans in the 2009/10 Power Resource Plan (PRP). The 2009/10 PRP establishes that the preferred option (development sequence) to meet projected Manitoba load is to build both Keeyask (in 2018) and Conawapa (in 2022/23), and enter into new export contracts with Wisconsin Public Service ("WPS") and Minnesota Power ("MP") that bring with them additional US transmission interconnection capabilities (herein defined as the "Sale Scenario").

To determine the preferred development sequence, we understand that MH compares the economics of various development sequences. Analysis is done by examining differences in the net present value (NPV) to MH ratepayers under the different sequences.

An example of an alternative development sequence in MH's 2009/10 PRP is one that excludes the export sales related to the WPS and MP contracts, and thus the planned new US transmission interconnections. This alternative development sequence requires Conawapa to be advanced by a year to 2021/22 and includes a combined cycle combustion turbine in 2033/34. The construction of Keeyask is no longer required in this sequence. We herein define this alternative development sequence as the "No Sale Scenario".

MH determined that the NPV of a Sale Scenario development plan was $5.018 billion (2009 $). The NPV of the Sale Scenario is [redacted] (2009 $) greater than the NPV of the No Sale Scenario (*Source: Manitoba Hydro 2009/10 Power Resource Plan, September 16, 2009, p.29*). Accordingly, the Sale Scenario development plan represented the most economic alternative development sequence and provided an expected internal rate of return of [redacted] (*Source: Manitoba Hydro 2009/10 Power Resource Plan, September 16, 2009, p.29*). In this section, we analyze the results of the various drought scenarios we had requested to address the question:

- Does the Sale Scenario (which includes the new export contracts and additional generation and transmission investments) still provide a positive value over the No Sale Scenario to MH, even in the event that a drought event occurs sometime during the period of the sale?

This analysis thus addresses the concern that long-term contracts could be uneconomic under certain scenarios, even if they do not result in undue risk of financial stress.

The quantification of drought risk is represented by the change in the financial position of MH in comparison to a "Base Forecast". The appropriate Base Forecast is the 20-Year Financial Outlook that is an extension to the Integrated Financial Forecast IFF09-01. The 20-Year Financial Outlook was approved by the Manitoba Hydro Board in January 2010. The 20-Year Financial Outlook reflects the Sale Scenario assumptions and takes into account 94 years of historic flow conditions in identifying expected financial results. The Financial Outlook also takes into account expected export and natural gas prices determined by Manitoba Hydro's 2008 Electricity Export Price Forecast for the 2009 to 2040 period ("2008 Price Forecast").

The drought risk analysis is conducted using the SPLASH computer model for low, expected and high export and natural gas prices (as determined by Manitoba Hydro's 2008 Price Forecast), based on the following assumed water flows for the various years of the development sequence as follows.

4.10.2 Low Flow Scenarios

To test the sensitivities of the NPV economic evaluation under varying water flow conditions, we asked MH to replace the assumed 94 year average historic flow conditions with low water flow conditions commencing at various times as follows:

- 5 year drought flow conditions of 1937 to 1941, commencing in 2011, 2013, 2019 and 2025, and returning to average 94 flow conditions in the periods preceding and following the low flow period assuming low, expected and high prices.
- 10 year low flow conditions of 1932 to 1941, commencing in 2011, 2013, 2019 and 2025, returning to average 94 flow conditions in the periods preceding and following the low flow period assuming low, expected, and high prices.
- 15 year low flow conditions of 1927 to 1941, commencing in 2011, 2013, 2019 and 2025, and returning to average 94 flow conditions in the periods preceding and following the low flow period assuming low, expected, and high prices.

The low water flow conditions were imposed on the Sale Scenario and No Sale Scenario to determine the impact on the NPV economic evaluation, assuming the cost of the development plans remained constant, but the water flow related benefits were impacted by flow conditions. The flow related benefits include opportunity export sales, cost of energy imports, cost of fuel and operations for thermal generation, and savings related to water rentals.

Exhibit 4-19 summarizes the findings of the low flow water scenarios compared to the NPV of [redacted] (2009 $) determined by MH in the Sale Scenario and No Sale Scenario provided in the 2009/10 PRP assuming low, expected and high export and natural gas prices.

Exhibit 4-19: Low Flow Scenario Analysis - Incremental NPV of Sale Scenario vs. No Sale Scenario

NPV of Low Flow Conditions Commencing at Various Periods ($ millions)			
	5-Year Period Water Flow Years 1937-1941		
	Low	Expected	High
Commencing in 2011 Commencing in 2013 Commencing in 2019 Commencing in 2025	[redacted]	[redacted]	[redacted]
	10-Year Period Water Flow Years 1932-1941		
	Low	Expected	High
Commencing in 2011 Commencing in 2013 Commencing in 2019 Commencing in 2025	[redacted]	[redacted]	[redacted]
	15-Year Period Water Flow Years 1927-1941		
	Low	Expected	High
Commencing in 2011 Commencing in 2013 Commencing in 2019 Commencing in 2025	[redacted]	[redacted]	[redacted]

Source: derived from Manitoba Hydro data and model runs

As indicated, the expected NPV's range from a low of [redacted] (2009$ million) in the fifteen year high price scenario beginning in 2013, to high of [redacted] (2009$ million) in the ten year high price scenario beginning in 2011.

Under all of the scenarios analyzed, the NPV of the Sale Scenario remains strongly positive relative to the No Sale Scenario. This means that drought events do not impair the economics of MH's preferred development sequence and associated proposed long-term contracts.

The above result is not unexpected. The new generating facilities and transmission assets associated with the contracts are long-lived assets that will generate positive returns for many years into the future. A drought, even one starting at the beginning of a hydroelectric plant's life, will likely not offset the long-run benefits of the additional generating capacity.

The MH analyses were pessimistic in one key aspect. For a particular drought run, financial results were calculated using low flows in the period of the drought. For all other years, financial results were calculated as the average of those obtained from each of the water flow sequences used within SPLASH. The water flows used to calculate results in other years thus contain the low-flow sequence used in the drought period. This results in slight negative bias in water flow assumptions because the low-flow sequence is over-represented. (It is used alone for the drought period, and then contributes to the results in all remaining years.)

4.10.3 High Flow Scenarios

We also asked MH to replace the assumed 94 year average historic flow conditions with high water flow conditions commencing at various times as follows:

- 5 year high flow conditions of 1966 to 1970, commencing in 2011, 2013, 2019 and 2025, and returning to average 94 flow conditions in the periods preceding and following the high flow period assuming low, expected, and high prices;
- 10 year low flow conditions of 1965 to 1974, commencing in 2011, 2013, 2019 and 2025, and returning to average 94 flow conditions in the periods preceding and following the high flow period assuming low, expected, and high prices; and
- 15 year low flow conditions of 1961 to 1975, commencing in 2011, 2013, 2019 and 2025, and returning to average 94 flow conditions in the periods preceding and following the high flow period assuming low, expected, and high prices.

Exhibit 4-20 below summarizes the findings of the high flow conditions compared to the NPV of [redacted] (2009 $) determined by MH in the Sale Scenario and No Sale Scenario plan provided in the 2009/10 PRP assuming low, expected and high export and natural gas prices.

As indicated, the expected NPV's range from a low of [redacted] (2009$ million) in the fifteen year low price scenario beginning in 2025, to a high of [redacted] (2009$ million) in the fifteen year high price scenario beginning in 2025.

Exhibit 4-20: High Flow Scenario Analysis - Incremental NPV of Sale Scenario vs. No Sale Scenario

NPV of High Flow Conditions Commencing at Various Periods ($ millions)			
	5-Year Period Water Flow Years 1966-1970		
	Low	Expected	High
Commencing in 2011	[redacted]	[redacted]	[redacted]
Commencing in 2013	[redacted]	[redacted]	[redacted]
Commencing in 2019	[redacted]	[redacted]	[redacted]
Commencing in 2025	[redacted]	[redacted]	[redacted]
	10-Year Period Water Flow Years 1965-1974		
	Low	Expected	High
Commencing in 2011	[redacted]	[redacted]	[redacted]
Commencing in 2013	[redacted]	[redacted]	[redacted]
Commencing in 2019	[redacted]	[redacted]	[redacted]
Commencing in 2025	[redacted]	[redacted]	[redacted]
	15-Year Period Water Flow Years 1961-1975		
	Low	Expected	High
Commencing in 2011	[redacted]	[redacted]	[redacted]
Commencing in 2013	[redacted]	[redacted]	[redacted]
Commencing in 2019	[redacted]	[redacted]	[redacted]
Commencing in 2025	[redacted]	[redacted]	[redacted]

Source: derived from Manitoba Hydro data and model runs

Under all of the scenarios analyzed, the NPV of the Sale Scenario remains strongly positive relative to the No Sale Scenario. This result is not unexpected and illustrates the financial upside to MH from high water flows in its preferred development sequence.

In conclusion, based on the above analysis, the Sale Scenario, which includes Keeyask, Conawapa, new US transmission interconnection capabilities and the WPS and MP export contracts, provides the most economic benefit compared to the No Sale Scenario plan, both in low flow and high flow years.

4.10.4 Impact of Curtailment Rights

As more fully described in section 4.9, the term sheets for the proposed long-term contracts provide that Manitoba Hydro can rely on certain curtailment provisions to lessen the amount of energy that Manitoba Hydro is contractually obligated to deliver during droughts of severity outside of the historical record. The potential impact of these curtailment provisions have not been included in the above analysis since these curtailment provisions apply in situations where MH is experiencing water flows worse than the 1937 to 1941 drought on historical record. The drought and low flow analysis included above does not assume flows lower than the 1937 to 1941 flows, therefore the curtailment provisions have not been factored into the analysis.

4.11 Quantification of Drought Risk and Associated Risk Capital Reserves

The prior section examined the potential impact that drought events could have on the economic evaluation of the proposed long-term contracts and on the associated development sequence.

In this section, we examine the potential impact of the proposed long-term export sales on the drought risk of MH, examined from the perspective of impacts on Net Income and Retained Earnings (and hence the associated risk capital reserves held by MH in the form of equity).

In order to isolate the impact of the long-term contracts on MH's drought risk, we requested MH to run drought risk analyses, similar to those described for the Sale Scenario in section 4.10, for the No Sale Scenario. This drought risk analysis is also conducted using the SPLASH computer model for low, expected and high export and natural gas prices (as determined by Manitoba Hydro's 2008 Price Forecast), based on the following assumed water flows for the various years of the development sequence as follows:

- Drought years – a reoccurrence of the worst five years of drought on record, commencing in:
  - **Year 2013** – corresponding to the start of the major construction expenditures for Keeyask.
  - **Year 2019** – corresponding to the in-service date for Keeyask and the start of the construction stage for Conawapa.

- **Year 2025** – corresponding to the in-service date of Conawapa.

  The start dates listed above were selected for the analysis because they represent potential points of financial stress when significant capital expenditures have been incurred by MH without the benefit of the corresponding revenues.

- Other years – for years not specifically identified with a drought under a particular scenario, the financial results reflect average or expected results taking into account the full 94 year historical flow record. We noted that this calculation of average results incorporates the impact of the five worst flow years on record. The result is thus more conservative than if the worst five flow years were excluded from the average.

A comparison of the financial impacts of drought conditions under a Sale Scenario and a No Sale Scenario allows us to isolate the financial risks associated with the associated development investments of additional generation (Keeyask and Conawapa), new US transmission interconnection, and the related long-term export contracts with WPS and MP.

These analyses thus identify the magnitude of drought impacts, taking into account the additional size and scope of MH as a result of new generation facilities and the related long-term contracts.

4.11.1 Summary Results

As described above, KPMG asked MH to conduct drought risk analysis on the Sale Scenario and No Sale Scenarios. Exhibit 4-21 provides a high level summary of our results. Results are presented in terms of:

- the cumulative reduction in Net Income[16] relative to plan as a result of five year droughts starting at various points in time; and

- the amount of MH Retained Earnings under the two scenarios at the end of each of the five year droughts.

Exhibit 4-21 focuses, for any particular combination of drought event and Sale or No Sale Scenario, on the cumulative reduction in Net Income and impact on Retained Earnings. It thus focuses on drought risk, as measured by a shortfall in cumulative

---

- [16] *The cumulative reduction in Net Income excludes financing costs associated with increased borrowing that may result from the Net Income reduction.*

Net Income relative to plan and the amount of Retained Earnings available to MH at the end of the drought. It is important to note, however, that the Net Income in the absence of a drought, which is the basis for calculating the differences shown in the Exhibit, is not the same under the Sale and No Sale Scenarios. In general, Net Income and Retained Earnings will be higher under a Sale Scenario. In other words, the drought risk (in terms of reduction in Net Income) will be calculated for a higher base under the Sale Scenario. This has implications for MH's ability to withstand a drought. MH's Retained Earnings (i.e., equity) will be generally higher under a Sale Scenario than under a No Sale Scenario, improving its ability to use its equity as a buffer to cover a given shortfall in Net Income as a result of a drought.

Note that in this analysis, Retained Earnings are allowed to accumulate over time with no dividends paid out. Thus, Retained Earnings for the Base Case may be overstated in the event that dividends are required to be paid by MH.

Exhibit 4-21: Impact on Net Income and Retained Earnings over a 5-Year Drought

($ millions)

	Cumulative Reduction In Net Income			Retained Earnings (Deficit) End of Drought		
	Sale Scenario	No Sale Scenario	Sale Scenario Greater Than (Less Than) No Sale Scenario	Sale Scenario	No Sale Scenario	Sale Scenario Greater Than No Sale Scenario
Drought Starting 2013						
- Low Price	2,089	[redacted]	[redacted]	1,031	[redacted]	[redacted]
- Expected Price	2,836	[redacted]	[redacted]	190	[redacted]	[redacted]
- High Prices	3,956	[redacted]	[redacted]	(1,079)	[redacted]	[redacted]
Drought Starting 2019						
- Low Price	2,626	[redacted]	[redacted]	2,973	[redacted]	[redacted]
- Expected Price	3,752	[redacted]	[redacted]	1,708	[redacted]	[redacted]
- High Prices	5,316	[redacted]	[redacted]	(53)	[redacted]	[redacted]
Drought Starting 2025						
- Low Price	3,502	[redacted]	[redacted]	8,494	[redacted]	[redacted]
- Expected Price	5,155	[redacted]	[redacted]	6,711	[redacted]	[redacted]
- High Prices	7,239	[redacted]	[redacted]	4,420	[redacted]	[redacted]

Source: derived from Manitoba Hydro data and model runs

As shown in Exhibit 4-21 above, for a drought commencing in 2013, the differences between the Sale Scenario and a No Sale Scenario, in terms of the impact on Net Income, are relatively small. It is reasonable that there is only a relatively nominal

Net Income difference between the Sale Scenario and a No Sale Scenario for five year droughts commencing 2013. This reflects the fact that the planned capital expenditures for the additional generation assets in the Sale Scenario only result in additional revenues after 2018, the in-service date of Keeyask. Hence, base or expected revenues under both the Sale Scenario and No Sale Scenario are relatively similar during the five year period beginning in 2013. As expected, the Net Income differential between the scenarios increases as the new generation assets are completed.

For droughts starting 2019 or later, Net Income is reduced to a greater extent in the Sale Scenario (but from a higher baseline) than in the No Sale Scenario for all price cases. However, an important finding illustrated in Exhibit 4-21 is that Retained Earnings fall to a lower amount in the No Sale Scenario as compared to the Sale Scenario for the drought scenarios analyzed. Stated differently, MH's Retained Earnings at the end of a drought are projected to be higher in the Sale Scenario than in the No Sale Scenario (hence the positive numbers in the last column of Exhibit 4-21).

Thus, the Sale Scenario provides MH with improved Retained Earnings compared to the No Sale Scenario. The improved Retained Earnings are due primarily to the increased surplus export sales associated with the new generation and increased US transmission interconnection capabilities. Moreover, the availability of increased US transmission interconnection capacity (planned in service date of 2018) under a Sale Scenario has an ameliorating effect on Net Income reduction due to droughts. This is due to the increased US transmission interconnection in the Sale Scenario allowing MH to import more power than in the No Sale Scenario with such imports being typically less expensive than MH's domestic thermal production.

Accordingly, the analysis of the Sale Scenario shows reduction of the overall risk of a five year drought compared to a No Sale Scenario, since it provides greater Retained Earnings to withstand the financial impact of a five year drought.

Summary

In summary, the Sale Scenario results in a relatively modest increase in the financial impact for drought events starting in 2013 and 2019. (The potential additional reduction in Net Income over a 5-year period, under expected prices, ranges from negative $10 million (i.e., a decrease in losses) to $95.8 million, as a result of moving to the Sale Scenario.) The additional cost of a drought under the Sale Scenario is greater for droughts beginning in 2025. Under the expected price case, a five year drought results in a cumulative reduction of Net Income of $617.3 million. Although drought impacts are larger in later periods in nominal dollars, they are relatively more manageable for MH because of its greater level of Retained Earnings by that period.

The results demonstrate that the Sale Scenario and the related long-term export contracts do not lead to a significant increase in financial risk for MH from a drought risk perspective. On the contrary, the Sale Scenario appears to reduce the overall risk of a five year drought compared to a No Sale Scenario, since it provides greater Retained Earnings to withstand the financial impact of a five year drought.

Further detailed runs on the above analysis appear in **Appendix J**.

4.12 Conclusion

With respect to long-term contracting for export power sales, based on our analysis combined with our knowledge and expertise in the energy sector, it is our opinion that:

- Manitoba Hydro has made appropriate strategic choices in entering into long-term fixed price contracts for export power sales;
- Manitoba Hydro has appropriately established the firm export volumes in these contracts; and
- Manitoba Hydro has an appropriate methodology for arriving at the sales price in such contracts.

  Also, we find that Manitoba Hydro continues to improve its contractual documentation to more effectively mitigate the risk exposure from entering into long-term fixed price contracts for the sale of firm energy. On the basis of the policy decisions in place with respect to risk tolerance, Manitoba Hydro quantifies its drought risk appropriately and currently provides for appropriate levels of reserves of risk capital against its projected drought risk.

5

5. Risk Governance

Risk governance addresses the roles, responsibilities, reporting relationships, and policies designed to support decisions about risk that may threaten an organization's achievement of objectives and the successful execution of its strategies. Risk governance has become increasingly important to power utilities for reasons such as the introduction of competitive markets, the recent turmoil experienced in financial markets and complex capital projects.

This chapter is organized under the following headings:

- 5.1 Scope of our Review
- 5.2 Key Findings
- 5.3 Approach and Methodology
- 5.4 Manitoba Hydro's Risk Governance Practices
- 5.5 Risk Governance Leading Practices
- 5.6 Case Studies
- 5.7 Risk Management Roles, Responsibilities and Reporting Relationships
- 5.8 Risk Management Policies
- 5.9 Conclusions.

5.1 Scope of Our Review

In Phase 1 of the Review, KPMG identified two issues within the Risk Governance Theme. The two Issues and along with a summary of the Consultant assertions of each Issue are outlined below.

- Issue 1 - Independence of the middle office function

The Consultant asserts that, as MH integrates risk management into its corporate framework, it is imperative to segregate the duties involved in calculating and reporting the risk and financial exposure of MH from the business units responsible for operating level decisions, trading and opportunistic deals. The Consultant asserts that segregation of these duties is an important internal control element of compliance programs because it mitigates errors and opportunities for corporate fraud and misstatement of financial earnings. The Consultant's assertion is that it is important for the middle office function to have an independent reporting relationship.

- Issue 2 - Resourcing and authorities relating to energy risk management

The Consultant asserts that the energy risk management function of MH does not meet best practices. Specifically, the Consultant notes that there are limited risk management policies with inadequate ability for the Middle Office to perform an oversight role over PS&O and trading transactions. The Consultant infers that relevant risk management reports are not being utilized in the management of risk at MH. The Consultant argues that it is common industry practice for risk management to monitor on a regular basis market price and hedging valuations in order to manage corporate performance in line with the achievement of the IFF.

Specifically, our assessment of risk governance considers the following elements:

- **Risk Management Roles, Responsibilities and Reporting Relationships** — focusing on risk management structure, committees, functional risk management duties, reporting relationships, resourcing, and delegated authorities with a primary focus on the Middle Office.

- **Risk Management Policies** – focusing on the risk management policy environment for power sales.

Our assessment relates to the MH power sales risk management function which may be divided into long-term sales (addressed to the extent of Issues raised in the previous and following chapters), and opportunity sales, which is the topic of this chapter.

For background purposes, we describe in this chapter the key elements of risk governance at MH. This establishes the broader context for our assessment of MH's risk management roles, responsibilities and reporting relationships, and its risk management polices with respect to opportunity sales.

The scope of our assessment does not include MH's corporate risk management function, operational risk management function (e.g., dam safety risk management procedures), its environmental risk management function, its major capital project risk management function, and its legal and regulatory risk management function.

MH's business model is built on a combination of domestic Manitoba sales, long-term contracts to export customers, and opportunity sales to extraprovincial / export customers. Opportunity sales are the responsibility of the Power Sales & Operations Division, with day-to-day oversight from the Middle Office.

In earlier chapters, we described MH's approach to power sales, insofar as it is asset backed. That is, the water resources needed to generate the power are known to exist with a high level of confidence prior to the actual sale of the energy. Opportunity sales do not characteristically present high levels of risk for MH, as they are made on a real-time basis, or day-ahead basis. Some volatility may exist on price, but the supply of, and demand for, the energy is known by MH staff with a high degree of certainty.

This contrasts with a speculative trading business model that trades energy and holds open positions, based on a market view. MH is not a trader of energy that takes speculative positions into the future. MH's primary business objective is to provide low cost and reliable energy services to its domestic customers and to optimize its assets and excess energy supply.

- We note that there are separate risk management functions to deal with long-term contracts which are largely outside the scope of this chapter. Long-term contracts are typically backed by new generation (e.g., Long Spruce, Limestone) and have characteristically been executed once every 10 to 20 years. There are significant risk management resources and processes dedicated to assessing these opportunities over a multi-year time frame. The large risks associated with these opportunities, including the economic models and load forecasts developed, are assessed, optimized and approved over a number of years by multiple layers of management at MH.

Decisions to proceed with new generation and long-term contracts are ultimately reviewed and approved by the Export Power Marketing Committee (EPRMC), the Executive Committee, the Audit Committee and Board of Directors. The risk management activities related to opportunity export power sales are transactional in nature – and within the purview of the Power Sales and Operations Division (PS&O). It is these transactions that the Middle Office is focused on monitoring to ensure that they are made in compliance with MH policies and procedures.

5.2 Key Findings

This section outlines our key findings with respect to risk governance.

With respect to the independence of MH's middle office functions, we find the following:

- The Export Power Middle Office (EPMO) is a single, independent, risk management function. It reports to the manager of Corporate Risk Management, who in turn reports to the Chief Financial Officer. It is independent from the Power Sales and Operations (PS&O) Division. It is steadily progressing in terms of its responsibilities for measuring, monitoring, controlling, and reporting the risks associated with PS&O's transacting activity. The progress made by the EPMO is consistent with the pace of change identified at other electric utilities in our case study research and continued progress is suggested.

- MH's risk power sales governance practices compare favourably for the most part to leading practices. Based on the nature of its asset backed power sales business model, the risk governance practices at MH are, for the most part, appropriate. The comparative analysis conducted by KPMG to other electric utilities demonstrates that MH's risk management practices are consistent with other utilities of similar size.

- Based on the size and nature of the asset backed power sales strategy adopted by MH, the independent reporting relationship of the Export Power Middle Office to Corporate Risk Management and the Chief Financial Officer is in keeping with leading practice.

- The power sales risk management policy framework substantially meets the leading practice.

- MH should continue to institutionalize the policy setting roles of the Export Power Middle Office and fully align its power sales risk management policies with leading practices for market, credit and contractual risk management. The current middle office structure partially meets the leading practices.

  In order to fully meet the leading practice, credit risk analysis should report directly to the Middle Office. The market risk quantification capabilities of the Middle Office should be enhanced. The HR and technology resources of the Export Power Middle Office to conduct independent risk assessments of power sales partially meets the leading practice.

MH should also continue its efforts to enhance the resources of the Middle Office through the addition of a market risk analyst. The credit risk analyst positions which currently report to the Contracts Administrator within the Export Power Marketing Group should report directly to the Middle Office. For operational efficiencies continued effective working relationships within the Export Power Marketing Group, these positions could continue to physically reside within PS&O.

MH should also continue to actively define its functional requirements (including risk metrics) and continue its efforts to acquire a risk analysis software tool to enhance the analytic capability of the Middle Office.

5.3 Approach and Methodology

Our approach to assessing risk governance related to opportunity sales at MH is based primarily on three lines of evidence:

- a review of MH risk governance practices to provide context for how opportunity sales risk management fits into the overall corporate risk management framework at MH, as described in section 5.4;
- a review of related risk management leading practices as expressed by a number of recognized authorities; and
- consideration of case studies of other electric power utilities in which we examined their risk governance roles, responsibilities and reporting relationships and their risk governance policies.

Our description of MH risk governance practices is based on data gathered from the following sources:

- documentation review; and
- interviews of MH personnel.

The documentation reviewed included organization charts, committee charters, terms of reference, committee meeting minutes, internal audit reports, and policies related to risk management. These documents were provided by MH and describe many aspects of its corporate approach to risk management for the period 2002 through to February 2010. Additionally, we reviewed third party reports that have been prepared for various purposes which document certain aspects of risk governance at MH.

We also conducted a series of interviews with MH personnel to validate our understanding of the documentation and to obtain an appreciation of how risk governance at MH functions in practice. Our interviews were conducted with personnel from the following areas: Corporate Risk Management, Power Sales and Operations Division, Finance, Corporate Controller, Legal, Export Power Middle Office, Power Planning and Development Division, Information Technology, and Internal Audit.

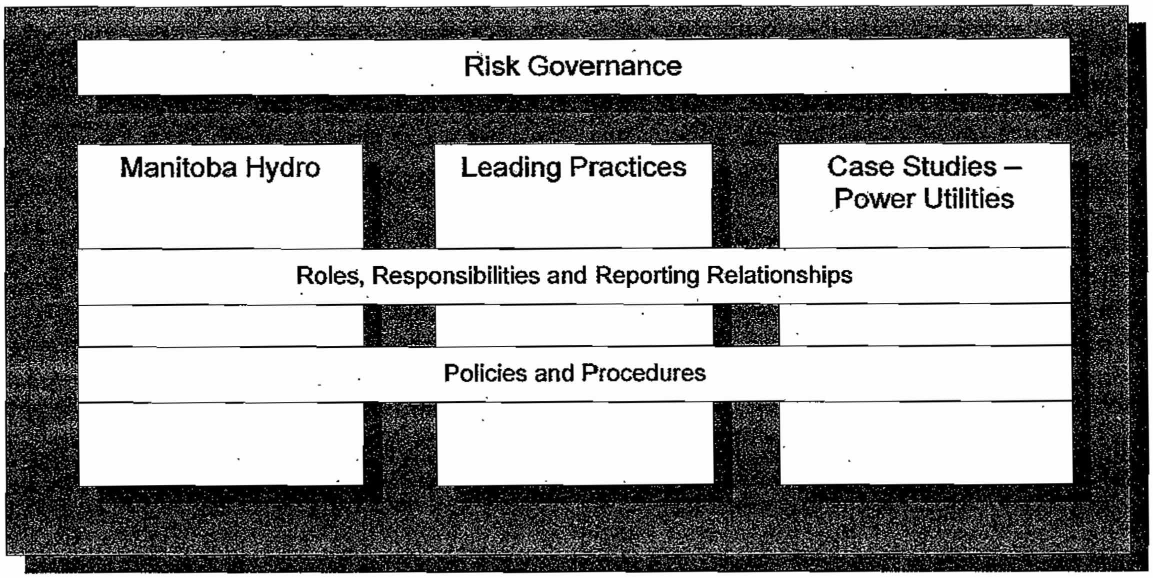
Our analysis compared MH's practices for opportunity sales to relevant leading practices in order to identify gaps and opportunities for improvement. Peer practices (i.e., case studies) provided additional insight on prevailing practices and underscored the aspirational rather than authoritative nature of leading practice literature. Utilizing both comparisons provides us with a principles-based perspective to the assessment.

Risk governance in practice is a balance between professional judgment exercised by experienced management and steady progress in adopting relevant aspects of risk management leading practice. We believe that this is particularly the case in the context of a power utility like MH because:

- there is no industry standard set of risk governance practices that apply universally to all power utilities; and
- each comparator utility considered in our case studies faces unique business circumstances and therefore is not directly comparable to MH.

Exhibit 5-1 provides a high-level summary of the approach and methodology described above by portraying the framework used for our review of MH's risk governance practices.

Exhibit 5-1: Approach



5.4 Manitoba Hydro's Risk Governance Practices

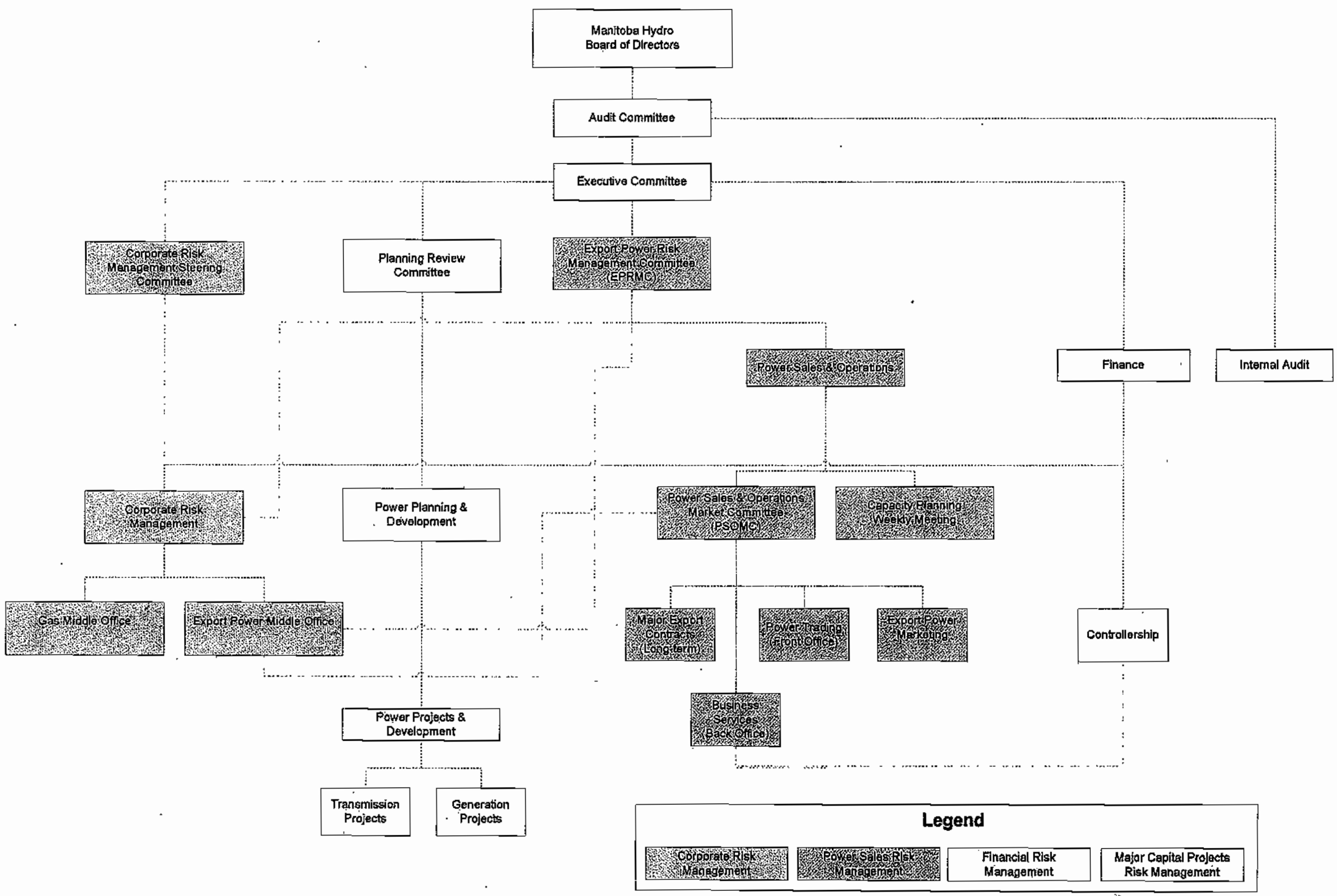
This section describes the risk governance practices at MH today. Its purpose is to illustrate the risk governance landscape at MH as context for our assessment of risk management over opportunity power sales, and the related role of the Middle Office.

MH has the following four key functional areas of risk management:

- Corporate risk management, which addresses strategic risk and coordinates the corporate risk profile.
- Power sales risk management, which addresses related market, credit and operational risk.
- Financial risk management, which addresses financial statement reporting and controllership risk; and
- Major capital projects risk management, which addresses planning, scheduling budgeting and quality risks associated with major generation and transmission construction projects.

Exhibit 5-2 presents an overview of this risk governance structure at MH focused on power sales.

Exhibit 5-2: Manitoba Hydro – Power Sales Risk Governance Structure



MH governs and manages risk through the following key risk management governing bodies and executive/management committees:

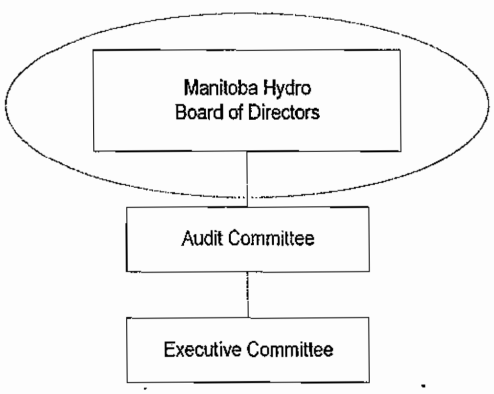
- Manitoba Hydro-Electric Board;
- Audit Committee;
- Executive Committee;
- Corporate Risk Management Steering Committee;
- Planning Review Committee;
- Export Power Risk Management Committee; and
- Power Sales and Operations Market Committee.

In Section 5.4.1, we describe each of these as well as MH's Export Power Middle Office.

5.4.1 Roles, Responsibilities and Reporting Relationships

This overview describes the roles and responsibilities of these risk management committees and their membership.

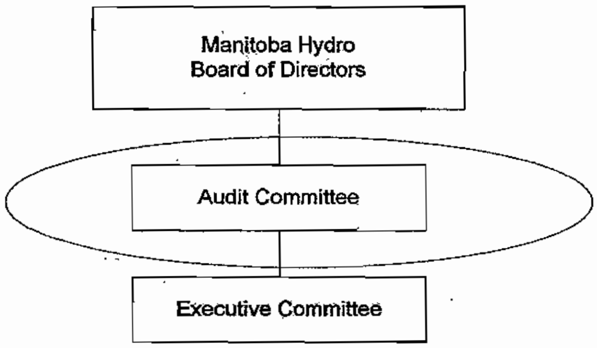
5.4.1.1 Manitoba Hydro-Electric Board



Oversight responsibility for corporate risk management rests with the Board of Directors. Primary responsibility for financial reporting, accounting systems and internal controls at MH is vested in senior management and is overseen by the Board of Directors.

The Board of Directors is ultimately accountable for ensuring, through management, that appropriate risk management policies, systems, governance, leadership and stewardship are in place. For example, regarding export and import of power, the Board of Directors oversees approval of any sales requiring new generation, in conjunction with approving new generation and long-term sales exceeding five years or 100 MW. The Board is comprised of not more than 11 members who are appointed by order of the Lieutenant Governor-in-Council. The Board meets eight times per year.

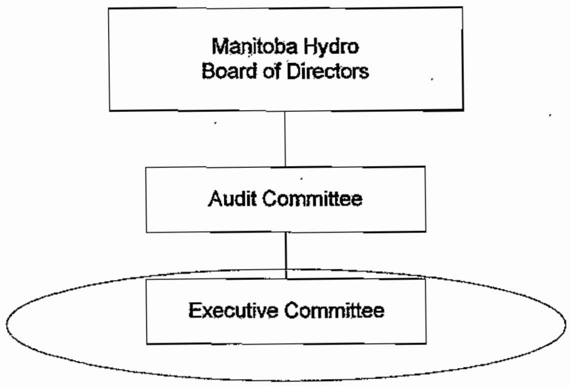
5.4.1.2 Audit Committee



The Audit Committee has been established by the Board of Directors to assist the Board in fulfilling its risk management responsibilities. The Audit Committee confirms that:

- MH complies with applicable laws, regulations, rules, policies and other requirements of governments and regulatory agencies related to financial reporting and disclosure;
- management has assessed areas of potential significant financial and operational risk to MH and has taken appropriate measures;
- MH's financial forecasts fairly represent the future financial direction of the Corporation and adequately support rate applications to the Public Utilities Board.
- MH's auditors have performed their duties satisfactorily and with sufficient independence from management;
- the accounting principles, significant judgments and disclosures that underlie or are incorporated in MH's financial statements are the most appropriate in the prevailing circumstances;
- MH's quarterly and annual financial statements present fairly Hydro's financial position and performance in accordance with generally accepted accounting principles;
- appropriate information concerning the financial position and performance of MH is disseminated to the public in a timely manner.

5.4.1.3 Executive Committee

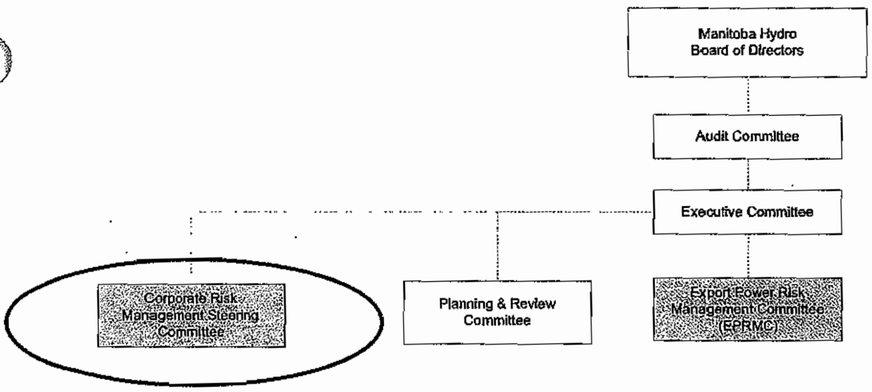


The Executive Committee acts in an advisory capacity to the President and Chief Executive Officer in addressing issues, initiatives or concerns of corporate significance. It determines or authorizes appropriate subsequent action to be taken to mitigate such issues and risks. Responsibilities of the Executive Committee include:

- assisting in the review and resolution of matters of corporate-wide concern;
- resolving matters of corporate policy;
- assisting in establishing a corporate position on external issues;
- reviewing items to be advanced to the Manitoba Hydro-Electric Board;
- acting as the Strategic Planning Committee;
- acting as the Review Committee for the Integrated Financial Forecast and the Corporate Risk Management Report; and
- approving all contracts for consulting services greater than $5,000 in value.

This Executive Committee is made up of the senior management team of MH and generally meets on a weekly basis.

5.4.1.4 Corporate Risk Management Steering Committee



The Corporate Risk Management Steering Committee was formed in September 2002. The Corporate Risk Management Steering Committee is to provide a cross-functional forum to guide and monitor the processes that ensure MH's principal risks are appropriately identified, assessed, managed and communicated. Its responsibilities include:

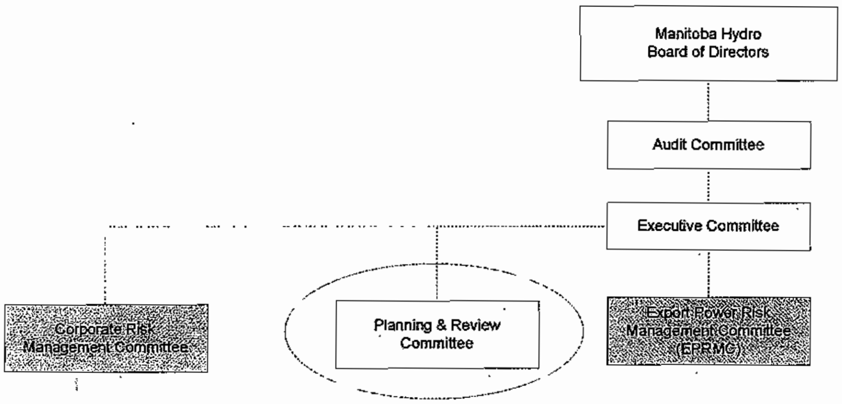
- introducing an organization-wide enterprise risk management framework and process to ensure that risks are identified, assessed, monitored, measured and communicated;
- recommending appropriate corporate risk policies and measures of risk tolerance;
- ensuring that there is an appropriate alignment between identified risks and corporate goals and strategies;
- creating a risk map or profile that identifies and assesses MH's key risks in terms of probability and magnitude of impact, and actions to be taken by the area responsible; and
- providing guidance for the development and maintenance of a risk monitoring and reporting system including the review and consolidation of periodic reports on specific risk areas from the business units and corporate functions.

All business units, at the division manager level, are represented on the Corporate Risk Management Steering Committee and it is chaired by the Senior Vice-President, Finance and Administration and Chief Financial Officer. The committee mandate is to meet six times per year. This is a comprehensive cross organizational committee and includes the following members:

- Senior Vice-President, Finance and Administration and CFO (Chair);
- Vice-President, Corporate Relations;
- General Counsel;

- Division Manager, Corporate Planning and Development;
- Manager, Insurance Services;
- Manager, Internal Audit;
- Division Manager, Business Analysis and Corporate Risk Management;
- Division Manager, Gas Supply;
- Division Manager, IT Services;
- Division Manager, Rates and Regulatory Affairs;
- Treasurer;
- Corporate Controller;
- Division Manager, Power Sales and Operations;
- Division Manager, Business Support Services;
- Division Manager, Consumer Marketing and Sales;
- Division Manager, Transmission System Operations;
- Division Manager, Apparatus Maintenance;
- Division Manager, Transmission Planning and Design;
- Manager, Corporate Planning;
- Manager, Corporate Risk Management; and
- Senior Risk Officer, Corporate Risk Management (Secretary of Committee).

5.4.1.5 Planning Review Committee

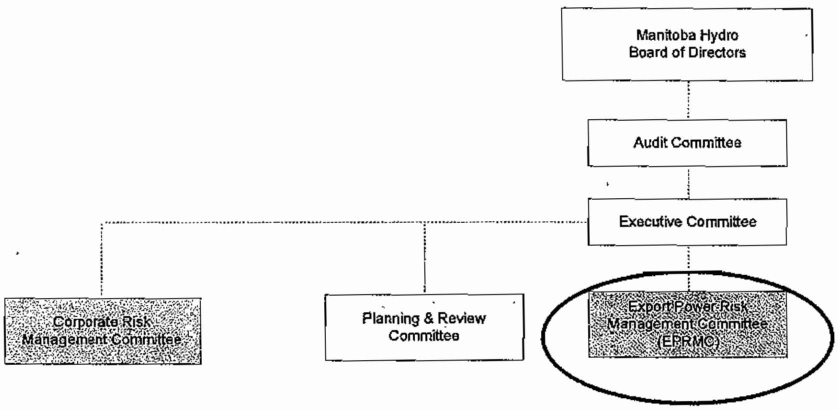


The Planning Review Committee reviews long-term planning issues with corporation-wide implications that are brought to it by the executive responsible for the issue. Some of the matters reviewed by the Planning and Review Committee include forecasts (e.g., economic outlook, interruptible import/export market, energy price outlook, system load forecast and avoided cost) and integrated resource plans (e.g., demand side management plans, supply side management plans, generation development plans, transmission development plans and import/export plans and contracts).

Members of the Planning and Review Committee are appointed by the President and Chief Executive Officer and are drawn from MH's senior management group. Current membership of the committee includes:

- Vice-President, Corporate Planning & Strategic Development;
- Division Manager, Transmission Systems Operation;
- Assistant Corporate Secretary;
- Division Manager, Consumer Marketing and Sales;
- Division Manager, Aboriginal Relations;
- Division Manager, Transmission Planning and Design;
- Manager, Government Relations and Current Issues;
- Division Manager, Power Projects Development;
- Manager, Internal Audit; and
- Division Manager, Power Planning.

5.1.4.6 Export Power Risk Management Committee



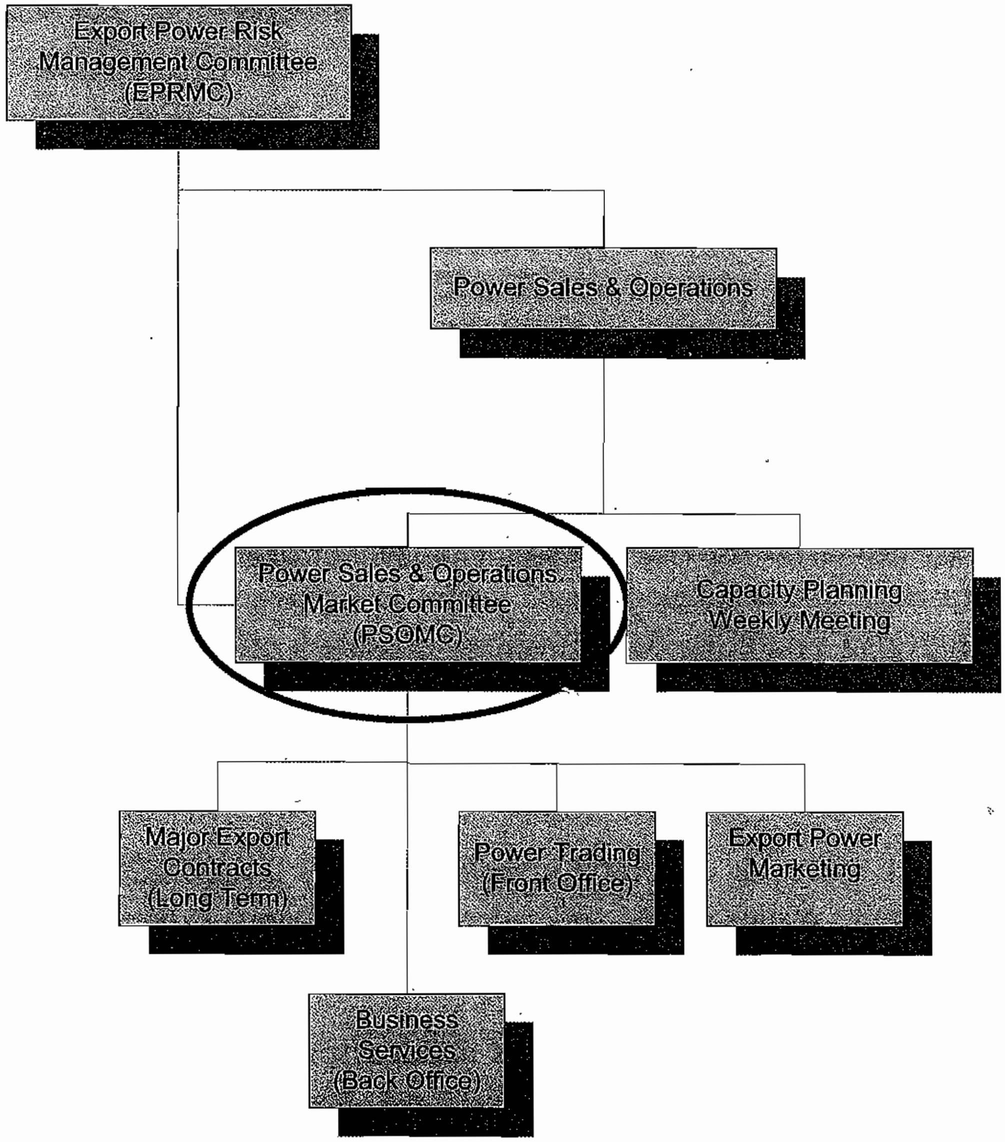
The Export Power Risk Management Committee ("EPRMC") was established in November 2006. According to its terms of reference, the role of the EPRMC is to provide oversight of the management of the energy supply and financial risks resulting from Manitoba Hydro's participation in the export power market. EPRMC is responsible for authorizing and ensuring that the strategies, measurement methodologies and controls for the management of these risks are effective in protecting MH's interests consistent with the corporation's tolerance for risk.

Responsibilities include:

- reviewing and approving criteria for managing risks associated with MH's electrical energy planning and operations; long-term export marketing initiatives; and opportunity export marketing and trading initiatives;
- reviewing and approving MH's export risk management program, including risk tolerance, risk measurement methodologies, risk management strategies and instruments;
- reviewing and approving general drought management strategies, including securing energy supplies, hedging objectives and tools;
- reviewing and approving trading and export market policies and procedures; and
- receiving and reviewing reports and audits of market activities and transactions.

Membership of the committee includes the President and CEO (Committee Chair); the Senior Vice-President, Finance and Administration and CFO; the Senior Vice-President, Power Supply; and the Corporate Secretary and Legal Counsel (Committee Secretary). The Committee receives regular or *ad hoc* reports from division and department managers, including but not limited to: Power Sales and Operations, Power Planning and Development, Corporate Controller and Export Power Middle Office.

5.4.1.7 Power Sales and Operations Market Committee



The Power Sales and Operations Market Committee ("PSOMC") is a management committee within the PS&O division that was established in November 2005 to oversee power transactions. According to the committee's terms of reference, its primary responsibility is to provide coordinated business direction, communication and control regarding energy transactions strategy, practices and procedures, product sales and purchases, and customer relations for Manitoba Hydro's participation in the export power market. Its terms of reference were updated in February 2009. The PSOMC reviews and approves operational activities within the parameters of the Board approved Management Control Plan and the EPRMC endorsed Approval Authority Table for Power Related Transactions, including but not limited to:

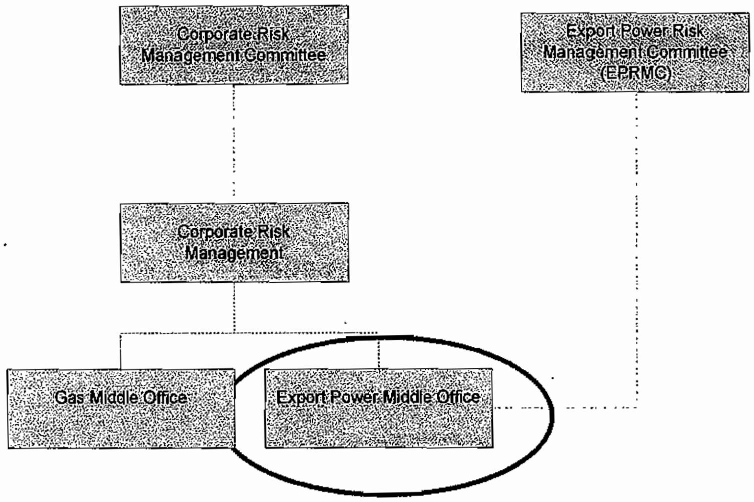
- reviewing, implementing and modifying business procedures;
- reviewing opportunity sales and purchase strategies and forward quantities;

- reviewing merchant sales and purchase strategies;
- reviewing transmission acquisition and maintenance strategies including the nomination, purchase and sale of auction revenue rights and financial transmission rights or equivalent;
- reviewing system financial products strategies;
- reviewing and monitoring export transactions and risk reports;
- reviewing and providing recommendations for approval to the EPRMC regarding:
  - export power sales, marketing and associated business policies;
  - export power marketing strategies and trading initiatives;
  - risk management strategies and hedging activities including drought; and
  - new markets, products and transaction types.

The members of the PSOMC are:

- PS&O Division Manager (Chair);
- Export Power Marketing Manager;
- Power Trading Manager.
- Export Power Middle Office Senior Risk Officer

5.4.1.8 The Export Power Middle Office



The Export Power Middle Office ("Middle Office") was established on February 6, 2007. According to its terms of reference, the Middle Office was initially created to be a review and advisory function reporting to the EPRMC under the direction of the Senior Vice-President of Finance and Administration and Chief Financial Officer.

The Middle Office is responsible for:

- Assessing whether potential risk exposures for export power strategies are identified;
- Evaluating risk treatment mitigation activities;
  - reviewing all formal policy and procedure documents to identify gaps or weaknesses in risk treatment and provide recommendations to improve risk mitigation;
  - reviewing established risk tolerances to determine whether they provide direction in electric export power activities and operations are within the established limits;
- Evaluating the accuracy of risk exposure / measurement information;
  - assessing the quantitative methodologies and systems in place to measure risk exposures;
  - testing methodologies and systems to ensure accuracy and adherence to stated objectives and logic;
  - determining that measurement information is accurately calculated, prepared in a timely manner and clearly communicated;
  - performing stress and backtesting and when appropriate scenario analysis on risk exposures;

- Monitoring export power activities for adherence to established policy, procedures and guidelines and assessing the effectiveness of controls;
  - reviewing export power activities on an ongoing basis and where possible incorporating exception reporting into those systems used for tracking and reporting of trading activities;
  - reporting on weaknesses and all non compliance issues; and
- Reviewing all new products to confirm that the risks around these new products have been identified and report the results of the review.

The Middle Office reports to the EPRMC on a quarterly basis.

5.4.2 Policies

The following key policies establish MH risk management standards and practices:

- Corporate Risk Management Policy
- Management Control Plan ("MCP")
- Power Sales Approval Authority Table
- Export Power Contractual and Legal Policy
- The Power Sales and Operations Credit Management Policy and Procedures
- Manitoba Hydro Wholesale Power Risk Policy (Draft)

To provide further context for our subsequent assessment of the management of opportunity sales risks, the following is a description of these policies:

5.4.2.1 Corporate Risk Management Policy

The corporate risk management policy establishes the corporate-wide risk management program. According to the policy, MH will manage its business and operational risks through a systematic, proactive and integrated process that is designed to balance the objectives of:

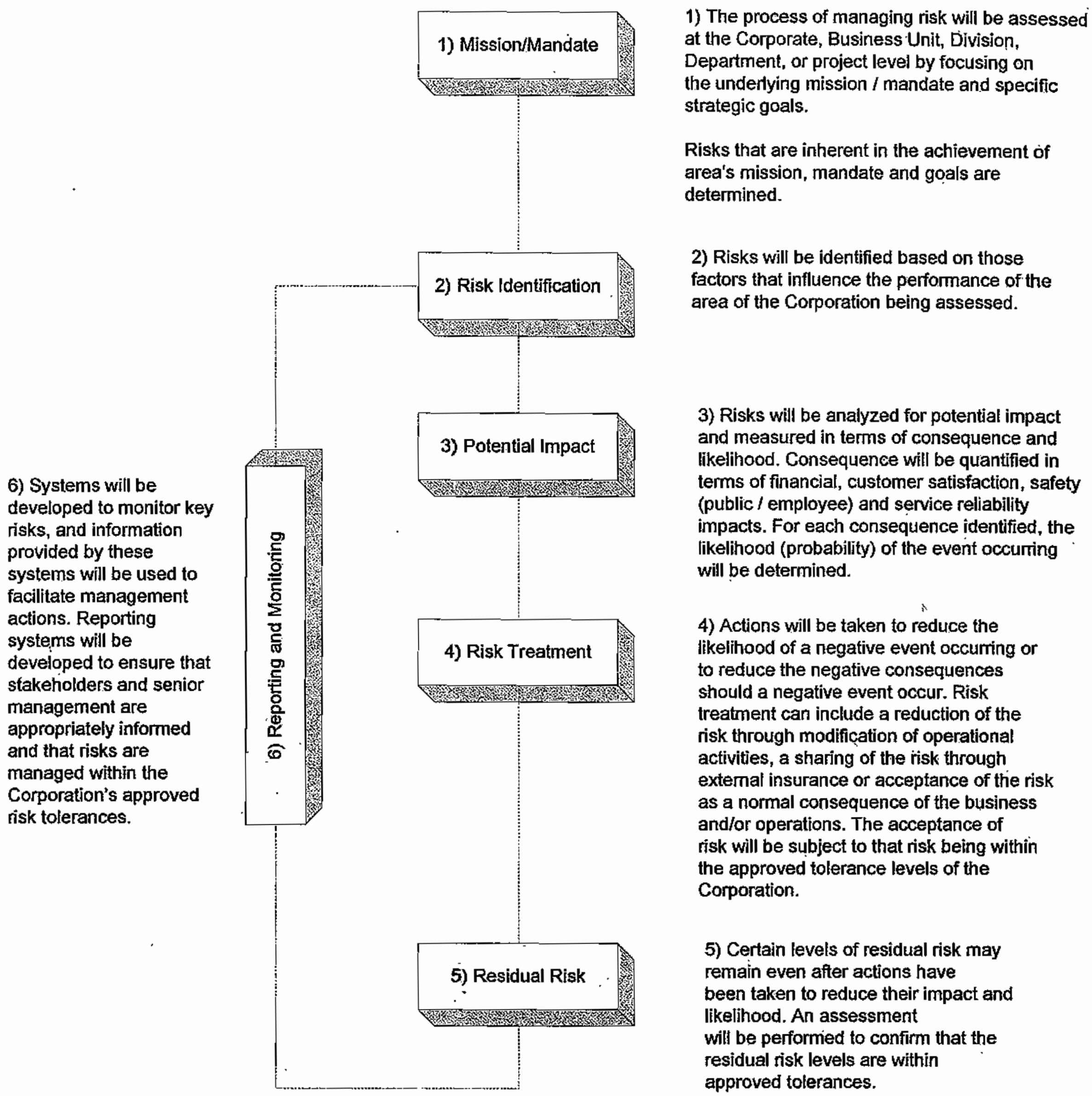
- identifying threats that affect the achievement of MH's mission and mandate;
- mitigating the consequences of negative occurrences; and
- taking advantage of opportunities to provide benefits to all stakeholders.

The policy is supported by the corporate risk management operating procedures that establishes risk management roles and responsibilities, the risk identification process and outputs such as the corporate and business unit risk profiles. These profiles are to be updated on a regular basis to ensure that risks are prudently managed and documentation is kept current.

The procedures require that a risk map will be produced at the corporate level to provide a graphical representation of risks facing the corporation. The risk map will depict risks in terms of consequence and likelihood of occurrence, and will be used to facilitate analysis, prioritization, risk tolerance, assessment, decision making and communication.

A clearly defined process for the identification, assessment and treatment of risk is articulated in the operating procedures document. A six step risk assessment and management process is described. Exhibit 5-3 provides an overview of the process:

Exhibit 5-3: Manitoba Hydro - Risk Management Process



Source: Manitoba Hydro

5.4.2.2 Management Control Plan

On April 25, 2002, the Board of Directors authorized the President & Chief Executive Officer or his/her delegate to execute contracts for the export and import of power and for associated purchases of transmission, fuel and ancillary services. At that time, the Board requested that management develop a risk management plan for the import and export of power. In response to this Board request, management developed the original MCP. It was approved by the Board on June 13, 2002. The MCP has been subsequently updated and approved by the Board in 2005 and again in 2007.

The scope of the MCP covers all power related transactions in both the United States and Canada, including energy and financial products as well as associated transactions for related products, including transmission, fuel, ancillary services and environmental attributes such as emission credits or allowances, and renewable energy credits. It consists of a portfolio of risk management mechanisms to protect the corporation from unnecessary risk or harm as a result of improper business practices. These mechanisms include application of both corporate-wide and divisional policies and procedures, control mechanisms such as signing authority requirements and segregation of duties, sophisticated computerized systems, use of budgets and reporting and review.

The MCP establishes the control framework for the following areas:

- long-term generation adequacy (resource availability);
- short-term resource management;
- system transactions, for energy products and financial products;
- merchant transactions (related or pure merchant), for energy products and financial products; and
- customer credit.

5.4.2.3 Power Sales Approval Authority Table

In January 2006, delegations of authority were approved for power sales. The following are examples of the approval authorities established by Manitoba Hydro at that time:

- any system energy products transaction requiring new generation capacity requires approval by the Executive Committee and the Manitoba Hydro-Electric Board;
- any system energy products transaction from existing generation or any purchase exceeding five years in duration and greater than 100 MW requires approval by the Executive Committee and the Manitoba Hydro-Electric Board; and
- any system energy products transaction from existing generation or purchase exceeding five years in duration and less than 100 MW requires approval by PSOMC.

On October 1, 2007, the power sale approval authority table was modified. The modified table provides an expanded universe of approval authorities required by Manitoba Hydro for the execution of wholesale power transactions and related agreements once the necessary license and regulatory approvals have been obtained. The expanded approval authorities cover the following areas:

- system energy product transactions, for both new and existing generation in terms of megawatt size and contract duration;
- system financial product transactions; that is financial transmission rights, virtual supply or demand bids or offers, and for the use of call and put options and swaps;
- merchant transactions, covering both merchant energy transactions and financial transactions; and
- related agreements (for all transactions), including the master (interchange) agreement, remarketing agreements, market participation agreements, clearing firm and broker agreements, transmission or transportation service agreements, credit and netting agreements, customer creditworthiness requirements and changes and exceptions to these export power sales creditworthiness requirements.

5.4.2.4 Export Power Contractual and Legal Policy

This policy came into effect in September 2007 and is designed to minimize the contractual and legal risk that may arise from a party's misinterpretation of their respective rights and obligations under a contract. Contractual and legal risk may result in costly dispute resolution or unenforceability of the contract. Key controls outlined in the supporting contract documentation and review procedure include:

- terms and conditions for entering into transactions;
- parameters for determining pricing and availability of supply;
- required provisions for contracts ensuring adherence to regulatory, legal and taxation requirements;
- internal review and signoff, including legal review of all written contracts; and
- contract retention and storage requirements.

The policy is supported by detailed procedures which were recently updated (in February 2010). The procedures cover standard contractual requirements, contract review and documentation requirements for energy capacity agreements, transmission access agreements, market plus premium agreements dependable sales agreements, request for proposals and terms sheets and environmental attribute agreements. The procedure also defines the process for amending contracts and contract administration requirements and provides guidance for contract documentation.

5.4.2.5 Power Sales and Operations Credit Management Draft Policy and Procedures

This draft policy and supporting procedures were developed in October 2009 and build upon credit management provisions that are contained in the MCP. These are now the governing documents to manage credit for all wholesale electricity related transactions. Credit management must adhere to the following principles:

- principle 1: establishing an appropriate credit risk environment;
- principle 2: operating under sound credit granting processes;
- principle 3: maintaining appropriate credit contracts, administration, measurement and monitoring processes; and
- principle 4: ensuring adequate controls over credit risk.

The documents provide credit management procedures to grant appropriate counterparty credit limits while mitigating the risk of credit losses. They also identify the tools used to monitor and evaluate the ongoing creditworthiness of MH's export power sales counterparties, and set out procedures to follow if counterparties request financial security from MH. Roles and responsibilities required to support the credit management function are provided.

5.4.2.6 Manitoba Hydro Wholesale Power Risk Draft Policy

In February 2010, the Middle Office at Manitoba Hydro drafted a new wholesale power risk policy that, if adopted by the Executive Committee and the Board of Directors, will become the successor policy to the MCP. The intent of the draft policy is to continue MH's management of risks and related exposures according to the following principles:

- ensuring that Provincial supply needs are met and not put at unjustified risk due to wholesale power activities. All activities should be supported by prudent risk management, power, water and credit management practices;

- risks are managed in a manner that will mitigate or reduce risk and related exposure while balancing opportunities to maximize net export revenue and expected financial outcomes;

- all wholesale power transactions will only be undertaken when there is an expected net benefit to MH as a result of the transactions and transactions will have adequate pricing margins;

- volumes associated with all wholesale power sales should not exceed at the time of commitment, energy availability projections or forecasts related to the duration of the sale;

- wholesale power transactions should be undertaken only with creditworthy counterparties based on maximum pre-defined credit limits, the use of collateral or guarantees when warranted and when appropriate, the use of industry standard agreements;

- activities undertaken must comply with all applicable laws, regulations, tariffs, rules and applicable corporate policies; and

- risk governance infrastructure will maintain adequate oversight, controls, measurement and reporting.

The draft policy provides direction on general transacting policy, anti-speculation in terms of energy and financial products trading, and the risk governance structure at MH including roles and responsibilities for the front, middle and back office functions of the corporation. It identifies other relevant risk management support functions (e.g., Hydraulic Operations, Resource Planning and Market Analysis, Legal, Corporate Accounting, Treasury, Technology and Audit).

The draft policy also provides risk reporting requirements including the Credit Report, Transaction Performance and Position Reports, Policy and Procedure Compliance, Generation System Status, and other information and reports on specific risks when applicable.

5.5 Risk Governance Leading Practices

Leading practice organizations such as the Committee of Chief Risk Officers (CCRO), the International Organization for Standardization (ISO) and the Canadian Standards Association (CSA) have made significant contributions to articulating and maturing the role of risk management from both a strategic enterprise-wide perspective and for specialized risk management functions (e.g., market risk, credit risk, operational risk and strategic business risk). The following table provides a summary comparison of MH's risk management practices for power sales against the leading practices.

The comparison of MH's power sales risk governance practices to the leading practices is positive. Based on the nature of its asset backed power sales business model, the MH risk governance practices are for the most part appropriate. The comparative analysis demonstrates that MH is making progress on maturing its power sales risk management policy framework and its Middle Office in accordance with leading practices.

Exhibit 5-4

Comparison of MH's risk management practices against the leading practices

Legend

No evidence of leading practice

Partially meets the leading practice

Substantially meets the leading practice

Fully meets leading practice

Leading Practice	Manitoba Hydro Practice	Findings	Conclusions	Overall Assessment
1. An independent senior executive (e.g., Chief Financial Officer (CFO) or Chief Risk Officer (CRO) is responsible for overseeing an independent Middle Office function.	The Senior Vice President of Finance and Administration, Chief Financial Officer is ultimately responsibly for overseeing the independent Export Power Middle Office.	This oversight role has been in place since 2006. The Export Power Middle Office reports to the Corporate Risk Manager who in turn reports directly to the Senior Vice President of Finance and Administration, Chief Financial Officer.	Based on the size and nature of the asset backed power sales strategy adopted by Manitoba Hydro, the independent leadership of the Export Power Middle Office is in keeping with leading practice.	
2. The CFO or CRO chairs a risk oversight committee which is responsible for ensuring that power sale risks are identified, assessed and managed according to the corporation's risk tolerances and supporting policies.	The Export Power Risk Management Committee was established in November 2006. The EPRMC provides oversight of the management of the energy supply and financial risks resulting from Manitoba Hydro's participation in the export power market.	The committee is chaired by the CEO. Membership also includes the Senior Vice-President, Finance and Administration, CFO; the Vice-President, Power Supply; and the Corporate Secretary and Legal Counsel (Committee Secretary). It plays a significant role in terms of risk-based decisions for power sales. The Committee receives periodic updates from the Export Power Middle Office on risks and compliance issues.	The EPRMC's oversight and pre-Executive Committee review and approval role fully meets the leading practice.	
3. Risk management policies and procedures are established for power sales and independently monitored for power sales.	Manitoba Hydro has established a series of risk management policies covering power sales including: • The Management Control Plan (2002, 2005, 2007) • The Power Sales Approval Authority Table (2006) • Export Power Contractual and Legal Policy (2007) • Power Sales and Operations Credit Management Policy and Procedures (Draft) (2009) • Manitoba Hydro Wholesale Power Risk Policy (Draft 2010)	Manitoba Hydro has a detailed opportunity sales policy framework that is regularly assessed for compliance by the Middle Office. Ownership of power sales risk management policies has been historically within the domain of PS&O. We understand that MH is considering transfer of the responsibility for power sales risk management policy stewardship to the Export Power Middle Office.	The power sales risk management policy framework substantially meets the leading practices Manitoba Hydro should continue to institutionalize the policy setting roles of the Export Power Middle Office.	

KPMG

Leading Practice	Manitoba Hydro Practice	Findings	Conclusions	Overall Assessment
4. An independent Middle Office has been established which reports directly to the CFO or CRO. It conducts independent risk analysis of power sales from both market and credit risk perspectives.	The Export Power Middle Office was established in 2007 and is staffed by a senior risk officer.	The Middle Office function is currently responsible for: • Power sales risk policy and procedures • Policy/procedure compliance • Risk monitoring and measurement • Risk and compliance reporting • Transaction evaluation. Under leading practice, the Middle Office would also be responsible for counterparty credit risk analysis. This function currently resides with the Export Power Marketing group within PS&O.	The current Middle Office structure partially meets the leading practices. In order to fully meet the leading practice, credit risk analysis should report directly to the Middle Office. The market risk quantification capabilities of the Middle Office should also be enhanced.	◗
5. The Middle Office function is adequately resourced (HR and technology) to carry out independent risk assessments of power sales.	The Export Power Middle Office is currently staffed by one senior risk officer.	Currently the Export Power Middle Office has limited risk analysis resources for both market and credit risk. The current energy trading system, WebTrader, does not have an integrated risk analysis module which provides the Middle Office with the capability to conduct risk analysis against a series of risk metrics. Manitoba Hydro currently has an initiative under way to select a risk analysis software tool that will integrate with its energy trading system.	The current HR and technology resources of the Export Power Middle Office to conduct independent risk assessments of power sales only partially meet the leading practice.	◗

Case Studies

This section of the report presents a summary of our findings related to risk governance approaches of other electric power utilities. It demonstrates that as electric utilities across North America are adapting to their changing environments, a variety of approaches are in place, largely driven by their unique operating characteristics, regulatory regime and the pace at which they are implementing relevant leading practices.

KPMG reviewed 14 other electric utilities as part of its case study review. For the purposes of our analysis on risk governance we have considered 13 of the 14 utilities. The utility excluded from our analysis does not engage in any power sales; thus it is not a relevant comparator. The following table provides a summary of the findings in terms of stated risk governance roles, responsibilities and reporting relationships, and policies in place at the utilities we researched.

Exhibit 5-5

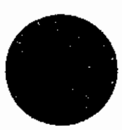
Comparison of Case Study Findings to MH Practices

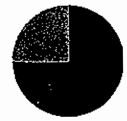
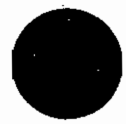
Legend


No evidence of comparative case study findings


Partially aligns with the case study findings


Substantially aligns with the case study findings

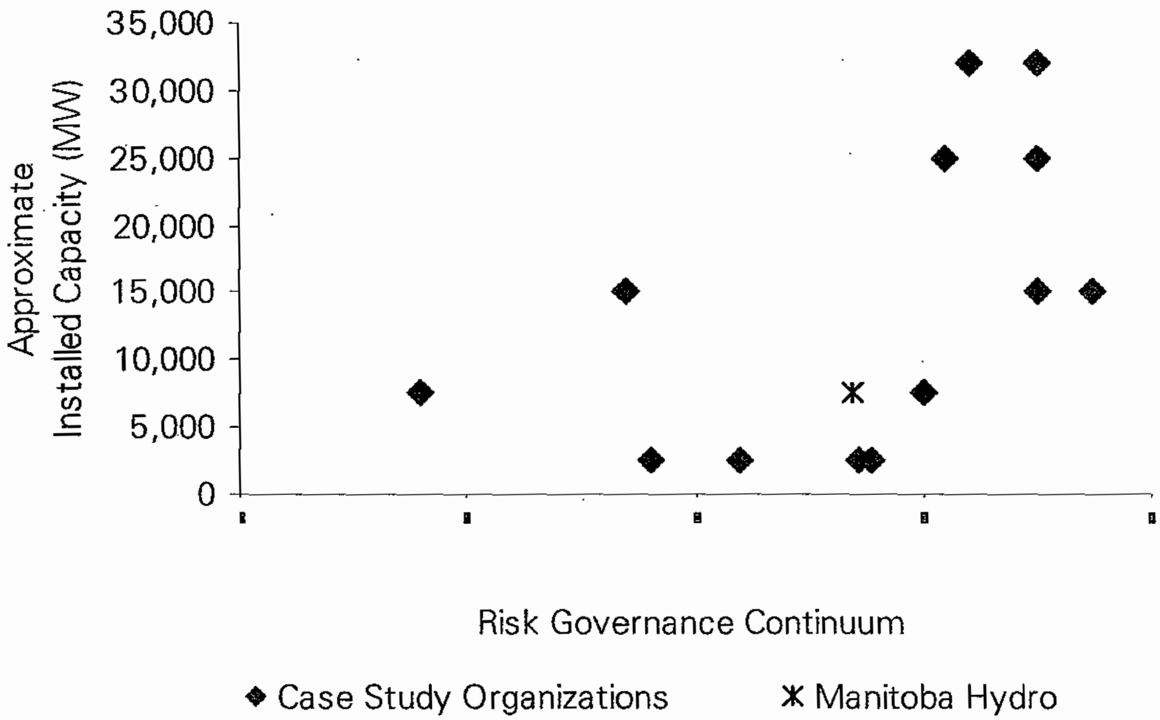

Fully aligns with the case study findings

Case Study Element	Case Study Finding	Manitoba Hydro Assessment
Roles, Responsibilities and Reporting Relationships		
Independent Middle Office	Twelve of the 13 organizations studied have defined front, middle and back office roles and responsibilities. The make-up of the Middle Office is unique across organizations and is dependent on the mandate, trading activity, and policies and procedures of the organization. The number of personnel in our sample of Middle Offices range from one to thirteen dedicated professionals. Typically these professionals are segregated within the Middle Office either by type of risk (i.e., credit, market or operational risk) or by function (i.e., risk planning, risk reporting or risk control).	
Policies		
Risk Management Policy	KPMG's case study review revealed that every organization has a documented risk management policy. Each of the organizations also have more specific risk policies and procedures that outline risk limits, hedging strategies, approval structures, etc. Due to the proprietary nature of such policies KPMG was unable to conduct a detailed comparison to Manitoba Hydro's risk management policy framework.	

5.6.1 Overall Risk Governance Structure

To provide additional context on MH's risk governance practices, we prepared the following scatter plot comparing MH to the results of the case study research. Note that the scatter plot compares the organizations on the basis of their overall risk governance practices pertaining to power sales, and not just to opportunity sales. Exhibit 5-6 below illustrates each organization's risk governance structure along a "risk governance continuum" as contrasted with the approximate size of their generation capacity.

Exhibit 5-6: Risk Governance Continuum



In creating the scatter plot, KPMG considered the five leading practices outlined in Exhibit 5-4, the context of the organization and other pertinent factors as a basis upon which to apply professional judgment to determine each organization's location on the scatter plot.

As seen in Exhibit 5-6, there are three clusters of organizations present in our sample. Four of the organizations are closer to the "basic" end of the spectrum; six of the organizations are closer to the "advanced" end and four of the organizations fall in a middle cluster between the "basic" and "advanced" ends. Note that the organizations that are close to the "advanced" end of the spectrum tend to have significantly larger installed capacity than the other organizations in our sample. MH lands in the middle cluster of organizations, and its risk governance structure is similar to the organizations with installed capacity under 10,000 MW.

5.7 Risk Management Roles, Responsibilities and Reporting Relationships

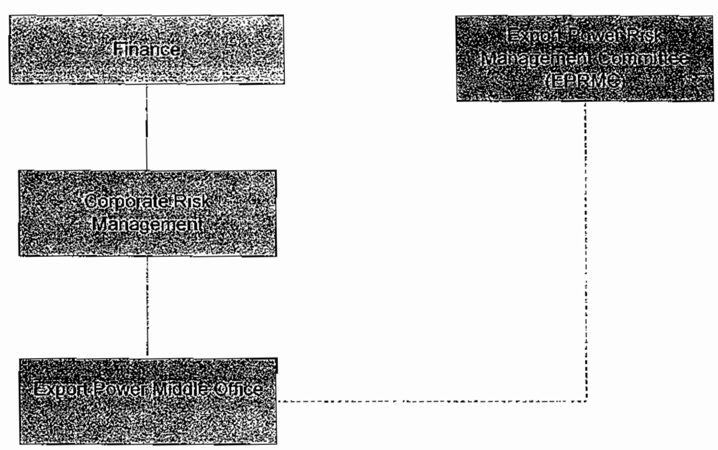
In this section we present our key findings and conclusion with respect to risk management roles, responsibilities and reporting relationships. We have based our findings and conclusions on our understanding of MH's business and risk management practices, the applicability of leading practices to this business, our case study analysis and KPMG's professional risk management experience in the power sector.

The following are our findings on the middle office function at Manitoba Hydro.

The Export Power Middle Office is a single, independent, risk management office and is progressing appropriately toward its responsibilities for assessing the risks of transactions in opportunity sales in the export market.

- The Export Power Middle Office has been established as an independent entity that reports to the Manager, Corporate Risk Management, who in turn reports directly to the Senior Vice-President, Finance and Administration and CFO. MH has effectively segregated the middle office function from the PS&O division, which is responsible for power sales. The Export Power Middle Office has a dotted line reporting relationship to the EPRMC and reports on risk and compliance matters to the committee on a quarterly basis. The following exhibit demonstrates the independence of the Middle Office:

Exhibit 5-7: Reporting Relationship of the Export Power Middle Office



- The Export Power Middle Office provides advice and assistance to PS&O on risk assessment methods and calculations for energy transactions. It also fulfills an important risk policy compliance role for MH.

- There has been steady progress at MH towards a fully functioning Middle Office, as evidenced by changes in reporting relationships and policies described in section 5.4 (e.g., creation of EPRMC and independent Middle Office reporting to the CFO). The evolution of the middle office function at MH is not dissimilar from what we observed from the case study participants. The case studies demonstrated that the core requirements and time frame for maturing the middle office function are by-products of the power utility's complexity from a business model, asset base and power trading perspective. The nature and volumes of transactions are factors in determining how extensive the Middle Office's role has become.

MH should consider empowering the Export Power Middle Office to provide both independent credit and market risk analysis

- Leading practice suggests progressively moving to a fully independent Middle Office function with strong risk management capabilities for both market and credit risk. These functions are currently found in PS&O, which does not allow fully independent oversight.

- Credit risk management for counterparty transactions is most effective when it is performed at an independent Middle Office level rather than within the power trading and marketing area.

- MH (and other utilities) have certain market risk assessment functions housed in the power trading business unit to support the assessment of market risk exposure. While not ideal from an independence perspective, there are operational efficiencies associated with this approach.

The Export Power Middle Office should continue its efforts to improve its risk analytics capabilities.

- Currently, the Export Power Middle Office is staffed by a senior risk officer with a strong background in financial and risk analysis. The Export Power Middle Office risk quantification capabilities would be enhanced through the addition of a market risk analyst position to support the risk officer. This would also complement MH's current initiative to invest in risk analysis software that can be integrated with its energy trading software –WebTrader.

- The Middle Office should have the necessary core risk assessment and quantification methods and systems to independently assess the risk profile of all opportunity sales transactions. This is consistent with leading practice and a number of our case studies. It would provide more timely and insightful management information.

- MH has acknowledged that its current power transaction system WebTrader does not have an integrated risk analysis module. It has also recognized that spreadsheet-based risk analysis tools may not be the most efficient or integrated way to assess the risk associated with opportunity sales. As a result, MH is currently developing detailed functional requirements for its Middle Office risk analysis system. It is assessing core risk measurement requirements with leading energy risk analysis software offerings in the market. As part of this undertaking it has issued an Expression of Interest (EOI), and has invited vendors to provide on-site demonstrations of their solutions. This market scan and demonstration phase will lead to a comprehensive Request for Proposals (RFP) phase to acquire a solution that integrates with the current transaction management system. These initiatives by MH will further enhance the capacity and efficiency of the risk analytics capabilities of the Export Power Middle Office.

5.8 Risk Management Policies

In this section we present our key findings and conclusion with respect to risk management policies. We have based our findings and conclusions on our understanding of MH's business and risk management practices, the applicability of leading practices to this business, our case study analysis and KPMG's professional risk management experience in the power sector.

MH's policies concerning opportunity power trading are progressing appropriately for the nature of its business.

- MH has established both the Board of Directors' and the senior management's commitment to establishing policies at the corporate and business unit level to manage the corporation's risks with a strong focus on power sales. For example, this is demonstrated in the Audit Committee Charter and in the delegated authority to the Executive Committee and the EPRMC.

- Since 2002, MH has had the Management Control Plan and the Table of Authorities for a range of power transactions in order to control the risk of unauthorized sales or financial transactions. The Table of Authorities was updated in 2007 to reflect the changing nature of MH's transactions.

- Since 2007, the Export Power Contractual and Legal Policy has been in place and is designed to minimize the contractual and legal risk that may arise from a party's misinterpretation of their respective rights and obligations under a contract. The policy is designed to mitigate contractual and legal risk that may result in costly dispute resolution or unenforceability of an export power contract.

- The Power Sales and Operations Credit Management Policy and Procedures were developed in October 2009. They build upon credit management provisions that are contained in the Management Control Plan. These are now the governing documents to manage credit for all opportunity wholesale electricity related transactions.

- According to our case study review it was found that every organization has a documented risk management policy. Each of the organizations also has specific risk policies and procedures that outline risk limits, hedging strategies, approval structures, etc. MH's risk policy framework is in keeping with these findings.

MH should continue its effort to institutionalize the policy setting role regarding risk management of the Middle Office in accordance with leading practices.

- The recent drafting of the revised export power wholesale marketing (February 2010) and credit policies and procedures (October 2009) indicates that MH is maturing and aligning the opportunity export power marketing risk management governance and policy framework with leading practices.

- We understand that recently (March 2010) a plan has been developed to consolidate contract and credit procedures into one set of risk management guidelines and procedures document. It would include a new section for risk management procedures on all types of transactions and would flow from a final approved new risk policy.

- We understand that a plan has been developed to consolidate the stewardship for opportunity power sales risk management policy development and renewal under the Export Power Middle Office. This is an appropriate and consistent approach to developing, integrating and maintaining its opportunity sales risk management framework going forward.

The leading practice suggests a comprehensive and integrated approach to developing and managing risk management policies. Manitoba Hydro's current risk management policy consolidation initiative is in keeping with such practice.

5.9 Conclusion

In terms of risk governance, based on our analysis, we conclude the following:

- MH's power sales are asset backed. These sales are generally low risk and the MH risk governance policies and reporting relationships, including the role of the Middle Office, are evolving appropriately.

- The Export Power Middle Office is a single, independent, risk management function. It is steadily progressing in terms of its responsibilities for measuring, monitoring, controlling, and reporting the risks associated with PS&O's opportunity power sales activity.

- The Export Power Middle Office is undertaking an initiative to improve its risk analytics capabilities. It requires further resource(s), supported by risk analytics software that is integrated with Manitoba Hydro's energy transaction management system (WebTrader). The timeliness of this risk monitoring will continue to improve with added analytical resources and related technology.

6

6. Power Risk Management

Power risk management is the process by which a utility identifies, measures, controls, and reports risk associated with its energy transacting activities.

This chapter is organized as follows:

- 6.1 Scope of Our Review
- 6.2 Key Findings
- 6.3 Approach and Methodology
- 6.4 Risk Identification
- 6.5 Risk Measurement
- 6.6 Risk Control
- 6.7 Risk Reporting
- 6.8 Conclusion.

6.1 Scope of Our Review

In Phase 1 of the Review and as shown in Exhibit 1-1, KPMG identified one Issue within the Theme of Power Risk Management:

- Issue – Treatment of risk (identification, measurement, treatment)

To summarize the Consultant's assertions on this Issue, the Consultant asserts that MH is not adequately analyzing its risks associated with export power sales by breaking the risks into its component sub-risks and using a structured framework for assessment. The assertions relate to risk identification, risk measurement, risk control and risk reporting.

In addition, as noted in Section 1.2.1 of this report, another Theme (Portfolio Monitoring and Reporting) and the related issue (methodology for valuation and hedging (mark-to-market)) identified during the conduct of our Phase 1 work were merged into the Theme of Power Risk Management, and the related Issue consolidated with the treatment of risk issue, because of the high level of overlap in content.

In accordance with the general approach outlined in Chapter 1, our assessment of these issues has been extended beyond the specific subject matters addressed by the issues as defined in the Phase 1 report. Specifically, our assessment of power risk management considers the issues in the context of a typical risk management framework containing the following elements:

- Risk identification;
- Risk measurement;
- Risk control; and
- Risk reporting.

For each of these risk management framework elements, one or a number of topics were identified of relevance to power risk management and the issues raised. These are identified in Exhibit 6-1.

Exhibit 6-1: Power Risk Management Framework

Risk Identification	Risk Measurement	Risk Control	Risk Reporting
Major Export Contracts	Mark-to-Market Risk Analytics Credit Risk Management	Risk Limits Transaction Processing Controls	Adequacy of Existing Reports

In relation to each topic included above, one or a number of questions were identified as a means of addressing the subject matter of the chapter and framing the analysis covered in this chapter. These include:

Major Export Contracts

- *Are inherent risks associated with prospective major export contracts identified in a systematic and disciplined manner?*
- *Are prospective major export contracts reviewed by relevant internal stakeholders (i.e., legal, regulatory affairs, environmental, etc.)?*

Mark-to-Market

- *Should MTM be applied to measure market, credit and volumetric risks?*

- *Should physical gas assets (e.g., gas storage) and its embedded optionality characteristics be marked to market?*

- *Does MH apply proper accounting treatment to its long-term sales contracts consistent with Generally Accepted Accounting Principles (GAAP)?*

Risk Analytics

- *Should a VAR-based method be considered to measure drought risk?*

- *Is the current stress testing methodology reasonable?*

- *Should backtesting be performed to calibrate and validate model assumptions?*

Credit Risk Management

- *Does MH measure credit exposure in a manner consistent with leading practices?*

Risk Limits

- *Does MH have appropriate risk limits commensurate with PS&O power transacting activities?*

Transaction Processing Controls

- *Are MH's transaction processing controls consistent with leading practices?*

Adequacy of Existing Reports

- *Are MH risk reports comprehensive?*

- *Are reports accurate and complete?*

- *Are variance reports produced to compare actual versus forecasted data?*

6.2 Key Findings

This section outlines our key findings with respect to power risk management. Aspects associated with drought-related risks have been addressed in Chapters 3 and 4.

In the context of risk identification:

- While MH has documented contract review procedures, they do not explicitly include risk identification, assessment and risk mitigation strategies. MH should consider expanding these procedures to include these items.

- Major export contracts undergo extensive review by internal stakeholders prior to executing binding term sheets. We suggest that the Middle Office also be involved in the review of export contracts.

In the context of risk measurement:

- MH should consider extending its current practices of using Mark-to-Market (MTM) methodologies to measure and monitor its short-term physical transactions and its credit risk exposures (i.e., replacement cost);

- MH quantifies drought risk using a non-probabilistic stress test, an appropriate measure. MH should also consider developing a probabilistic stress test to further assist management decision-making.

In the context of risk control:

- MH has specified risk limits limited to "Power Related Transactions" in the area of Merchant Transactions (Related or Pure Merchant) and Customer Credit. MH continues to enhance its limit structure, for example, by recently establishing Stop Loss Limits. We recommend that MH continue developing further limits such as Value-at-Risk (VAR) limits for Related Merchant Transactions.

- MH employs a wide range of control mechanisms to mitigate operational risk throughout the transaction process in a reasonable manner. Based on our experience with peer utilities, MH transaction controls are consistent with prevalent practices.

In the context of risk reporting:

- MH risk reporting is generally consistent with leading practice except in the area of "Exposure vs. Limits" reports. We recommend MH expand its report suite to include this key report.

- Variance reports are produced at MH to compare actual against forecasted data for all of its forecasted data and in adequate detail and structure.

6.3 Approach and Methodologies

We analyzed both MH-provided data and external sources to formulate our conclusions and recommendations. Our analysis approach included the following activities:

- a review of how MH manages the inherent risks associated with export power transacting (short- and long-term);

- a review of risk management leading practices in the energy industry; and

- a review of applicable risk management practices from other electric utilities described in **Appendix E.**

Obtaining information on power risk management practices at MH provides the basis for the analysis described in this chapter. In essence, the analysis consist of comparing MH's practices with leading practices (and case study information where applicable) in order to identify gaps and opportunities for improvement.

6.3.1 A Note on Leading Practices

Leading industry risk management practices were gathered from a diverse set of authoritative sources, listed in **Appendix M.**

It is important to note that leading practices are aspirational, continue to evolve and are subject to limitations:

- Leading practices offer insight into an organization's risk management capabilities, and a directional compass for an organization's risk management development. However, the development and implementation of such practices does not assure that control objectives will always be achieved.

- Many leading practices reflect the capabilities of organizations that primarily transact and manage risk in the more traditional financial markets. Requirements of organizations transacting in the energy markets can be different, and in this context, leading priorities should be modified accordingly. In addition, the adoption of leading practices should be considered in the context of costs versus benefits.

6.4 Risk Identification

Risk identification is a requisite component of an effective risk management framework. Before a company can begin managing its inherent risks, the risks must be identified and defined. Management consensus on key risk categories (e.g., market, credit, operational, regulatory, legal, environmental, reputational, etc.) and corresponding definitions establishes the company's risk taxonomy.

MH is a unique utility holding a natural long position in energy supply. MH's experience transacting in the extraprovincial wholesale electricity business initiated with the first transmission interconnection in 1958. Short-term trading began in 2001.

MH participates in the wholesale energy markets by exporting surplus power only to capture market opportunities, generate incremental income, and to ensure market access for current and future domestic needs.

The overall breadth of MH transacting activities are low risk in nature due to the short duration of the majority of their power trading activities. Coupling the low risk with the conservative risk management practices in place, MH manages its market, credit and volume risks in a prudent manner.

The area of MH's power risk management where risk identification is critical relates to its export power sales. This is because non-export sales are made in the context of a regulated utility environment. Within export power sales, it is primarily long-term contracts that raise issues related to risk identification (and measurement and mitigation) because short-term contracts are low risk. This is where we focused our analysis.

A critical success factor to effective risk identification is establishing an agreed upon risk taxonomy. For the purposes of this report, we have identified and defined applicable risk categories in **Appendix L** – Risk Definitions to facilitate a consistent understanding of our observations and recommendations. In this regard, it is noted that there is little industry consensus on definitions for each risk category mentioned.

Risk definitions reflect the organization's unique business model and core activities. For purposes of this report, it is necessary to define PS&O risks upfront to facilitate a consistent understanding of our observations and recommendations, and we have done so in **Appendix L** – Risk Definitions.

PS&O's inherent risks are related to its current scope of authorized transacting activities summarized in Exhibit 6-2.

Exhibit 6-2: Power Sales & Operations – Scope of Authorized Transacting Activities

Product	Commodity	Counterparty	Purchase	Sale
Real time	Electricity	Bilateral, Market	☒	☒
Day ahead	Electricity	Bilateral, Market	☒	☒
Short-term ($x \leq 1$ yr)	Electricity	Bilateral	☐	☒
Long-term ($x > 10$ yrs)[17]	Electricity	Bilateral	☐	☒
Short-term	Natural gas	Bilateral	☒	☒
Exchange-traded products (futures, options)	Electricity and Natural Gas	Market	☒	☒
Over-the-counter products (forwards, options, swaps)	Electricity and Natural Gas	Bilateral	☒	☒
Financial Transmission Rights	Transmission	Market	☒	☒
Ancillary Services	Electricity and Transmission	Market	☒	☒

6.4.1 Long-Term Export Contracts – Risk Identification

Specifically within PS&O, the Major Export Contracts function (i.e., "MEC") within PS&O is responsible for managing and negotiating major export contracts.[18] The MEC came into existence in 2008. Prior to that time, the Export Power Marketing ("EPM") department was responsible for managing and negotiating major export contracts. We understand that the purpose of this organizational change was to allocate a dedicated resource to better manage the term sheet due diligence process. MEC currently comprises one full-time equivalent position, the MEC Manager.

[17] *Long-term sales contracts are offered in two standard products – 1) System Participation Sales and 2) Diversity Exchange Agreements. (See Appendix G for a detailed description of each contract).*

[18] *Major export contracts are a subset of long-term contracts.*

MEC is currently negotiating term sheets with three U.S. utilities Northern States Power (NSP)[19], Wisconsin Public Service (WPS) and Minnesota Power (MP). MEC provides formal progress updates on the negotiations to the Senior Vice-President Power Supply and MH President through the "PS&O Monthly Report".

As previously described in Chapter 4 – Power Sales Management, major export contracts include two types of long-term surplus sales contracts:

- System participation power agreements; and
- Diversity exchange agreements

This section addresses the following long-term contract risk identification issues:

- *Are inherent risks associated with prospective major export contracts identified in a systematic and disciplined manner?*
- *Are prospective major export contracts reviewed by relevant internal stakeholders (i.e., legal, regulatory affairs, environmental, etc.)?*

6.4.1.1 Leading Practices

KPMG considered the following leading practices in assessing MH's risk identification process for major export contracts:

- *"The front office should develop new business after extensive research; it should document the information in a market business plan or risk analysis report. This documentation includes, but is not limited to, industry background, entry and exit plans, risk analysis, return on investment, and proposed limits. Before its plan is approved, the middle office should validate the appropriateness of the market research, models, curves, and assumptions used to value the new business. Additionally, the middle office should independently identify and quantify the various risks involved in accepting the new business activity." (Source: "CCRO Governance and Controls Whitepaper," November 2002, Vol. 2, pg. 18.).*
- *"Potential events that might have an impact on the entity must be identified. Event identification involves identifying potential events from internal or external sources affecting achievement of objectives. It includes distinguishing between events that represent risks, those representing opportunities, and those that may be both. Opportunities are channelled back to management's strategy or*

[19] *The NSP term sheets have now entered the contracting phase, undergoing negotiations and pending counterparty approval.*

objective-setting processes." (Source: "COSO Enterprise Risk Management – Integrated Framework," September 2004, pg. 22.).

- *"Depth, breadth, timing, and discipline in event identification vary among entities. Management selects techniques that fit its risk management philosophy and ensures that the entity develops needed event identification capabilities and that supporting tools are in place. Overall, event identification needs to be robust, as it forms the basis for the risk assessment and risk response components." (Source: COSO Enterprise Risk Management – Integrated Framework," September 2004, pg. 45.)*

6.4.1.2 Analysis

Issue #1: Are inherent risks associated with prospective major export contracts identified in a systematic and disciplined manner?

MH's current contract review procedures, documented in November 2007, prescribe detailed documentation guidelines related to long-term commercial terms and operational parameters (e.g., delivery point, curtailment provisions). However, these guidelines do not include procedures addressing contract risk identification, assessment and risk mitigation strategies.

Issue #2: Are prospective major export contracts reviewed by relevant internal stakeholders (i.e., legal, regulatory affairs, environmental, etc.)?

MH develops forecasts of Dependable Energy and a forward-looking Power Resource Plan. This identifies the amount of firm surplus energy available for sale under long-term contracts. (See Chapter 4 – Power Sales Management for further details)

Volumes available for export sale must conform to the Dependable Energy Criteria Policy. The long-term dependable supply is based on the Power Resource Plan prepared by Resource Planning and Market Analysis (RPMA) who are independent of PS&O and report to the Senior VP Power Supply. Once volumes are deemed available for export sale by RPMA, MEC creates draft term sheets for internal review. The MEC internal review process is required to comply with provisions stipulated in the following policy and procedures documents:

- Management Control Plan;
- Contract Documentation and Review Procedures; and

- Generation Planning G195[20].

Term sheets undergo a lengthy negotiation process (e.g., averaging two to four years) and MEC provides formal progress updates on the negotiations to the Senior VP Power Supply and MH President. During the internal review process, draft terms and conditions are reviewed by the following MH departments / personnel / oversight committee:

- Executive Committee
- EPM Contract Administration;
- Law Department;
- Power Planning Division;
- EPM Transmission Access;
- Manager, Business Services, PS&O; and
- Manager, Power Trading.

MEC may seek additional review and feedback, as determined by the MEC Manager, from the following business areas:

- Transmission;
- Public Affairs;
- Rates and Regulatory Affairs;
- Power Projects Development Division;
- New Generation Construction; and
- Aboriginal Relations.

Major export contracts undergo extensive review by internal stakeholders, except by the Middle Office. We note that long-term contract policies do not stipulate that Middle Office review and feedback is required.

---

[20] *The Generation Planning G195 is a corporate policy statement included in the Management Control Plan providing guidance on resource reserve requirements and the minimum resources needed to provide firm dependable energy under the lowest recorded river flow conditions.*

The MEC internal review process also requires Power Supply to review draft term sheet provisions and acknowledge their review on a "sign-off sheet". However, the "sign-off sheet" does not appear to be utilized in practice. MH management has indicated that internal stakeholder feedback on preliminary term sheet provisions is collected on a real time basis.

MH management indicate that the internal review process has remained consistent when MEC was part of EPM and thereafter.

6.4.1.3 Recommendations

- MH should consider enhancing its major export contracts internal review procedures by documenting its internal review process.

  KPMG recognizes that System Participation Power and Diversity Exchange Agreements are relatively standard MH contracts. However, when a new export contract is executed, it adds incremental risk and opportunity to MH's power portfolio. In its contracting process to date, MH has mitigated its incremental risk by securing firm transmission capacity and expanding import capability. To ensure that similar mitigation strategies are adopted in the future, MH should consider documenting its risk identification and assessment procedures to institutionalize MH's existing informal internal review process.

  The industry-accepted process used to identify risks associated with new and existing products is referred to as the new product process (NPP). The NPP guides management in analyzing all commodity products, instruments and markets related to trading and marketing activities. New and existing products, if not properly reviewed and implemented, can adversely impact MH's risk profile. These products may result in modified risk profiles due to, for example, differing pricing mechanisms, complex embedded options, or incomplete risk decomposition.

  The NPP's primary objective is to validate that all significant risks associated with commodity products have been identified and integrated into the existing risk measurement process and control structure. Second, the NPP helps educate and focuses senior management and relevant functional personnel (e.g., Treasury, Trading, Legal, Tax, Accounting, Risk Management, Regulatory Affairs, Public Affairs, Resource Planning, etc.) attention to the product's inherent risks. Finally, it provides management with a structured framework allowing relevant functional areas to provide input into new product research and development.

An example of an NPP process can be found at Salt River Project, one of the utilities in KPMG's case study review. Salt River Project has established a Complex Deal Committee comprised of managers from the front, middle and back offices. The committee reviews potential new counterparties and agreements to ensure they provide input in their area of expertise. In addition, every contract is reviewed by several groups in the organization including legal, accounting resource planning, energy risk management and regulatory affairs. Any contract with a tenor greater than five years requires approval from the Board and the risk oversight committee.

- MH should consider amending long-term contract policies to require Middle Office participation in the major export contracts internal review process.[21]

  As specifically previously mentioned in CCRO Governance and Controls White Paper, November 2002, Volume 2, page 18 leading industry practices calls for the middle office to validate the appropriateness of the front office's market research, models, curves and assumptions used to value new business (i.e., new long-term contracts).

  Current MH policy does not require Middle Office input in the internal review process. Middle Office input would provide a compliance perspective and a risk mitigation perspective. Specifically, Middle Office participation would enable discussions on whether appropriate strategies are in place to remediate any incremental exposures that materially change MH's risk profile.

- MH should comply with the MEC sign off requirement in accordance with existing policies.

  As mentioned previously, the MEC internal review process requires Power Supply to review draft term sheet provisions and acknowledge their review on a "sign-off sheet". Sign off requirements serve as a key evidentiary control indicating appropriate functional personnel have assessed the inherent risks associated with every major export contract. Signatures also foster individual accountability whereby any delegated proxies who participate in the review process possess the requisite background and professional experience.

[21] *Major export contracts represent significant endeavours and are not a frequent transaction type. Given the low transaction volume and the time it takes to finalize term sheets, Middle Office participation does not have significant resource requirements.*

6.5 Risk Measurement

Risk measurement refers to a company's quantification of its risk exposures. Risk measurement is a prerequisite step to risk mitigation and hedging, and should be comprehensively applied to firm-wide risks. However, not all risks are readily quantifiable. In circumstances where quantification is not a feasible option, qualitative measures are a suitable alternative. In power sales, risk measurement is primarily tied to the assessment and reporting of fair value (mark-to-market) and risk exposure (at-risk measures, stress testing) amounts associated with an organization's open commodity positions. Risk measurement leads to financial performance measures to mitigate earnings volatility, evaluate profit drivers, manage credit risk, assess hedge effectiveness and efficiently allocate risk capital.

The most prominent risk in trading is price risk, i.e., the risk of an economic loss caused by the decrease in the market value of a portfolio of contracts. Three key types of analytical price risk measures are:

- non-statistical or scenario-based measures;
- statistical measures; and
- stress tests.

A non-statistical measure of price risk is the calculation of the contract's or portfolio of contracts change in market value that would occur for a particular scenario (i.e., for a particular change in each market factor affecting the portfolio) independently of the likelihood of that scenario occurring.

A statistical measurement of price risk, in contrast to non-statistical analysis, is the potential loss of a portfolio's market value at a specified confidence level rather than for a specific scenario. In effect, one measures the probability distribution of the potential changes in the portfolio's value corresponding to thousands of scenarios of potential changes in market factors, with each scenario having a particular probability of occurrence. Value at Risk (VAR) is an example of statistical measurement of price risk.

Stress testing is another form of measuring price risk. Stress testing can be either non-statistical or statistical in nature. A non-statistical stress test, tests the potential economic loss of value of a contract (or a portfolio of contracts) for a specified scenario of very large changes in market factors (e.g., water flows in a hydro system). A stress test would calculate VAR under non-standard conditions (e.g., at a confidence level that is much higher than usual or with non-standard volatility or correlation assumptions).

This section addresses issues associated with the following risk measurement topics:

- mark-to-market;
- risk analytics; and
- credit risk management.

6.5.1 Mark-to-Market

Mark-to-Market (MTM) is a methodology used to value open, fixed-priced positions using forward market prices as a proxy. MTM reflects how much the open, fixed price position is worth if it were sold today at the current and projected forward prices prevailing over the term of the position. MTM represents the transaction's fair market value, over its remaining life, if it was liquidated in today's market. MTM measures *unrealized* gains and losses prior to contract settlement by calculating the difference between the transaction price and the forward dated market price.

The prevalent practice in the energy industry is to MTM transactions and portfolios, as a method of monitoring changes in value due to forward market price changes. For a trading portfolio, where the transacting objective is to capture changes in value over time, transactions are MTM in order to measure unrealized profits and losses as they occur. These profits and losses are typically monitored against pre-determined limits specifying the maximum acceptable loss for that transaction (i.e., stop loss limit). As such, this represents a key risk control mechanism.

MTM is also used to measure hedge effectiveness from an economic perspective (i.e., non-accounting perspective). A hedge is a transaction put into place to reduce the effect of adverse price movements on an asset. The hedge transaction consists of taking an offsetting position to the asset being hedged such that the effect of the adverse price movement on the hedge is opposite to the effect of the adverse price movement on the asset. A hedge is said to be effective when the magnitude of the price movement on the hedge and the asset are almost equal (albeit of opposite signs). As such, the MTM value of the asset and the MTM value of the hedge should be almost equal, but of opposite signs. Hence, for a hedged portfolio, measuring the MTM change is a convenient method of measuring hedge effectiveness through a single number, especially for a portfolio with many contracts (and hedges).

MTM is also relevant for calculating credit exposures. Credit exposure arises from a counterparty potentially defaulting on an existing contract. The potential default would result in the non-defaulting party having to either liquidate or replace the contract at current and projected forward prices. Since MTM reflects how much the open, fixed price position is worth if it were sold today, it is a useful tool to quantify credit risk exposure. (See Section 6.5.3 for further detail.)

This section addresses the following MTM issues:

- *Should MH use MTM to measure market, credit and volume risks?*
- *Should physical gas assets (e.g., gas storage) and its embedded optionality characteristics be marked to market?*
- *Does MH apply proper accounting treatment to its long-term sales contracts consistent with Generally Accepted Accounting Principles (GAAP)?*

6.5.1.1 Leading Practices

KPMG considered the following leading practices in assessing MH's MTM practices:

- *"Marking to market is the only valuation technique that correctly reflects the current value of derivatives cash flows to be managed and provides information about market risk and appropriate hedging actions." (Source: "Derivatives: Practices and Principles", G30 Global Derivatives Study Group, July 1993, pg. 9.)*
- *"Organizations should have "market risk measurement systems commensurate with the size and nature of their holdings. Institutions with significant holdings of highly complex instruments should ensure that they have independent means to value their positions. "...Institutions relying on third parties for market-risk measurement systems and analyses should fully understand the assumptions and techniques used by the third party." (Source: Federal Reserve Board of Governors "Trading and Capital Markets Activities Manual", February 1998 edition, Overview of Risk Management in Trading Activities Section 3000.1 pg. 14.)*
- *"All major risks should be measured explicitly and consistently and integrated into the firm-wide risk management system. Systems and procedures should recognize that measurement of some types of risk is an approximation and that some risks, can be very difficult to quantify and can vary with economic and*

market conditions. Nevertheless, at a minimum, the vulnerabilities of the firm to these risks should be explicitly assessed on an ongoing basis in response to changing circumstances." (Source: "Trading and Capital Markets Activities Manual", Federal Reserve Board of Governors, February 1998 edition, Overview of Risk Management in Trading Activities Section 2000.1 pg. 4.)

- *"...where a firm is using its own internal estimate to produce a valuation, it should document in detail the process followed in order to produce the valuation." (Source: "Senior Management Arrangements, Systems and Controls", FSA Handbook, Release 065, May 2007, Section 16.1.12, pg. 6.)*

6.5.1.2 Analysis

Issue #1: Should MH use MTM to measure market, credit and volume risk?

MH's MTM practices have remained consistent from 2006 through to February 2010.

The majority of MH MTM practices are limited to measuring market risk associated with financial transactions, including options and swaps (i.e., contract for differences). Market risk associated with physical transactions, both short and long-term (i.e., export contracts) are not MTM.

Regarding credit risk measurement, MH does not measure the replacement cost of power (in the event of counterparty default) using MTM methodologies as described previously.

Volume risk refers to unexpected electricity supply variances as a result of uncertain water flows. The random nature of these water flows is a result of natural phenomena. For example, precipitation is concentrated in particular seasons depending on weather patterns. Price movements may follow changing water flows (e.g., drought causing price spikes), however, the reverse relationship is not true. Therefore, the range of volume uncertainty can vary more erratically than its price counterpart. Hence, combining volume and price uncertainty has a multiplicative effect generating a large potential range of outcomes.

An additional complicating factor in volume risk measurement is the inherent operational flexibility of MH's hydro system (i.e., MH's ability to store limited amounts of water in plant forebays to use during on-peak periods). Thus, by shifting some incremental production to typically higher priced on-peak periods, MH can offset, on a percentage basis, some of the revenue loss from lower water volumes. Moreover, MH can take comparatively more advantage of forebay storage capacity in moderate water years as compared to extremely high water years (when there may be no forebay storage available), and low water years (when there may not be enough water to store).

Measuring volume risk using traditional MTM practices pose practical challenges for MH due to the above complications and the lack of published long-term forward electricity prices.

In lieu of MTM, MH practices an industry-accepted proxy referred to as mark-to-model by using third-party[22] long-term energy price forecasts and modeling low, expected and high flow scenarios. The long-term price forecast represents the MINN hub, which is adjusted by MH to reflect the contract delivery location (i.e., MHEB hub).

Issue #2: Should physical gas assets (e.g., gas storage) and its embedded optionality characteristics be marked to market?

MH does not currently have equity ownership in any natural gas storage facilities. During drought years, PS&O may procure adequate gas storage facilities from Tenaska Marketing Ventures / Tenaska Marketing Canada (collectively TMV) or other supplier with the intent to inject gas and withdraw to fuel MH's thermal plants, as necessary. These gas purchases are viewed as necessary to firm up fuel supply and as "insurance" against spot electricity price volatility in the event MH is short supply to serve provincial load. MH does not hold gas storage capacity during normal water years and has leased gas storage facilities only once during the 2003/04 drought.

Since MH uses gas storage only as an integral part of its drought management strategy and does not hold storage during normal water conditions, it is not necessary to measure the storage value and its embedded optionality characteristics.

Issue #3: Does MH apply proper accounting treatment to its long-term sales contracts consistent with Generally Accepted Accounting Principles (GAAP)?

MTM is applied to measure both economic value of long-term sales contracts and comply with GAAP addressing derivative accounting.

In general, contracts for future purchase or delivery of an energy commodity will be considered a derivative unless the contracts qualify for the "normal purchase and

[22] *MH develops its long-term price forecasts based on market forecasts purchased from the following five consultants: Global Energy Decisions, PIRA Energy Group, ICF Consulting, PA Consulting and ZE PowerGroup.*

sale" exemption. If a contract is considered an energy derivative contract, then MTM of the contract should be used and the change in fair value should be recognized for financial reporting purposes. If the contract is a purchase and sale in the normal course of business, the contract would qualify for the "normal purchase and sale exemption" and would not be valued at fair value for external financial reporting purposes.

Based on our review of MH's audited Consolidated Financial Statements for the Year Ended March 31, 2009, the sale of energy under long-term contracts are in accordance with MH's expected normal purchases and sales, and are therefore not required to be carried at fair value for financial reporting purposes. This is disclosed in note 1(n) of MH's Consolidated Financial Statements for the Year Ended March 31, 2009 as follows:

Note 1(n) – Derivatives

> *The Corporation does not engage in derivative trading or speculative activities. All derivative instruments are carried at fair value on the consolidated balance sheet with the exception of those that were entered into for the purpose of physical receipt or delivery in accordance with the Corporation's expected normal purchases and sales. Changes in the fair value of derivatives that are not designated in a hedging relationship and do not qualify for the normal purchase and sale exemption are recorded in net income.*

Accordingly, all derivatives which are not in the expected normal purchase and sale of MH would be carried at fair value, and the changes in fair value which are not designated in a hedging relationship would be measured and recorded in net income.

MH's sale of energy under long-term contracts for the future delivery of energy are considered derivative contracts which qualifies for "normal purchase and sale" exemption. Accordingly, the long-term contracts are not required to be measured and carried at fair value for financial reporting purposes.

Based on the audit opinion provided by the external auditors, Ernst & Young LLP, the financial reporting requirements of MH as reflected in the Consolidated Financial Statements for the Fiscal Years Ended March 31, 2007, March 31, 2008, and March 31, 2009 are in accordance with Canadian generally accepted accounting principles and MH has complied with its obligations with respect to the measurement and financial reporting of its long-term contracts and derivatives.

6.5.1.3 Conclusions and Recommendations

- MH should consider applying MTM initially to its open short-term commodity positions and thereafter to its long-term contracts.

  There are challenges to marking to market a portfolio of assets and long-term contracts, where there is no intention to liquidate in the short-term, no intention to transact to capture changes in value, or where market illiquidity would make it difficult to value a position. It is primarily for this reason that while MTM represents leading practice for energy market participants, some entities do not MTM the value of their physical assets (e.g., power plants) or the value of their long-term contracts.

  If MH were to MTM its long-term export contracts, it would require forward price curves for the pricing nodes in these contracts. Developing such forward price curves will require resources for proprietary modeling and analysis. MH could rely on a third-party forward price curves but would need to validate third-party curves in same manner as it would validate internally developed forward price curves.

  Long-term contracts should be viewed as asset positions in MH's overall portfolio. If MH elected to MTM its long-term contracts, hedging opportunities could be identified and portfolio optimization could be facilitated.

6.5.2 Risk Analytics

Risk analytics represent a suite of quantitative tools used to measure various market risk exposures related to commodity trading activities. The purpose of risk analytics are twofold: 1) quantify uncertainty as an attempt to identify probable future mark-to-market movements on the current portfolio, and 2) test model accuracy by ensuring assumptions and inputs (e.g., volatility and liquidity parameters, and MTM) to provide reasonable assurance that model outputs are reliable.

Risk analytics generally used in the energy industry include the following:

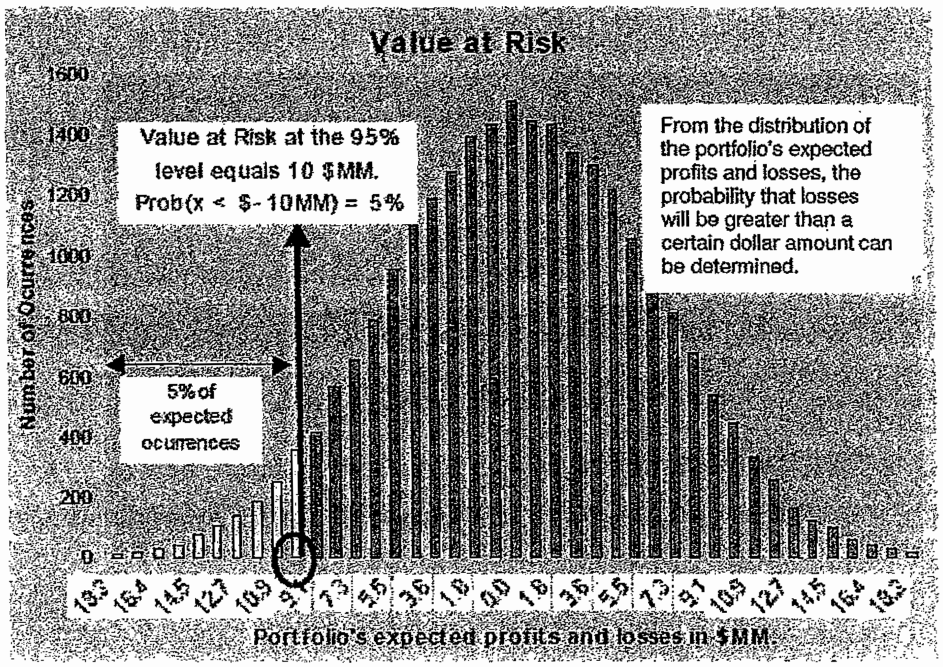
- Value at Risk
- stress tests
- backtests

Value at Risk

Value at Risk (VAR) is a method of measuring risk that captures in a single number, how much money an organization can lose under **normal** market conditions for a particular **horizon** (i.e., time period) and for a given confidence level (i.e., probability). VAR has increasingly become a standard risk management tool, providing quantification of the primary risk exposures an organization faces. VAR can provide critical insight to senior management, traders, shareholders, auditors, rating agencies, and regulators regarding a company's overall portfolio risk.

Exhibit 6-3 below graphically depicts the VAR concept:

Exhibit 6-3: Illustrative VAR distribution curve



In Exhibit 6-3, the probabilistic changes in a organization's hypothetical portfolio value due to a change in various market factors affecting the portfolio value over a one day period are graphed on the x-axis. At the 95% confidence level, the expected change in portfolio value over the next day is estimated at $10 MM. VAR for the portfolio, at a 95% confidence level over the one day time period is therefore $10MM. Stated differently, this means that there is only a 5% chance that the organization's portfolio could lose more than $10MM over the next one day period. (Note: the above example is for illustrative purposes only).

There are three main VAR methodologies simulating changes in the market factors affecting the portfolio being analyzed and in terms of their method of transposing a simulated change in market factors into a simulated change in portfolio value:

- variance-covariance (also known as analytic VAR)
- historical simulation and
- Monte Carlo simulation.

There is no one "right" methodology and each methodology has its own advantages and disadvantages.

Analytic VAR is based on analyzing volatilities and correlations between the different risk exposures of the portfolio. Every instrument in the portfolio being analyzed needs to be expressed as a collection of cash flows in order to derive a "synthetic" portfolio or a cash flow map to study the organization's risk exposures. For a specified time horizon, changes in each cash flow stream individually, and correlated to the other cash flow streams in the portfolio are simulated as a result of simulated changes in the various market risk factors that can affect the portfolio cash flows. These cash flow changes are aggregated into a total portfolio cash flow change probability distribution from which VAR at the desired confidence level can be estimated.

Historical simulation re-values the portfolio being analyzed based on several hundred historical scenarios of past market factors that affect portfolio value to build a "hypothetical" distribution of changes in portfolio value. This hypothetical distribution of portfolio values can then be used to calculate VAR at the desired confidence level. Historical simulation assumes that past portfolio behavior is a reasonable proxy for future portfolio behavior. This assumption can be hard to justify in the fairly nascent energy markets because of the limited availability of historical data and the evolving energy markets (e.g., planned expansion in capacity).

Monte Carlo simulation uses statistical parameters such as volatility and correlation derived from past time series of past changes in market factors to simulate future changes in these market factors. These simulated future market factors are used to generate random scenarios of portfolio value under each scenario. With enough scenarios, a full distribution of simulated portfolio values can be generated from which to estimate VAR. Monte Carlo simulation has an advantage over analytic VAR in that portfolio returns are not assumed to be normally distributed allowing for portfolio characteristics to include non linearity and optionality. On the other hand, Monte Carlo VAR is more computationally intensive due to the number of simulations and statistical parameters required.

Stress tests

Stress testing is another form of measuring price risk. Stress tests are scenario exercises to determine financial losses that might occur under **unlikely but plausible** circumstances. Traditional stress testing is conducted on a stand-alone basis and the stress test results are highly subjective because they depend on scenarios chosen by the stress tester. As a result, the value of stress testing depends on scenario choice and skill of the modeler. A related problem is that stress tests results are difficult to interpret because the scenarios are not probabilistic. Another challenge with stress tests is that stress test procedures are difficult to backtest (See Backtest below for further details). Hypothetical stress scenarios cannot be "validated" based on actual market events. In other words, even when the events specified in a hypothetical scenario actually occurs, there is usually no way to apply what was "right" and "wrong" in the scenario to other hypothetical scenarios to improve them.

Stress tests provide information about an organization's risk exposure that VAR methods can miss. VAR measures risks in the normal course of business and measures the maximum loss expected at a given confidence level over a given holding period but not the expected loss under extreme (i.e., fat tail) market conditions. Thus VAR and stress testing are complementary methods; taken together, VAR and stress tests can provide insight over the full probability distribution of portfolio value changes.

In order to achieve an integrated stress-VAR calculation, hypothetical high loss scenarios with assigned probabilities are added to the appropriate VAR number. Integrating probabilistic stress scenarios into the VAR model helps fill in "risk holes" and adds rigor to the risk measurement process.

Backtests

Backtesting is the comparison of actual transaction risk measure with model-predicted risk measure. If the comparison is close enough, the backtest raises no modeling issues. However, in some cases, the comparison uncovers sufficient variances that raise questions on modeling assumptions.

There is no industry standard on a single backtesting methodology. However, the Basel Committee on Banking Supervision has outlined a framework that attempts to strike a balance between recognized limitations of backtesting and the need for a mechanism to calibrate risk measurement models.

This section addresses the following risk analytic issues:

- *Should a VAR-based method be considered to measure drought risk?*
- *Is the current stress testing methodology reasonable?*
- *Should backtesting be performed to calibrate and validate model assumption?*

6.5.2.1 Leading Practices

KPMG considered the following leading practices in assessing MH's risk analytics:

VAR Models

- VAR *"provides a measurement technique to estimate risk of positions, financial assets, and transactions and intended to predict the potential future range in the MTM value of the forward portfolio, not future realized losses". (Source: "CCRO Valuations Whitepaper," November 2002, Vol. 3, pg. 10.)*

- *"The 'basic' level of exposure measurement is the ability to calculate a value-at-risk (VAR) type measure on a portfolio of transactions. This allows companies to at least obtain a basic quantification of market risk." (Source: "How to be top of the class", Energy Risk Magazine, August 2003, Vol. 8, No. 5, Brett Humphreys, pg. 1.)*

Stress Tests

A firm should be able to:

- *"regularly stress test all or parts of the firm's portfolio to estimate potential economic losses in a range of market conditions including abnormal markets. Corporate level stress test results should be discussed regularly by risk monitors, senior management and risk takers, and should guide the firm's risk appetite (for example, stress tests may lead to discussions on how best to unwind or hedge a position), and influence the internal capital allocation process and...*

- *regularly back test realized results against internal model generated market risk measures in order to evaluate and assess its accuracy. For example, a firm should keep a database of daily risk measures such as VAR...and use these to back test predicted profit and loss against actual profit and loss for all trading desks and business units, and monitor the number of exceptions from agreed confidence bands." (Source: "Senior Management Arrangements, Systems and Controls", FSA Handbook, Release 065, May 2007, Section 16.1.10, pp. 4 -5.)*

Backtests

- *"...when a model has been in use for a reasonable period of time, its results are tested against actual outcomes."* *(Source: "OCC Bulletin 2000-16, Risk Modeling and Model Validation", Office of the Comptroller of the Currency Bulletin, May 2000, pg. 6.)*

- The Basel Committee on Banking Supervision has issued the following suggested guidelines regarding a backtesting framework:

  - *"...develop the capability to perform backtests using hypothetical and actual trading outcomes."*

  - *perform "formal testing and accounting of exceptions on a quarterly basis using the most recent twelve months of data."*

  - *develop a three zone approach to classify backtest results, "distinguished by colours into a hierarchy of responses." The green zone corresponds to backtesting results that do not themselves suggest a model problem. The yellow zone raises model questions but are not conclusive. The red zone indicates a fundamental problem with the organization's model. (Source: "Supervisory Framework for the Use of 'Backtesting' in Conjunction with the Internal Models Approach to Market Risk Capital Requirements", Basel Committee on Banking Supervision, January 1996, pp. 6-7.)*

6.5.2.2 Analysis

Issue #1: Should a VAR-based method be considered to measure drought risk?

KPMG recognizes that VAR is a not a widely adopted measure by many utilities which is supported by the case studies of other electric utilities. Three of the utilities in KPMG's case studies explicitly stated that they did not use VAR as they do not view it is a relevant metric for their business. One utility cited that it does not use VAR as it is unable to liquidate an unknown commodity, and thus does not view it as a relevant metric. Another stated that it is a net short utility, and thus it is not a useful metric in its analysis.

However, there are relevant variations to VAR such as Earnings at Risk, Budget at Risk, Profit at Risk and Revenue at Risk that can have meaningful application to a utility model. For example, Bonneville Power Administration (BPA) calculates a Budget at Risk in order to monitor any impairment to its ability to pay the US Treasury on its outstanding debt in a given fiscal year. Many utilities acknowledge these VAR-based measures have potential application and are exploring these options to measure their market exposures associated with their energy positions.

A VAR-based measure is an alternative approach to measuring revenue exposure in the event of a drought but as with any modeling exercise, the outputs are a function of the underlying assumptions. KPMG recognizes that a VAR-based measure is a complex endeavor for a hydroelectric utility such as MH due to the operational complexities associated with managing water volumes. If MH was to consider implementing a VAR-based drought risk measure, key input data issues include:

- limited historical MISO pricing data (i.e., MISO launched DA and RT energy markets in March 2005);
- the historical worst case drought periods occurred prior to any extensive pricing data for MISO or MAPP; and
- the assumption that MH's asset portfolio remains constant over a five year holding period (a five year holding period is assumed based on the duration of the worst drought on record) arising from any VAR-based model's requirement for a static portfolio over the holding period.[23]

Issue #2: Is the current stress testing methodology reasonable?

In its 2007 Corporate Risk Management Report, MH defined its drought exposure equivalent to the cost of a repeat of the worst drought on historical record in the range of $2.2 to $2.5 billion. MH also quantified the financial impact of a one-year drought, similar to the worst year on record, occurring during the fiscal year ending 2008/09 as being in the order of $600 million.

MH has not assigned a probability to a drought period equivalent to 1937 – 1941, but views a drought event as high likelihood. As a result, MH may have adopted a conservative view in defining an extreme drought by selecting the period from 1937 – 1941 (the worst drought in historical record) as its scenario criteria for an extreme drought period. A detailed description of MH's stress testing calculation is presented in Chapter 4 Power Sales Management.

---

[23] *A five year holding period is assumed based on MH's current drought exposure analysis is based on a five year drought event. Utilities who have adopted a VAR-based measure assume a one year holding period so they can analyze financial exposures associated with the prevailing fiscal year.*

Because drought frequency and flow volumes can be observed in the historical record, probabilities can be developed in an objective manner. In a document filed during the course of MH's 2008 General Rate Application, MH estimated that a five-year drought might occur once every 50 years, based on the historical record.[24] Current assumptions on pricing, however, are subjective and not statistically derived. Thus, the stress test uses three discrete price forecasts (i.e., "high", "expected", "low") for both power and natural gas to develop three drought risk scenarios. To the extent that MH adopts a probabilistic approach (i.e., VAR-based measure) to measuring its drought risk, a single, integrated VAR-stress test can provides MH with an alternative estimate of its drought exposure.

As discussed in Chapter 2, equity is being set aside by MH to act as a buffer against an extreme drought event. MH's methodology is conservative and is consistent with how stress tests are performed by other utilities. Due to the conservative nature of MH's stress test scenario, the methodology appears reasonable.

While there is no industry consensus regarding stress test methodology, prevalent practices suggest stress tests represent "extreme" scenarios rather than catastrophic events. In fact, most banks with strict capital requirements calculate value-at-risk and economic capital thresholds using a two (95% confidence) or three (99%) standard deviation test rather than a doomsday scenario.

Organizations typically address catastrophic events through periodic and highly targeted brainstorming sessions where these events are inventoried and reviewed to determine what management action will be required.

Issue #3: Should backtesting be performed to calibrate and validate model assumptions?

As described in Chapter 3, MH personnel who operate the decision support models (i.e., HERMES, SPLASH, PRISM) are continually validating the models to reflect MH's system performance. The models are not independently validated using backtesting or alternative methodology to document validation results. Currently, only the select MH personnel who have a proficient understanding of the model logic and assumptions are conducting model verifications. As such MH is relying on the expertise and continued availability of these MH personnel in ensuring that MH models are kept up to date and appropriately calibrated, etc. (Please refer to Chapter 3 for a detailed discussion on MH models).

---

[24] *Source: Interrogatory Response: Coalition/MH 1-43, 2007 12 07.*

6.5.2.3 Recommendations

- MH should consider assigning probabilities to its drought stress scenarios in order to have an improved understanding of the financial losses associated with a likely extreme event. Should MH management act on its traditional stress test results? The answer is not definitive.

  MH calculates stressed loss numbers using stress tests and exercises professional judgment to develop associated risk management targets (e.g., a $2.5 billion retained earnings). However, this approach raises the potential risk that the corporation will develop remediation plans based on very unlikely scenarios. Assigning probabilities to the scenarios used in stress tests and incorporating these tests into a VAR-framework would provide MH with a better understanding of potential events' relative probabilities. In particular, a VAR framework allows consideration of impact and probability of other event combinations. As a result, MH should gain a better understanding of the full distribution of potential earnings outcomes. For example, MH would then be able to quantify a risk that, under a scenario of high electricity and/or natural gas prices, a drought of lesser magnitude would result in similar earnings variability.

- MH should consider developing a VAR-based method (e.g., Profit at Risk, Earnings at Risk, Revenue at Risk) to measure its drought exposure.

  Adopting a probabilistic approach to calculating drought exposure can provide MH additional information on retained earnings volatility and provide additional input for arriving at an optimal capital structure. In considering this recommendation, MH should consider the input data issues discussed in Section 6.5.2.2.

- MH should consider incorporating independent backtesting practices to validate internal market risk models.

  Backtesting should be applied to all models, current and prospective (e.g., VAR and long-term contract pricing models) and performed by a function independent of the front office (e.g., Middle Office).

6.5.3 Credit Risk Management

Credit risk management is the process of assessing, measuring, controlling and reporting credit exposures associated with a company's commodity transactions. Credit risk management combines professional judgment and mechanistic techniques to analyze, monitor, and report the credit exposures at both the counterparty and portfolio level.

Credit risk management attempts to mitigate total credit exposure and its components in the event of counterparty default.

Default covers a variety of scenarios (i.e., credit events)[25] including, but not limited to, the following:

- bankruptcy;
- insolvency;
- credit downgrade;
- contractual disputes;
- inadequate quality and untimely commodity deliveries;
- grace period defaults; and
- omitted, partial or delinquent payments.

Total credit exposure is comprised of the following two exposure types:

- Current Exposure
  - Replacement Cost (i.e., MTM)
  - Settlement Exposure
  - Pre-settlement
  - Settlement
- Potential Exposure.

A brief description of each credit exposure type is provided below.

Current exposure is the estimated financial loss that a company would incur if a given counterparty failed to perform its obligation under a given contract(s) today.

[25] *A credit event is material, objectively measurable and publicly disclosed.*

The current exposure amount is the sum of replacement cost and settlement exposure (net of any collateral held (in present value dollars).

Replacement cost or MTM is the unrealized **gain**[26] associated with an open contract's fair value. If a counterparty fails to perform, the company is required to purchase energy at current market prices greater than the contract price incurring credit losses. Alternatively, if the purchaser of an in-the-money power sale contract defaults, the seller must find a replacement purchaser at current market prices that are lower than the contract price.

Settlement exposure is the risk that a counterparty defaults subsequent to the company performing its obligation. Settlement exposure is comprised of two sub-components – pre-settlement risk (i.e., unbilled receivables); and settlement risk (billed receivables).

Potential exposure represents the measure of the potential change in credit exposure based on expected fluctuations in market prices (i.e., price volatility of the underlying commodity) over a given time horizon. Potential Exposure is equal to the Current Exposure plus a statistical estimate of expected changes in underlying commodity prices affecting the contract's fair value.

Varying methodologies are currently used to calculate potential exposure, most notably:

- Value-at-Risk (i.e., Credit Value-at-Risk)
- Stress Testing
- Scenario Analysis

Credit Value-at-Risk ("CVAR") and its various models are complex analytic tools to determine the portfolio's or counterparty's maximum credit exposure in "normal" market conditions over a given time period within a specified probability (i.e., confidence interval).

In general, Potential Exposure involves using historical data on market prices, volatility, correlation and interest rates, the current portfolio positions, and pricing models (e.g., option models) to determine fair market values for those positions. These inputs are then combined in different ways, depending on the method, to derive an estimate of a particular percentile of the distribution, typically between the

[26] *MH's current exposure related to future commodity deliveries is limited to contracts where the contracted price of commodity is favourable to the market price (i.e., in-the-money). Current exposure is zero when mark-to-market values are negative.*

95^{th} and 99^{th} percentile and an assumed holding period (i.e., the time it takes to liquidate the positions in the portfolio).

Total Exposure represents the maximum financial loss a company stands to lose assuming no recovery is collected when a counterparty defaults on its obligations **(i.e., worst case scenario)**. Total exposure is calculated as the sum of two components – current; and potential exposure less any collateral held as represented in the Equation 1.0 below.

Equation 1.0: Total Credit Exposure

Total Exposure = [(MTM+A/R+CVAR) – (Net Collateral Held)]

This section addresses the following credit risk management issue:

- *Does MH measure credit exposure in a manner consistent with leading practices?*

6.5.3.1 Leading Practices

KPMG applied the following leading practices in assessing MH's credit risk measurement practices:

- *"Position replacement cost and collateral values should be measured both at market and estimated liquidation value." (Source: "Toward Greater Financial Stability: A Private Sector Perspective", The Report of the Counterparty Risk Management Policy Group II, July 2005, p.58.)*

- *"Exposure reporting and monitoring should cover all activities with a counterparty. At a minimum, accounts receivable, MTM, and accounts payable should be monitored on a daily basis." (Source: "CCRO Credit Risk Management Whitepaper," November 2002, Vol. 4, pg. 18.)*

6.5.3.2 Analysis

Issue #1: Does MH measure credit exposure in a manner consistent with leading practices?

Based on a review of a MH credit exposure report dated December 31, 2006, it appears that MH measures counterparty credit exposure on an accounts receivable basis only. MH adjusts its receivables exposure by the long-term average default probabilities as provided by Moody's and S&P. The resulting adjusted exposure is a close proxy to calculating expected losses.

Moody's and S&P default probabilities however vary based on time to default. In other words, using long-term default probabilities to adjust 30 day receivables may not always be a reasonable assumption. This practice overestimates MH's expected losses since long-term default probabilities are higher than short-term default probabilities. If MH wishes to adjust its receivables exposure by default probabilities, the time associated with outstanding receivables must closely match the time to default probabilities (i.e., essentially zero for 30 day receivables) corresponding to the respective credit rating.

Currently, measuring replacement cost using MTM valuation principles is limited to transactions under an ISDA agreement (i.e., financial transactions only). Replacement cost for physical transactions is not measured, and doing so would provide a more complete picture of potential future revenue losses in the event of counterparty default.

Based on a June 30, 2009 MH credit exposure report, the peak exposure during the quarter was $53.3 million CAD relative to $146.6 million CAD in total export sales (or 36% of total export sales). This percentage represents a third of total export sales and MH should note that it represents their **minimum** exposure since replacement costs are likely to increase total credit exposure.

Although replacement cost is not measured, MH monitors and measures counterparty exposure in a manner consistent with its transaction volume, complexity and sophistication. In addition, the majority of MH's credit risk management practices are consistent with other utilities who do not engage in speculative trading activities.

6.5.3.3 Recommendations

- MH's practice of adjusting its A/R exposure by long-term default probabilities is a conservative practice in estimating expected losses. Further, MH should consider augmenting its credit exposure calculations by incorporating MTM and Potential Exposure.

- Long-term export contracts expose MH to the greatest amount of potential credit risk rather than short-term opportunity, merchant and financial transactions. MH should consider investing more effort in measuring this exposure in order to develop appropriate risk mitigation strategies in a proactive manner.

6.6 Risk Control

Risk control is a set of tools to manage risks associated with energy transacting activities in a prudent manner. It is an important distinction to understand that risk controls do not reduce risk. Instead, controls represent how much risk an organization is willing to accept. Controls are a direct reflection of a company's risk tolerance defined as the "acceptable level of variation relative to achievement of a specific objective." *(As defined by COSO's Enterprise Risk Management – Integrated Framework, September 2004).*

This section assesses two common risk controls:

- risk limits; and
- transaction processing controls.

Risk limits are designed to manage the magnitude of variance in market and credit exposure. Transaction processing controls are designed to manage the magnitude of variance in operational costs associated with human error.

6.6.1 Risk Limits

The limits placed over market and credit risk are one of the most fundamental controls over an organization's trading and marketing activities. Organizations should establish limits for risks that relate to their risk measures (e.g., mark-to-market, value-at-risk, etc.) which are consistent with maximum exposures authorized by senior management and the board of directors. The established limit structure should apply to all risks arising from an organization's commodity trading and marketing activities.

Risk limits serve as the internal control mechanism over the market and credit risks associated with an organization's trading and marketing activities. Risk limits are dollar denominated or volume based values that: define boundaries of permissible trading activities; and, restrict unauthorized trading activities based on senior management's risk tolerances.

The purpose of a risk limit structure is to:

- mitigate large losses associated with adverse market movements;
- limit exposure to unrealized market and credit losses;

- ensure consistency between trading activity and strategic business objectives;

- promote the development of a diversified and controlled portfolio;

- allocate risk capital on a risk-adjusted basis;

- facilitate the evaluation of financial exposures against corporate risk tolerances; and

- empower an organization to engage in commodity trading and marketing activities within a pre-defined set of guidelines.

A conventional risk limit structure consists of: (1) market limits and, 2) credit limits. Market limits mitigate exposure to downside risk resulting from adverse market volatility and adverse price movements. Market limits typically include dollar stop-loss limits, VAR limits, position limits, trader limits, tenor limits and option limits. Credit limits mitigate potential losses from counterparty default. Credit limits are trade limits placed on counterparty activity. Credit limits are measured against current exposure, potential exposure and settlement risk exposure (see Section 6.5.3 for further detail).

This section addresses the following risk limit issue:

- *Does MH have appropriate market risk limits commensurate with PS&O "Power Related Transactions"?*

6.6.1.1 Leading Practices

KPMG applied the following standards in assessing MH's market and credit risk limit structure:

The limit structure represents maximum exposures authorized by senior management and the board of directors. Limit types should include:

- *volume limits, trader limits, stop-loss limits, VAR limits, and authority limits, position limits, tenor limits;*

- *liquidity limits (i.e., bid-ask spreads) to prohibit trading in illiquid instruments or geographies;*

- *limits reflecting stress testing and scenario analysis results; and*

- *the limit structure should include a reference to an "Authorization to Transact" appendix that specifically defines the authorized instruments, commodities, geographic regions, types and markets and tenors.*

(Source: "CCRO - Guidelines on Establishing a Risk Management Framework and Policy", February 2005, pp. 13-14.)

6.6.1.2 Analysis

Issue #1: Does MH have appropriate market risk limits commensurate with PS&O "Power Related Transactions"?

MH has specified risk limits in the MCP that are limited to the following "Power Related Transactions" activities:

- merchant transactions (Related or Pure Merchant)[27];and
- customer credit.

Merchant Transaction Limits

A summary of the Merchant Transactions limits (Quantitative and Qualitative) are highlighted in Exhibit 6-4. MH has also authorized "System Transactions" which are defined as *"system resources either owned by MH or those procured to meet its load obligations. When economic, System Transactions also include power purchase transactions to serve MH's export obligations, intended to be supplied by MH system resources. System Transactions include both energy and financial products. System Energy Products provide a physical supply while System Financial Products must be associated with an underlying physical position. System Financial Products are used to financially settle price for power related transactions or to manage risk on physical supply." (Source: MCP Schedule "A" dated Oct. 5, 2007).*

We note that risk limits have not been specified for System Transactions.

---

[27] *Related Merchant Transactions involve the resale of power purchased from third parties, and which either flows over transmission owned or reserved by/for Manitoba Hydro, or was purchased for Manitoba Hydro system requirements and has subsequently been deemed surplus.*

Pure Merchant Transactions involve the purchase of power by Manitoba Hydro from one or more parties for resale to one or more parties.

Exhibit 6-4: Summary of Merchant Transaction Risk Limits

Quantitative Limits

Summary of Merchant Transaction Limits			
Limit Type	**Related Merchant**	**Pure Merchant (3)**	**Leading Practice**
Stop Loss	$250,000 (1)	$500,000	Yes
Option Greeks (2)	NA	NA	Yes
VaR	NA	NA	Yes

(1) This stop loss limit has been proposed by PS&O to the PSOMC in a memo dated Jan. 30, 2009. Currently, a stop loss limit has not been specified for Related Merchant transactions.

(2) Greek limits mitigate exposures to adverse movements in options value given a movement in the price of the underlying asset (Delta); rate of change in price of the underlying asset (Gamma); price volatility of the underlying asset (Vega); and time to expiry (Theta).

(3) No Pure Merchant transactions have occurred from 2005 through Jan. 2010. Per the PS&O Division Manager, there are no intentions to engage in Merchant Transactions in the immediate future.

Qualitative Limits

Summary of Merchant Transaction Limits			
Limit Type	**Related Merchant**	**Pure Merchant**	**Leading Practice**
Volume	800 MWh (1)	NA	Yes
Net Position	0 GWh (1)	NA	Yes
Tenor	3 days	3 days	Yes

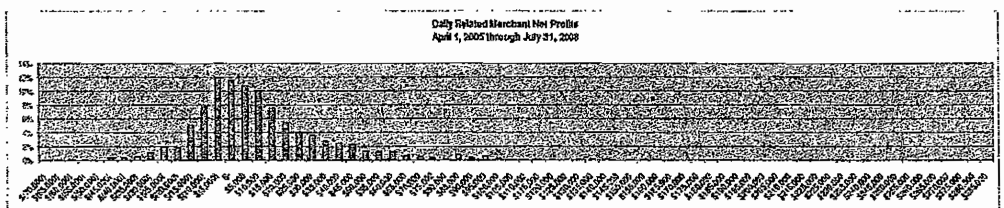
(1) The MCP does not specify a volume limit and specifies a net position limit of 1,000 GWh. In a memo dated Jan. 30, 2009, PS&O has proposed to the PSOMC new volume and net position limits.

In addition to the market risk limits summarized above, MH has established the following trading parameters:

- Fixed price to fixed price transactions may be entered into only if there is a positive profit margin.
- All merchant transactions shall have a maximum duration of six months.[28]
- All transactions must have a positive expected value.
- Long-term wholesale power transactions shall not result in MH's forecast peak or firm energy demand contravening the documented capacity criteria during the contract term.

MH's market risk limits apply to its relatively low risk merchant activities. Based on a historical analysis (performed by PS&O) of the risk exposure for Related Merchant Transactions, net profits totalled $10.6 million since April 1, 2005. The profits represent a return of 58% on total transmission investment over the period. In Exhibit 6-5, the distribution of daily returns is characterized by many small positive returns and infrequent, yet extremely large returns. The maximum daily loss has been $70,000 and the maximum daily profit has been $285,000. The average trading volume has been approximately 2,400 MWh / day or 100 MW / day.

Exhibit 6-5: Daily Related Merchant Net Profits (April 2005 to July 2008)



Percentiles	0%	5%	10%	15%	20%	25%	30%	35%	40%	45%	50%	55%	60%	65%	70%	75%	80%	85%	90%	95%	100%
	$ (69,750)	$ (25,440)	$ (15,770)	$ (12,395)	$ (9,335)	$ (7,255)	$ (5,430)	$ (3,595)	$ (1,412)	$ 1,097	$ 3,265	$ 5,571	$ 7,092	$ 10,443	$ 14,248	$ 18,337	$ 24,166	$ 31,648	$ 40,581	$ 59,157	$ 285,897

Count	1216
Mean	$ 5,023
Standard Deviation	$ 28,955

Source: PS&O Memo to PSOMC dated Jan. 30, 2009 titled "Related Merchant Transactions – Trading Volume Limits and Associated Amendments."

Despite the relative low risk of Related Merchant Transactions, MH recognizes that it is still exposed to significant losses under certain circumstances. A worst case scenario was performed using 800 MWh / day (maximum volume limit) under unfavourable Ontario – MISO price spreads for a three hour period. VAR under 95% and 99% confidence intervals were calculated at $92,579 and $159,122, respectively.

[28] *Under normal water flow conditions, the tenor limit is three days. Under drought conditions, the tenor limit is six months.*

Based on PS&O's historical performance analysis of its Related Merchant trading, the proposed Stop Loss limit of $250,000 appears reasonable. MH's limit structure does not appear to have a VAR limit defined. Additionally, somewhat less importantly, Options limits are also not defined. MH's option transaction volumes are limited to hedging physical natural gas purchases, which are executed in drought periods only. However, to the extent that Options are an authorized product and occasionally executed, MH should consider developing commensurate limits.

Customer Credit Limits

MH's customer credit limit structure is documented in the "Manitoba Hydro Credit Worthiness" dated May 31, 2001. A summary of MH credit limits are highlighted in Exhibit 6-6.

Exhibit 6-6 Summary of MH Credit Limits

Credit Limits

Summary of Credit Limits			
Limit Type	**Merchant**	**System**	**Leading Practice**
Counterparty	Yes	Yes	Yes
Receivables	Yes	Yes	Yes
MTM	No	No	Yes
Current Exposure	No	No	Yes (1)
Potential Exposure	No	No	Yes (2)
Concentration	No	No	Yes (2)

(1) Some companies have established separate A/R and MTM limits to control each exposure type. Separate A/R limits control slow pay or delinquent payment behavior. MTM limits control the replacement cost of in-the-money contracts held by the company.

(2) More sophisticated and larger energy companies have a more comprehensive credit limit structure that include Potential Exposure and Concentration Limits.

As mentioned in Section 6.5.1 Mark-to-Market, MH does not mark its short-term and long-term physical positions. However, as of July 2007, MTM is calculated for three counterparties under ISDA agreements. Based on a MH credit exposure report dated June 30, 2009 there were no transactions outstanding or executed under current ISDA agreements. Aside from the three ISDA agreements, replacement cost is not measured.

In order to provide an understanding of the credit exposure calculation, an example of measuring settlement and MTM exposure against the total counterparty limit is provided in example below.

Example: Counterparty exposures against limits

On March 7, 2010, Utility ABC sells 100 MW, 7 X 24 electricity at $35/MW to Counterparty XYZ for five years with delivery beginning April 1, 2010. An enforceable netting agreement between Utility ABC and Counterparty XYZ exists and Counterparty XYZ has posted a $3,500,000 Letter of Credit ("L/C") issued by a Canadian bank rated "A" by S&P. Counterparty XYZ is rated BBB without the credit enhancement. Based on Counterparty XYZ's net worth and the L/C, it has received an unsecured credit line of $10,000,000 from Utility ABC.

Counterparty XYZ currently has $500,000 in outstanding accounts receivable and net unbilled payables of $365,000 with Utility ABC. On March 8, 2010, the forward curve for 7X24 baseload power is a flat $36/MW for the same five year period. The credit exposure is calculated in the following manner:

Counterparty XYZ Rating	A/R		Prompt Month Sales		Prompt Month Purchases		MTM		Potential Exposure		Collateral Held		Total Exposure	Credit Limit	Available Credit Limit
BBB	(a)	+	[(b)	-	(c)]	+	(b)	+	(c)	-	(d)	=	(e)	(f)	(e) - (g)
	$500,000		$165,000		$515,000		$4,380,000		$3,285,000		$3,500,000		$4,315,000	$10,000,000	$5,685,000

MTM = 100 MW *24 hrs*5yrs*365*(36-35)=$4,380,000

Potential Exposure = $3,285,000*

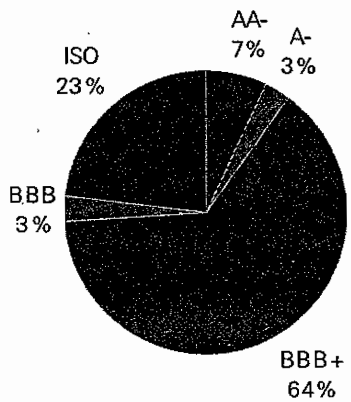
* Assumes 99% confidence interval, one day holding period, and historical volatility of 80%.
An 80% volatility results in an additional $.75/MW price increase to $36.75/MW and resulting MTM of
An 80% volatility is the worst case scenario within the 99% confidence interval.

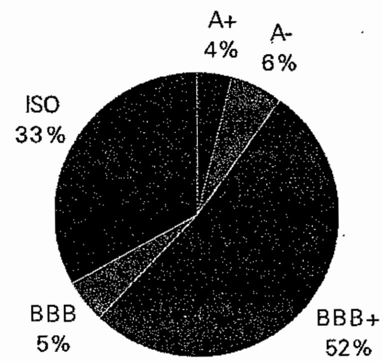
This example is for illustrative purposes only

As the example illustrates, MTM exposure and Potential Exposure can be significant and typically greater than outstanding A/R. In the event a counterparty defaults and MH holds an "in-the-money" short or long-term sales contract (i.e., market prices are lower than sales price), future revenue is adversely impacted. If a counterparty defaults on a long-term export contract, future revenue can be impacted for the period of time it would take to find another creditworthy purchaser.

Another gap in MH's limit structure is the absence of a concentration limit. From December 2006 through June 30, 2009, MH's greatest exposure lies within the BBB credit rating as highlighted in Exhibit 6-7.

Exhibit 6-7: Export Sales by Credit Rating for Quarter ending December 31, 2006 and June 30, 2009





Source: derived from Manitoba Hydro data

6.6.1.3 Recommendations

- MH should consider developing a VAR limit for its Related Merchant Transactions.

  It is apparent that MH has the foundational understanding and analytical capability to implement a VAR limit. Calculating VAR based on actual market prices and comparing it against actual Related Merchant profit and losses may provide meaningful insight into the relative low risk of Related Merchant Transactions. However, MH management should not interpret the VAR calculation as a comparison of potential exposures against a defined limit.

  For a meaningful VAR application, a VAR limit should be developed and compared against MTM gains and losses, not a stop loss limit.

- MH should consider developing Options limits for its options transactions.

  Options limits are not an urgent issue given the transaction activity is limited to drought periods and transaction volumes are minimal. However, options are complex instruments and under volatile market conditions, can add incremental risk rather than hedge it. Since options are an authorized product under the MCP, commensurate limits should exist consistent with MH management risk tolerance.

- MH should consider establishing counterparty concentration limits.

Historically, the probability of counterparty default is very low. However, management should consider establishing concentration limits in order to manage and monitor portfolio concentrations in certain credit ratings (e.g., BBB).

6.6.2 Transaction Processing Controls

Transaction processing controls refer to the operational controls that preserve data integrity throughout the transaction lifecycle. The lifecycle begins with the origination of a physical or financial energy transaction and ends with transaction recording into the accountings system. This lifecycle does not apply to long-term energy sales contracts as they follow a unique set of operational steps and processes (See Chapter 4 Power Sales Management for further detail). The analysis in this section focuses on three predominant transaction types executed by Power Trading:

- Real Time;
- Day Ahead; and
- System Merchant.

PS&O departments are responsible for performing various transactional processes:

- Power Trading is responsible for initiating and executing short-term power trades; and
- Business Services is responsible for confirmations, settlements and accounting.

Each department reports to the PS&O Division Manager. Business Services reports to the PS&O Division Manager in order to provide efficient operational support. In order to preserve segregation of duties, Business Services reports administratively to the Controller.

This section describes MH's transaction lifecycle, together with the transaction processing controls currently in place. Our understanding of controls is based on the controls documented in the WebTrader Summary of Trading Process documents, internal audit reports, and the MCP. A summary of the transaction processing controls at each stage of the lifecycle is included in Exhibit 6-8.

Exhibit 6-8: Summary of Transaction Processing Controls

Pre-Deal Analysis	Deal Execution	Deal Capture	Deal Validation	Confirmations	Settlements & Accounting	Reconciliation

▪ Determination of energy position:
  ▪ Internal analysis
  ▪ Strategy meetings
  ▪ External inputs
▪ Determination of 'value of energy curve':
  ▪ Historical prices
  ▪ Gas prices
  ▪ Internal analysis
▪ Management approvals of:
  ▪ Value of energy curve
  ▪ Trading strategy
  ▪ Bid submissions
	▪ Through pre-negotiated agreements only
	▪ Execution telephone calls recorded for verification
	▪ Each trader has transaction limits and authorities
		▪ Deal entered into webTrader
		  ▪ Verification checks and system limits control inputs
		▪ webTrader tracks any changes made to deals and deal deletions
		▪ Electronic tag is created, includes:
		  ▪ Transmission path
		  ▪ MW volume
		  ▪ Duration
		  ▪ Marketers involved
			▪ Generator and transmission provider approves deal before energy flows
			▪ MH and counterparty monitor IESO dispatch reports for deal tag
			▪ Analysts and traders review all day-ahead deals for accuracy
			▪ Log of counterparty communication maintained
			▪ Conversations with counterparties recorded for verification
				▪ Confirmations sent to non-market counterparties weekly
				▪ Confirmation of deal terms executed on a recorded phone cal prior to execution of written agreement
					▪ Billing Support Officer responsible for daily trading settlements
					▪ Billing Officer responsible for adjustment recording and invoice preparation
					▪ Formal actualization performed by System Control Centre
					  ▪ Ensures energy flowed matches energy scheduled
						▪ Day-ahead decision analyzer balanced to webTrader to ensure all purchases, obligations, etc are captured
						▪ Shadow invoice created to compare to IESO/MISO invoices
						▪ Manual checks of invoices to internal spreadsheets
						▪ Paper contract details matched to webTrader contract details

Pre-Deal Analysis

Pre-deal analysis begins with determining energy positions and prices by Power Trading.

The analytical tools and transaction controls used in this process differ for day-ahead, real-time and merchant trades. There are several aspects of the pre-deal process where risks are mitigated through transactional controls.

Day Ahead Traders monitor energy positions and prices through weekly management meetings, as well as daily trader strategy meetings. Energy positions are determined by analyzing various parameters, including:

- weather forecasts;
- MISO, IESO & Alberta Electric System Operator (AESO) load forecasts;
- MH load forecasts;
- genscape-generation status across Canada and U.S.;
- available transmission;
- water sheets;
- Day Ahead Traders' water optimization spreadsheet;
- the water graph maintained on WebTrader and the EXCEL spreadsheet which projects out one month; and
- the MISO Day II Locational Marginal Pricing (LMP) Tool.

In order to determine the range of prices that are allowable to buy/sell energy in the Day Ahead market, a "value of energy" price curve (i.e., forward curve) indicating the maximum buy price and minimum sell price for each hour is calculated by Power Trading. The curve is developed based on inputs from the following sources:

- MISO market clearing prices from the previous day;
- WebRTO;
- Intercontinental Exchange (ICE);
- Pattern Recognition Technology;

- PROMOD; and
- natural gas prices.

Real Time Traders use a tool known as the Supply and Demand Planner (within WebTrader) to help them balance MH's power supply and demand. This tool calculates the physical capacity position by hour, for up to seven days into the future. The Supply and Demand Planner provides the following information:

- hourly MHEB generation capacity;
- load forecast and load forecast adjustments;
- operating reserves;
- regulating margin;
- actual load, purchases, sales, net transactions, net available resources;
- System Control Centre net MW surplus;
- temperature; and
- existing power deals.

Real Time Traders also review the available transmission and the daily water pricing spreadsheet from the Day Ahead Traders. This analysis allows the Real Time Traders to identify the optimal market (MISO, AESO or IESO) or counterparty.

In order to assess the strategy performance, the Power Trading Supervisor (Real Time Sales) reviews reports from the Real Time desk and the Supply and Demand Planner throughout the day to ensure staff are optimizing the system. In addition, the P&L is monitored daily to determine whether the current strategy is appropriate.

System Merchant Traders use IMO trends, IESO similar day, the bidding strategy spreadsheet, the price pivot spreadsheet and Price Band when making their trading decisions.

For each transaction type, the inputs used in determining the optimization strategies are developed by parties independent from Traders.

Review and approval of key trading reports is the second step. The Power Trading Supervisor (Term Power Sales) reviews various reports for Day Ahead performance, including: P&L Statement, Daily Credit Report, Trade Violations screen, and the Day Ahead Trading Report. Additionally, the value of energy curve is reviewed daily by the PS&O Division Manager.

Deal Execution

MH executes standard Master Agreements and Market Participation Agreements to minimize deal execution risk. Master Agreements govern bilateral power transactions and Market Participation Agreements govern ISO transactions such as MISO and IESO. MH does not undertake transactions with customers who do not have an executed Master Agreement in place.

In order to monitor the trader's activities, deal input is restricted to traders and each trader transacts within their respective individual transaction limits and delegated authorities outlined in the MCP (Approval Authority for System Energy Products). These limits are configured into WebTrader to control unpermitted activities.

As an additional control, all transactions are executed on a recorded telephone line to allow investigations of any transaction discrepancies or counterparty disputes.

Deal Capture and Amendments

During the deal capture and amendment process, WebTrader serves as MH's official system of record. Entering a transaction into WebTrader requires supervisory authorization in addition to checking counterparty credit limits, and the transaction's delivery dates, quantity and term details. An audit trail of any deal changes is captured in WebTrader. Deal modifications in WebTrader [prior to confirmations] can only occur when a reason is entered into the system by authorized front office personnel. Any cancelled / deleted deals appear on the deal summary and violation screen which is reviewed by the Trading Supervisor daily.

Regarding System Merchant Transactions, deals are initially recorded into a spreadsheet (i.e., the profit allocation calculation) and subsequently re-entered into WebTrader. The reason for the dual entry process is that WebTrader does not currently have the system functionality to calculate the profit allocation between Tenaska and MH.[29] Both Internal Audit and PS&O recognize the potential for human error and an initiative to enhance WebTrader is under development by PS&O's Market Process and Technology Department.

[29] *MH has four unique profit sharing agreements with Tenaska. Three are firm transmission positions and the fourth is not. For the three firm contracts, MH will buy power from MISO in the DA (or RT) market via Tenaska and sell power to the IESO in the RT market. The profit on the sale to IESO will be shared in accordance with Tenaska's participation rate. The fourth contract involves RT Trading to try and earn a spread between MISO and IESO markets.*

All physical deals require an electronic "tag" (e-tag) for scheduling purposes. As part of the deal capture process, MH traders monitor the IESO dispatch report every hour to identify deals requiring e-tags. Traders create e-tags in WebTrader's tagging system. E-tags include information on the transmission path, MW volume, duration, marketers involved and any line losses. Power schedules cannot be accepted by the IESO without proper e-tags.

Deal Validation

In order to ensure deals are recorded accurately power trading analysts and day ahead power traders review all DA deals. They also review any deals rejected by MISO to check for the reasonableness of rejection and to ensure that tags are cleared to ensure that power is not released for cancelled deals.

For verification purposes, MH maintains a log of counterparty communication and maintains a record of all phone and chat room conversations with counterparties.

Confirmation

Energy contracts with terms less than two weeks with delivery within the next two weeks do not require a written confirmation. These transactions are executed using either MH's recorded telephone lines or approved on-line electronic trading platforms (e.g., ICE, MISO) using MH equipment.

Transaction confirmations are sent to counterparties who MH has executed physical bilateral and financial transactions (under an ISDA agreement). Transaction provisions to be confirmed by the parties include: transaction term, product, point of delivery, price and quantity.

Settlement and Accounting

Several controls are in place at MH to ensure trades are recorded accurately, including the following:

- The month-end journal entry is reviewed by the Billing Coordinator or Business Services Department Manager prior to being uploaded to SAP (i.e., the General Ledger).

- The Billing Officer runs the WebTrader MISO Settlement Discrepancy Manager to reconcile/isolate any discrepancies between WebTrader and the MISO settlement statement. Any discrepancies are tracked on a dispute tracking spreadsheet.

- During the settlement process, a trader is unable to change any terms or provisions without Billing and Settlement's approval in the system.

- The accounting system places a lock on WebTrader at month-end to ensure no further changes take place during the reconciliation between the data uploaded to the G/L and WebTrader.

- A spreadsheet of PSOMC FTR bid approvals is maintained by Billing and bids are compared to invoices to address any discrepancies.

- The Business Services Manager periodically reviews the FTR bid approval spreadsheet.

- For MISO FTR activities, Billing receives weekly invoices and reconciles these with shadow settlements. The Billing Coordinator compares shadow settlements with invoice before approving the invoice.

MH segregates the daily trading settlement function (Billing Support Officer) and the adjustment recording and invoice preparation functions (Billing Officer). This provides an additional control as the Billing Officer provides an additional check on the work conducted by the Billing Support Officer.

Reconciliations

There are several controls in place to ensure that information has been documented correctly at MH.

- To ensure that all generation resources, power purchases, obligations, etc., have been entered into WebTrader, MH balances the DA Decision Analyzer to WebTrader on a daily basis. This reconciliation is signed off by the Power Trading Supervisor or Department Manager.

- To ensure that accurate billings have been generated, a shadow invoice is created in WebTrader and compared to the final invoice from IESO and MISO.

- The Billing Officer manually compares the Extra-provincial Sales/Purchases Report (from WebTrader) to the balances in SAP.

- MISO invoices are also reconciled to the settlement worksheet and the market net invoice and the administration fee invoice is reconciled to the settlement worksheet.

- Billing manually compares the Excel spreadsheet of PSOMC FTR approvals to actual FTR positions.

- To ensure that correct contract terms are documented, one of the Billing Officers compares the paper contract details to the contract details within WebTrader during its month-end procedures.

The process for reconciliations has been continually advanced since the 2006 review and recommendations for further enhancements are in the recommendations in Section 6.6.3.2.

6.6.3.1 Leading Practices

KPMG considered the following leading practices in assessing transaction controls:

"Before a deal is executed, senior management works with the front office to establish strategies that develop the business in alignment with the risk/reward profile of the company. The front office then executes deals that satisfy that strategy. More complex or long-term deals may require additional structuring or pricing to assess their true value. If a deal is within defined limits and the terms are approved, a contract is put in place. The deal is then executed with the counterparty and the terms are captured in a system. The deal is then assigned to a portfolio for ongoing management over the term of the deal as market conditions change. If a deal requires the movement of a physical commodity, the front office schedules product flow with a transportation provider.

After a deal has been executed and captured, the middle office must independently verify the accuracy of the terms through system reconciliations, third-party confirmations, and risk analytics. These processes serve as key control functions over the deal execution process. The credit and contract administration groups will also monitor the deal over its life, ensuring that contract provisions are maintained and credit risk managed. Once the deal has reached its term and the contract provisions have been satisfied, the back office will settle the deal (i.e., resolve discrepancies and invoice the counterparty) and book the appropriate entry in the financial records." (Source: CCRO Organizational Independence and Governance Working Group, November 19, 2002 pg 16.)

6.6.3.2 Recommendations

MH employs a wide range of control mechanisms throughout the power sales transaction process that provide reasonable assurance that operational risk is managed. Based on KPMG's experience with peer utilities, MH transaction controls are consistent with prevalent practices. In comparison to leading practices, MH would benefit from the following:

- Update documentation regarding FTR settlement and the reconciliation processes to reflect practices currently in place. In reviewing procedural documentation on the FTR process, KPMG observed that the current reconciliation process for FTR has not been updated in the procedural documentation.

- Continue efforts to eliminate the redundant deal entry process related to System Merchant transactions.

- The profit allocation calculation related to System Merchant transactions (i.e., Related Merchant) is performed by the front office. KPMG recommends that the back office verify the profit allocation calculation to ensure P&L performance monitoring is independent.

6.7 Risk Reporting

Risk reports are regularly disseminated throughout an organization to convey exposures and business unit performance to executive management, the risk management committee and the Board of Directors. A meaningful package of risk reports summarizes portfolio positions, market and credit exposures against limits, financial performance and probabilistic risk measurement. Risk reports are typically generated and prepared by an independent function (e.g., middle office) in order to ensure objectivity and accuracy.

Effective risk reports are in a format that can be easily read and understood by executive management and the Board. Leading companies have developed user-friendly reports that present information in a consistent manner.

This section describes our assessment of risk reporting for power sales. A timely, comprehensive suite of risk reports are designed to help management monitor and make informed decisions regarding market, credit, drought and operational exposures.

6.7.1 Adequacy of Risk Reporting

This section addresses both adequacy of existing reports and the productions standards in place at MH as compared to leading practices. In this section we address the following risk reporting issues:

- *Are MH risk reports comprehensive?*
- *Are reports accurate and complete?*
- *Do current variance reports adequately present actual versus forecasted data?*

6.7.1.1 Leading Practices

KPMG considered the following leading practices in assessing MH's risk reporting:

- *"The role of management information should be to help govern a firm's governing body and senior managers to understand risk at a firm-wide level. Doing so should help them determine if the firm is prudently managed with adequate financial resources; make decisions that fall within their ambit (for example, the high level business plans, strategy and risk tolerances of the firm); and oversee the execution of tasks for which they are responsible." (Source: FSA-Senior Management, Arrangements, Systems and Controls-SYSC 14-Prudential risk management and associated systems and controls Section 14.1.47).*

- *"The management information that is provided to a firm's governing body and senior management has the following characteristics:*

  It should be timely, its frequency determined by factors such as: the volatility of the business in which the firm is engaged (that is, the speed at which its risk can change); any time constraints on when action needs to be taken; and the level of risk that the firm is exposed to, compared to its available financial resources and tolerance of risk;

  It should be reliable, having regard to the fact that it may be necessary to sacrifice a degree of accuracy and timeliness; and it should be presented in a manner that highlights any relevant issues on which those undertaking governing functions should focus particular attention." (Source: FSA-Senior Management, Arrangements, Systems and Controls-SYSC 14-Prudential risk management and associated systems and controls Section 14.1.49).

Exhibit 6-9 describes the leading practice regarding power risk reports generated and the frequency of reporting. Leading practices indicate that these reports are originated by the risk management group on a daily and monthly basis. Reports are typically circulated to the Board of Directors, CEO, CFO, CRO (or equivalent), the Risk Management Committee, and Business Unit Leaders, and front line management.

Exhibit 6-9: Leading Practices in Risk Reporting

Leading Practice Reports	Contents
Position Reports	Net position by: - Commodity - Region - Counterparty - Tenor
Financial Performance Reports	Realized and unrealized gains and losses by: - Risk book - Commodity - Trader
VAR Report	Probabilistic market exposures by: - Risk book - Commodity - Trader - Transaction
Exposure vs. Limits Report	Market exposures vs. limits
Limit Violation Report	Limit exceptions with rationale and corrective action
Stress Testing Report	Potential market exposures under extreme market conditions
Credit Exposure Report	Counterparty exposures vs. limits

Source: CCRO, CCRO0-Volume 2 of 6 Governance and Controls November 19, 200 pp. 41-43.

6.7.1.2 Analysis

Issue #1: Are MH's risk reports comprehensive?

Exhibit 6-10 lists the reports currently used at Manitoba Hydro to communicate short and long-term power trading activities. Exhibit 6-10 provides a summary listing of MH's current management reports highlighting each report's:

- summary of contents;
- report origination;
- report recipients; and
- frequency of reporting.

Exhibit 6[illegible]: Summary of Manitoba Hydro Management Repor[illegible]orted by Report Origination)

Summary of Manitoba Hyd[illegible] Risk and Management Reports				
Report Name	**Summary of Contents**	**Report Origination**	**Report Recipient**	**Frequency**
Day Ahead Trading Report	Financial and physical positions for day ahead trades	Power Trading	Power Trading Supervisor	Daily
FTR Position Report	FTR cost vs.revenue	Power Trading	PSO PSOMC	Monthly Monthly
Credit Exposure and Exception Report	Credit exposures and exceptions by counterparty	Export Power Marketing	PSO Management EPRMC (exceptions)	Monthly Monthly
Wholesale Power Transactions Credit Report	Credit exposure Export sales by credit rating	Export Power Marketing	EPRMC	Quarterly
Monthly Middle Office Report (first report issued June 2008)	MISO market conditions Executed ST transactions Surplus energy/forward position Related merchant transactions	Middle Office	EPRMC	Quarterly
Transaction Compliance Report	Policy exceptions	Middle Office	EPRMC	Quarterly
Activities Report	YTD power sales and expenses Portfolio summary	Business Services	PSO Management	Monthly
Export Power Sales and Expenses Report	Export power sales Power purchases Net export revenue	Business Services	PSO Management PSOMC EPRMC	Monthly Quarterly Quarterly
Export Power Sales and Expenses Summary	Summary of export power sales and expenses	Business Services	Corporate Accounting	Monthly
Transaction Performance Report	Opportunity and merchant transactions versus market prices	Business Services	PSO Division Manager EPRMC	Monthly Quarterly
Management Report	Financial data for power purchases and sales	Corporate Accounting	PSO Management Sr. VP Power Supply Executive Committee	Monthly Monthly Monthly
Supply Value at Risk Variance Analysis	IFF variance analysis	Hydraulic Operations	EPRMC	Quarterly
Energy Resource Review and Outlook Report	IFF variance analysis	Hydraulic Operations (input from Bus Svcs)	Executive Committee MH Senior Management	Monthly Monthly
Forecast Generation Costs and Interchange Revenue Report	Year one and two forecast of generation costs, export and import revenue	Hydraulic Operations	PSO Management Planning Review Committee Executive Committee	Annual Annual Annual
Forecast Generation Costs and Interchange Revenue Report	Years three to eleven forecast of generation costs, export and import revenue	Resource Planning and Market Analysis	PS Management Planning Review Committee Executive Committee	Annual Annual Annual

Source: KPMG compiled from Manitoba Hydro data.

The following Exhibit 6-11 compares MH's risk reports to leading practice reports.

Exhibit 6-11: MH's Risk Reports by Leading Practices

Leading Practice Reports	MH Reports
Position Reports	Monthly Middle Office Report Activities Report Day Ahead Trading Report FTR Position Report Energy Resource Review and Outlook
Financial Performance Reports	Export Power Sales and Expenses Transaction Performance Report Management Report Forecast Generation Costs & Interchange Revenue
VAR Report	Not Applicable
Exposure vs. Limits	Does not exist
Limit Violation Report	Credit Exposure and Exception Report
Stress Testing Report	IFF
Credit Exposure Report	Credit Exposure and Exception Report Wholesale Power Transactions Credit Report

Source: KPMG analysis

As seen in Exhibit 6-11, MH reporting is generally consistent with leading practice except in the area of "Exposure vs. Limits" reports. An Exposure vs. Limits report is a key risk report that MH should consider developing to monitor the market exposures related to System Merchant transactions. Since a Stop Loss limit has been proposed for this transaction type, a report to present exposures (i.e., realized gains and losses) vis-à-vis the limit would be helpful for performance and compliance monitoring purposes.

Issue #2: Are risk reports accurate and complete?

Overall, MH quality assurance and controls appear to be sufficient to ensure accurate and complete reports. The reconciliations performed to ensure accurate and complete reports are documented in Section 6.6.2.

Issue #3: Do current variance reports adequately present actual versus forecasted data?

Variance reports are produced to compare actual against forecasted data. Overall, we find that MH prepares variance reports for all of its forecasted data in adequate detail and structure. Our finding is based on an analysis of the following variance reports produced by MH.

- The Preliminary Variance Report - prepared by Hydraulic Operations with input from Business Services. This report compares the annual IFF versus actual revenues. Variances are included for dependable trades, opportunity trades, other revenues, purchase costs, thermal costs, water rental costs and other transmission costs. Business Services is responsible for validating the accuracy of the "actual" numbers through the reconciliation process outlined above. Hydraulics and Business Services coordinate to provide explanations for the variances. This analysis is reviewed by the Division Manager of PS&O and distributed to the Senior Executives, Division Managers and a number of other Managers.

- The Preliminary Variance Report is created annually and describes variances between the annual IFF and actual results. Additionally, it provides the details that were in the preliminary analysis and related to energy in reservoir storage, water supply conditions and energy supply outlook.

- The Monthly Management Report - includes an operating forecast variance analysis, capital forecast variance analysis, revenue and consumption variance analysis and explanation for MH's 25 largest customers.

- A Supply Variance Analysis Report - is created quarterly, or more frequently on an as needed basis (e.g., if there are material changes to the IFF which cause MH to re-forecast its revenue). This report is provided to the EPRMC.

6.7.1.3 Recommendations

MH produces a wide range of risk reports that provide useful information to line managers and the EPRMC. Based on KPMG's experience with power utility reporting processes, this is consistent with prevalent practices. When compared to leading practices, MH provides most of the recommended reports. However, MH would benefit from the following additional risk reports to make its suite of risk reports more comprehensive.

- A report detailing market risk exposures versus limits. Exposure reporting on a daily and monthly basis will allow management to monitor that transaction exposures are within management risk tolerances. Any limit exceptions would be identified and reported to MH senior management and the EPRMC.

- Stress testing reports analyzing MH's portfolio risk exposure under a variety of scenarios. These reports would help with strategic planning, risk capital allocation and portfolio management.

- Additionally, with the exception of the Day Ahead Trading Report, MH does not produce any daily risk reports. MH may benefit from increasing the frequency of risk reporting to help ensure early identification of risk management issues and to keep traders apprised of their individuals positions and limits.

6.8 Conclusion

With respect to power risk management, based on our analysis, we conclude that MH demonstrates prudent risk management with the following risk management practices:

- Extensive corporate oversight and a deliberate internal review process related to major export contract term sheets;
- Conservative stress testing assumptions and methodology;
- Transaction processing controls consistent with prevailing practices to mitigate human error and operational risk;
- Compliance and risk monitoring performed by an independent middle office; and
- Comprehensive suite of management and performance reports.

In light of these prudent practices, MH will continue to strive to keep pace with the dynamic energy markets and will identify opportunities to improve its risk management capabilities. MH may consider the following recommendations:

- Revise long-term contract policies stipulating Middle Office participation in the internal review process of major export contract term sheets;
- Develop formal identification of all significant risks in policies and procedures;
- Measure market risk exposure for short-term physical positions in its trading portfolio and evaluate the benefits associated with valuing its long-term contracts;
- Consider a probabilistic measure (e.g., Revenue-at-Risk) as an alternative tool to further understand potential drought exposure;
- Develop risk limits commensurate with authorized trading activities and products; and
- Develop risk exposure monitoring reports for compliance purposes.

7

7. Conclusions and Recommendations

This Chapter summarizes our conclusions and our key recommendations from the previous chapters, followed by key highlights.

7.1 Conclusions

The utility industry has undergone significant change in the last decade, including deregulation in some jurisdictions, the introduction of competitive energy markets across Canada and the United States, heightened environmental attention, fluctuating economic conditions and a continued focus on security of supply at reasonable prices for ratepayers.

Taken together, these factors have significantly added to the complexity of managing risk. Most utilities are continually adapting their risk management practices to these changing circumstances.

Like its peers, Manitoba Hydro is subject to the impacts of these changes. Accordingly, Manitoba Hydro's operations have become, and will continue to be, more complex than ever before. This will continue to require further advancements in its modeling capabilities, export power sales practices, corporate risk governance, and power risk management practices.

Manitoba Hydro has well established practices in place and a number of initiatives underway to improve its risk management practices. Many of our key findings reflect recommendations Manitoba Hydro should consider in further improving these practices.

- With respect to the modeling approach at Manitoba Hydro, we conclude:
  - Manitoba Hydro has developed a suite of models that capture the key characteristics of the Manitoba Hydro system. These models are used to help optimize system operations and to support long-term capacity planning.
  - We are satisfied that Manitoba Hydro has taken appropriate care and due diligence in developing and maintaining these models and in using them in its operations planning process.

- Manitoba Hydro's current approach to forecasting and to calculating dependable energy appears reasonable and is consistent with practices at other North American hydroelectric utilities. It is reasonable to rely on historical flow data for estimating dependable energy.

■ With respect to long-term contracting for export power sales, it is our opinion that:

  - Manitoba Hydro has made appropriate strategic choices in entering into long-term fixed price contracts for export power sales;

  - Manitoba Hydro has appropriately established the firm export volumes in these contracts; and

  - Manitoba Hydro has an appropriate methodology for arriving at the sales price in such contracts.

  Also, we find that Manitoba Hydro continues to improve its contractual documentation to more effectively mitigate the risk exposure from entering into long-term fixed price contracts for the sale of firm energy.

  On the basis of the policy decisions in place with respect to risk tolerance, Manitoba Hydro quantifies its drought risk appropriately and currently provides for appropriate levels of reserves of risk capital against its projected drought risk.

■ In terms of risk governance, we conclude the following:

  - Manitoba Hydro's power sales are asset backed. These sales are generally low risk and the Manitoba Hydro risk governance policies and reporting relationships, including the role of the Middle Office, are evolving appropriately.

  - The Export Power Middle Office is a single, independent, risk management function. It is steadily progressing in terms of its responsibilities for measuring, monitoring, controlling, and reporting the risks associated with Power Sales and Operation's opportunity power sales activity.

  - The Export Power Middle Office is undertaking an initiative to improve its risk analytics capabilities. It requires further resource(s), supported by risk analytics software that is integrated with Manitoba Hydro's energy transaction management system (WebTrader). The timeliness of this risk monitoring will continue to improve with added analytical resources and related technology.

- With respect to power risk management, we conclude that Manitoba Hydro demonstrates prudent risk management with the following risk management practices:

  - Extensive corporate oversight and a deliberate internal review process related to major export contract term sheets;

  - Conservative stress testing assumptions and methodology;

  - Transaction processing controls consistent with prevailing practices to mitigate human error and operational risk;

  - Compliance and risk monitoring performed by an independent middle office; and

  - Comprehensive suite of management and performance reports.

  Manitoba Hydro should continue to strive to keep pace with the dynamic energy markets and in doing so should consider our recommendations to improve its power risk management practices.

7.2 Recommendations

While we conclude that Manitoba Hydro has well established risk management practices in place and a number of initiatives underway, the following summarizes our key recommendations to further advance and Manitoba Hydro's management of risk. Most of the recommendations relate to generating improved operations management and better documentation. Specifically, Manitoba Hydro should consider the following.

- Enhance the functionality and resourcing of the Export Power Middle Office.

  - Manitoba Hydro should transfer the credit risk function in Power Sales & Operations to the Middle Office. This would further enhance independence and oversight of decisions made in Power Sales and Operations.

  - Manitoba Hydro should also consider the transfer of the market risk function in Power Sales & Operations to the Middle Office. This would further enhance independence and oversight of decisions made in Power Sales and Operations.

- Manitoba Hydro's process of reviewing export contracts and term sheets should include the Middle Office to perform a challenge function.

- Responsibility for power risk management policy for opportunity sales should be consolidated in the Middle Office.

- Manitoba Hydro should consider adding resource(s) including risk analytic tools (i.e., software) to increase the risk analysis capabilities of the Middle Office. The Middle Office should have the necessary core risk assessment and quantification methods and systems to independently assess the risk profile of all opportunity sales transactions.

■ Develop formal identification of all significant risks in policies and procedures.

- In its export contracting process to date, Manitoba Hydro has mitigated its incremental risk by securing firm transmission capacity and expanding import capability. To ensure that similar mitigation strategies are adopted in the future, Manitoba Hydro should consider documenting its risk identification and assessment procedures to institutionalize its existing informal internal review process. This could help validate that all significant risks have been identified and integrated into the risk measurement process and control structure.

■ Enhance the number of risk tolerance limits.

- While Manitoba Hydro has specified risk limits in "Power Related Transactions" and Customer Credit, and has expanded its limit structure by recently establishing Stop Loss Limits, it should consider developing a Value at Risk (VAR)-based limit for Related Merchant Transactions. This may provide a meaningful insight into the relative low risk of Related Merchant Transactions.

- Manitoba Hydro may also consider developing other risk tolerance limits such as options limits and counterparty concentration limits, recognizing that these types of transactions are also relatively low risk.

■ Measure market risk exposure of short-term physical positions and credit risk exposures.

- Manitoba Hydro should consider applying mark-to-market initially to its open short-term commodity positions.

- Manitoba Hydro should also evaluate the benefits for measuring market risk in long-term export contracts which would require resources to develop forward price curves.

- Manitoba Hydro should add an "exposure versus limits" report to its existing suite of risk reports. Exposure reporting on a daily and monthly basis allows monitoring of transaction exposures with risk tolerance levels,

■ Further document how the pricing was arrived at for export contracts and term sheets, as well as document the approvals of term sheets.

  - While the pricing methodology and process is appropriate, Manitoba Hydro would benefit from improving its documentation of pricing as well as term sheet approvals. Manitoba Hydro should clarify the role of the premium applied to long-term contracts, confirm the appropriate magnitude, and document its pricing analysis and its future avoided cost analysis.

  - Manitoba Hydro has a relatively small group of highly skilled analysts and negotiators in power sales with deep experience in long-term export sales contracts, and more formal documentation of the pricing analysis will help preserve that experience.

■ Continue to further improve the HERMES and SPLASH models.

  - Manitoba Hydro should continue with its current initiatives and plans to enhance its models.

  - Manitoba Hydro should better quantify and communicate to stakeholders the impacts of the "perfect foresight" assumption on the calculation of drought costs.

  - Manitoba Hydro should explicitly consider uncertainty in future water flows in the modeling process used to identify optimal production decisions.

■ Conduct more scenario analyses, stress testing and backtesting.

  - Given uncertainty over climate change, Manitoba Hydro may wish to examine the potential impact of changes in water flows from the historical patterns. In particular, Manitoba Hydro may wish to assess the financial impacts of drought events worse than those found in the historical record.

- In its analysis of expansion plans and development sequencing, Manitoba Hydro should consider conducting additional scenario analyses as detailed in Chapter 4 to examine the potential financial impact of drought events on the economics of expansion plans.

- Manitoba Hydro should consider undertaking more stress testing to evaluate risk exposure. Stress testing can help management discussions on risk tolerance levels, risk capital allocation and portfolio management.

- Manitoba Hydro should consider using backtesting to assist in further validating model outputs. Backtesting compares actual risk with model-predicted risks, and helps evaluate model accuracy.

■ Formally document the HERMES and SPLASH models.

  - As HERMES and SPLASH are in-house models and operated by a small group of highly skilled modelers, Manitoba Hydro should provide more formal documentation of the models to preserve their proprietary information and assist new modelers. This will require dedicated additional resources to develop the documentation, but doing so will help mitigate risk in the event of staff turnover.

  - Given ongoing evolution in modeling, Manitoba Hydro should consider formal peer review or benchmarking of the models to benefit from modeling developments elsewhere in the energy sector.

■ Review its capital structure on a regular basis.

  - Manitoba Hydro is planning a major capital expansion to its generation and transmission system. Manitoba Hydro is also in the process of improving its risk management practices. Both of these may affect its optimal capital structure. Accordingly, Manitoba Hydro's capital structure should continue to be formally reviewed on a regular basis.

7.3 Key Highlights

The Consultant has raised serious concerns as to the financial viability of Manitoba Hydro and the risk of major power outages related to its long-term export contracts. Further, the Consultant asserted in 2008 that Manitoba Hydro actions in the previous five years have cost the corporation in the range of $1 billion. Our approach has been to identify and analyze all of the alleged deficiencies in Manitoba Hydro's operations and have done so pursuant to our scope of work as detailed in the main report.

We are of the view that:

- there is no material risk that Manitoba Hydro is facing bankruptcy as a direct consequence of Manitoba Hydro's export sales practices;
- there is no material risk that Manitoba is facing power outages as a direct consequence of Manitoba Hydro's export sales practices;
- Manitoba Hydro's drought management strategies are prudent in the context of a hydro-based generation system;
- there is no evidence to support an assertion of losses approaching $1 billion in the five years cited, based on our analysis of Manitoba Hydro's modeling, export sales contracts and risk management practices;
- Manitoba Hydro has prudently utilized a strategy based on entering into long-term contracts and the securing of transmission rights in the development of its system; and
- Manitoba Hydro has operated in accordance with its legislative mandate.

Overall, in the context of the nature, size and business model of its hydroelectric power operations, we are satisfied that Manitoba Hydro is following sound practices in its use of forecasting models, long-term power sales contracting, risk governance, and power risk management.

KPMG

Manitoba Hydro – External Quality Review

Appendices to the Main Report

April 15, 2010

ADVISORY

AUDIT • TAX • ADVISORY

A

Appendix A: Glossary of terms

2008 Price Forecast	Manitoba Hydro's 2008 Electricity Export Price Forecast for the 2009 to 2040 period
A/P	Accounts Payable
A/R	Accounts Receivable
ACE	ACE Group – insurance provider
AESO	Alberta Electric System Operator
Alternative Base	The quantification of drought risk is represented by the change in the financial position of MH in comparison to the Alterative No Sale financial forecast prepared by MH
ATF	After-the-fact
Back Office	Responsible for supporting the Front Office trading function including financial accounting, hedging and derivatives accounting, customer invoicing and collections, counterparty settlement, contract administration, financial reporting, tax and other regulatory compliance
Basel II	A set of banking recommendations issued by the Basel Committee for Banking Supervision. This set specifically deals with the amount of capital that banks should put aside to protect against the various financial and operational risks they face.
BCUC	British Columbia Utilities Commission
BN	Billion
BPA	Bonneville Power Administration
BSD	Business Services Department
BTF	Before-the-fact
CAD	Canadian Dollars
CCRO	Committee of Chief Risk Officers
CDD	Cooling Degree Days
CDDHoward	CDDHoward Consulting Ltd
CDWR	California Department of Water Resources
CEATI	The Centre for Energy Advancement through Technological Innovation
CEC	California Energy Commission
CEO	Chief Executive Officer
CFaR	CashFlow at Risk
CFO	Chief Financial Officer
CICA	Canadian Institute of Chartered Accountants
CME	Chicago Mercantile Exchange
Consultant	New York based Consultant retained by MH under a Master Service Agreement, dated January 1, 2006, to review MH's risk processes and policies
Consultant's Reports	Reports generated by the Consultant. See Section 1.3.2 for a

	comprehensive list of these.
COSO	Committee of Sponsoring Organizations
CPI	Consumer Price Index
CPUC	California Public Utilities Commission
CRO	Chief Risk Officer
CRS Report	Congressional Research Service Report
CSA	Canadian Standards Association
CT	Combustion turbine
CVaR	Credit Value-at-Risk
DA	Day-Ahead
DC	Direct Current
Dependable Energy	Energy available from hydro in the lowest historic river flow conditions, and also includes energy sourced from wind, thermal and firm and contracted non-firm imports from out-of-province
Diversity Agreement	Agreements to exchange capacity and associated energy between the counterparty's power systems whose peak loads occur at different times in a year
E&Y	Ernst & Young LLP
EaR	Earnings at Risk
ELT	Executive Leadership Team
EMMA	Energy Management and Maintenance Analysis
EPM	Export Power Marketing
EPRMC	Export Power Risk Management Committee
ERAC	Energy Risk Assessment and Controls
ERC	Executive Risk Committee
ERM	Enterprise Risk Management
ERMC	Energy Risk Management Committee
FAS	Financial Accounting Standard
FERC	Federal Energy Regulatory Commission
Forecast Run	Run based on PIRA forecast
FSA	Financial Services Authority
FTE	Full-Time Equivalent
FTR	Firm Transmission Rights
Front Office	Responsible for initiating and managing power trades
FY	Fiscal Year
GAAP	Generally Accepted Accounting Principles
GDP	Gross Domestic Product
GDP-IPD	Gross Domestic Product – Implicit Price Deflator
GJ	Gigajoules
GL	General Ledger
GRE	Great River Energy
GWh	Gigawatt hour
HDD	Heating Degree Days

HE	Hour Ending
HERMES	Hydro-Electric Reservoir Management Evaluation System. MH main risk analysis and management tool.
HH	Henry Hub
HOEP	Hourly Ontario Energy Price
HQ	Hydro Quebec
HVDC	High Voltage Direct Current
ICE	Intercontinental Exchange
ICF	ICF Consulting
IESO	Independent Electricity System Operator
IFF	Integrated Financial Forecast
IFRS	International Financial Reporting Standards
IMO	Independent Electricity Market Operator
IRO	Independent Risk Officer
ISDA	International Swaps and Derivatives Association
ISO	International Standards Organization
Issues	The components of an assertion(s) that reflect an alleged fundamental deficiency in MH
IT	Information Technology
Kcfs	Kilo Cubic Feet per Second
KM	Kilometres
KPMG	KPMG LLP
kV	Kilovolt
KWh	Kilowatt hour
LD	Liquidated Damages
LIFFE	London International Financial Futures and Options Exchange
LMP	Locational Marginal Pricing
LP	Linear Programming
LRMC	Long Run Marginal Cost
MAPP	Mid-Continent Area Power Pool
MCP	Management Control Plan
MEC	Major Export Contracts
MH	Manitoba Hydro
MHA	*Manitoba Hydro Act*
MHEB	Manitoba Hydro-Electric Board
MHEBDA	*Manitoba Hydro-Electric Board Development Act*
Middle Office	Responsible for daily risk monitoring of transactions and positions and assessing various risks surrounding counterparty transactions and energy trading
MINN	Minnesota Hub
MISO	Midwest Independent Transmission System Operator
MISO OASIS	Midwest Independent Transmission System Operator Open Access Same Time Information System

MISO TEMT	Midwest Independent Transmission System Operator Transmission and Energy Markets Tariff
MM	Million
MMBtu	One million British Thermal Units
MMPA	Minnesota Municipal Power Agency
MN	Minnesota
MP	Minnesota Power
MRO	Midwest Reliability Organization
MTM	Mark-to-Market
MW	Megawatt
MWa	A measure of the total amount of energy available within the year. It reflects the amount of energy that would be produced by 1 MW of capacity operating at a 100% load factor. Thus, 1 Mwa is equal to 8,760 MWh, which reflects the fact that there are 8,760 hours within the year. (8,760 is the product of 24 hours and 365 days.) Mwa is a useful measure to use when comparing capacity and energy values.
NERC	North American Electric Reliability Corporation
NERA	National Economic Research Associates, Inc.
NNG Ventura	Northern Natural Gas – Ventura index
No Sale Scenario	This sequence excludes the export sales related to the WPS and MP contracts, the construction of Keeyask, and the planned U.S. transmission interconnection
NPP	New Product Process
NPV	Net Present Value
NSP	Northern States Power
NYPA	New York Power Authority
O&M	Operations and Maintenance
OCC	Office of the Comptroller of the Currency Bulletin
OCI	Other Comprehensive Income
OPG	Ontario Power Generation
Opportunity Sales	All sales in excess of Dependable Energy commitments and sold as either Opportunity Spot Sales with a term of less than 14 days (Day Ahead/Real Time) or Opportunity Term Sales with a term greater than 14 days.
Optimal Run	Run with perfect foresight
OSP	Outsource service provider
OTC	Over-the-Counter
OTP	Otter Tail Power
P&L	Profit and Loss
PFE	Potential Future Exposure
PIRA	PIRA Energy Group
PRISM	Power Risk System Model
PROMOD	A locational marginal price forecasting tool.

PRP	Power Resource Plan
PRT	Pattern Recognition Technology
PS&O	Power Sales and Operations Division within Manitoba Hydro
PSOMC	Power Sales and Operations Market Committee at Manitoba Hydro
PUB	The Public Utilities Board of Manitoba
PURPA	Public Utilities Regulatory Policies Act
PV	Present Value
QF	Qualifying Facility
QSIM	Flow Simulation Model used by MH to derive daily flow and elevation values along the hydraulic network affecting the MH generating system
RDD	Real-time Dynamic Dispatchable
Review	External Quality Review performed by KPMG
RFP	Request for Proposals
RMC	Risk Management Committee
ROC	Risk Oversight Committee
RPMA	Resource Planning and Market Analysis Department
R.S.	Reserve Storage
RT	Real Time
S&P	Standard & Poor's
Sale Scenario	2010 Power Resource Plan
SCC	System Control Centre
SMMPA	Southern Minnesota Municipal Power Agency
SRP	Salt River Project
SPLASH	Simulation Program for Long-term Analysis of System Hydraulics. MH model for long-range system planning applications.
TFS	Tradition Financial Services
Themes	Themes identified by KPMG in Exhibit 1-1 of this report
TLR	Transmission Loading Relief
TMV	Tenaska Marketing Ventures / Tenaska Marketing Canada
TWh	Terawatt hour
UPA	United Power Association
US	United States of America
USD	United States Dollars
VaR	Value-at-Risk
VP	Vice President
WACC	Weighted Average Cost of Capital
WPS	Wisconsin Public Service

B

Appendix B: Phase 1 Report

KPMG

KPMG LLP

STRICTLY PRIVATE AND CONFIDENTIAL
NO REPRODUCTION OR DISTRIBUTION PERMITTED

Manitoba Hydro – External Quality Review Phase 1 Report

December 4, 2009
ADVISORY

AUDIT • TAX • ADVISORY

able of Contents

I. Introduction and Background

II. Determination of the Issues to be Addressed

III. Approach to Phase 2 Work

Appendices

A. Issues Templates

B. Phase 2 Teams

Introduction and Background

Purpose of report

- KPMG's work is structured into two phases.
- Phase 1 is to provide a conceptual outline to Manitoba Hydro ("MH") for our in-depth and independent study of the concerns raised with respect to MH's risk.
- The objective of this phase is for KPMG to get quickly up to speed on the relevant Issues and to identify the key questions to be addressed in Phase 2. In particular, in the event that it is not possible to examine all of the concerns in Phase 2, Phase 1 is intended to identify the most appropriate set of concerns to be addressed.
- This document represents the Phase 1 report.

Introduction and Background

Scope of work for Phase 1

- We have reviewed the allegations raised in the three reports from the Consultant. We have not yet reviewed any of the e-mails and therefore have not identified any additional allegations contained therein. (This will be done during Phase 2.)
- We have limited our review to the identification and categorization of the allegations. The only analysis we have conducted is that necessary to categorize and screen the allegations. (We have not yet assessed the substance of any of the allegations.)

Activities undertaken during Phase 1

- We have assembled and reviewed information:
  - Background materials related to the Issues:
    - Reports of the consultant
    - ICF International report
    - Risk Advisory reports
    - SPLASH Model Peer Review
    - MH Major Facilities Strategy
    - Other MH documents.
  - Internal audit group materials collected pursuant to its Terms of Reference.
- We have received initial briefings from MH personnel:
  - Chair
  - Senior Management
  - Power Sales and Operations
  - Internal Audit
  - Corporate Risk Management.

Introduction and Background

Activities undertaken during Phase 1 (continued)

- We developed a set of analytical tools for our Phase 1 work:
  - Screening criteria
  - Standardized template
  - Set of methodologies.
- We have conducted the following analyses:
  - Identified the allegations raised in the Consultant's three reports
  - Categorized the allegations into 17 logical groupings (called Issues) and assembled the Issues into six Themes.
  - Used the standardized template to summarize the 17 Issues and to consider those aspects of the Issues affecting our Phase 1 work
  - Applied the screening criteria to determine a selected set of Issues to be addressed in Phase 2

Introduction and Background

Activities undertaken during Phase 1 (continued)

- We have undertaken the necessary steps to begin work immediately on Phase 2. In particular:
  - We have established our teams for carrying out the Phase 2 work. (We will engage technical subconsultants where appropriate.)
  - We have developed orientation and training materials for the Phase 2 team members.
  - We have developed our project management structure and procedures.

Introduction and Background
Issue Themes

- The Themes that we have identified are as follows:
  - Risk Governance
  - Power Resource Management
  - Power Sales Management
  - Portfolio Monitoring and Reporting
  - Forecasting Models
  - Consultant's Access to Information.

ble of Contents

I. Introduction and Background

II. Determination of the Issues to be Addressed

III. Approach to Phase 2 Work

Appendices

A. Issues Templates

B. Phase 2 Teams

8.

Determination of the Issues to be Addressed in Phase 2
Screening criteria

- We developed a set of criteria to determine the Issues to be addressed in Phase 2.
- The criteria consist of both "Pass/Fail" criteria and "Priority Ranking" criteria.
- The "Pass/Fail" criteria are applied first and those Issues that "pass" are then evaluated by the "Priority Ranking" criteria.
- Three "Pass/Fail" criteria:
  - *Is the Issue amenable to an independent and objective analysis?*
  - *Can the Issue be addressed on a timely basis?*
  - *Is it possible to obtain qualified resources to assist in addressing the Issue (if required)?*

Determination of the Issues to be Addressed in Phase 2
Screening criteria (continued)

- One "Priority Ranking" criterion:
  - *How significant is the Issue to Manitoba Hydro in fulfilling its mandate?*

- Section 2 of ***The Manitoba Hydro Act, C.C.S.M. c. H190***

  "The purposes and objects of this Act are to provide for the continuance of a supply of power adequate for the needs of the province, and to engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power and, in addition, are

  (a) to provide and market products, services and expertise related to the development, generation, transmission, distribution, supply and end-use of power, within and outside the province; and

  (b) to market and supply power to persons outside the province on terms and conditions acceptable to the board."

III. Determination of the Issues to be Addressed in Phase 2

Defining Issues

- As mentioned previously, an Issue is a logical grouping of allegations contained in the three reports.
- Each Issue has been designed to capture the essential core of one or more allegations.
- The allegations that are within the scope of our work are those involving:
  - Processes
  - Tools
  - Documentation
  - Decision making

  In this context, the set of Issues is intended to be comprehensive.
- Each Issue will be addressed both as at the period of time referenced in the three reports, and as at the current time.

III. Determination of the Issues to be Addressed in Phase 2

Defining Issues (continued)

- An Issue captures the component(s) of an allegation(s) that reflects an alleged underlying deficiency in MH, rather than the alleged consequences of that deficiency:
  - For example, the Consultant alleges deficiencies with regards to the RFP process that MH uses for power sales. The Consultant further alleges that those deficiencies expose MH to significant risk of financial penalty. We define the Issue to be the alleged deficiencies in the process, not the alleged risk of financial penalties.
  - Both an Issue and its alleged consequences will be addresses in the context of Phase 2.
- We are confident that our Phase 1 work has resulted in a robust identification of Issues but some changes are possible. For example:
  - New issues may emerge from the Phase 2 review of e-mails
  - New issues may emerge from contact with the Consultant
  - Other Phase 2 work may result in new issues being identified (e.g. one issue may be split into two)

Note that there have been some minor changes in the list of Issues and Themes from the presentation of November 26,2009 to reflect further progress in the conduct of Phase 1.

Determination of the Issues to be Addressed in Phase 2

Identified Themes/Issues

1. Risk governance

1.1 Independence of the Middle Office function

1.2 Resourcing and authorities relating to energy risk management.

2. Power resource management

2.1 Treatment of risk (identification, measurement, treatment)

3. Power sales management

3.1 Pricing methodology for firm power sales

3.2 Risk capital reserves

3.3 Power sales RFP process

3.4 Long-term contracts structure.

4. Portfolio monitoring and reporting

4.1 Methodology for valuation and hedging (mark-to-market)

5. Forecasting models

5.1 Appropriateness of inputs and model logic relating to

- 5.1.1 Pricing
- 5.1.2 Water volume
- 5.1.3 Key model parameters
- 5.1.4 Lake water level balances
- 5.1.5 Market rules.

5.2. Treatment of optionality

- 5.2.1 Plant cycling
- 5.2.2 Storage.

5.3 Validation of models

6. Consultant's access to information

6.1 Access to key information including models and data sources

II. Determination of the Issues to be Addressed in Phase 2

Description of Issues

- As mentioned previously, we have used a standard template to summarize relevant information about each issue.
- **Appendix A** contains the completed templates for each issue and the framework we used in completing the templates.

II. [illegible]etermination of the Issues [illegible] be Addressed in Phase 2

Screening results

Issue	Objective analysis [1]	Addressed in a timely basis	Qualified resources	Priority ranking
1. Risk governance				
1.1 Independence of the middle office function	**Pass**	**Pass**	**Pass**	**High**
1.2 Resourcing and authorities relating to energy risk management	**Pass**	**Pass**	**Pass**	**High**
2. Power resource management				
2.1 Treatment of risk (identification, measurement, treatment)	**Pass**	**Pass**	**Pass**	**High**
3. Power sales management				
3.1 Pricing methodology for firm power sales	**Pass**	**Pass**	**Pass**	**High**
3.2 Risk capital reserves	**Pass**	**Pass**	**Pass**	**High**
3.3 Power sales RFP process	**Pass**	**Pass**	**Pass**	**High**
3.4 Long-term contracts structure	**Pass**	**Pass**	**Pass**	**High**
4. Portfolio monitoring and reporting				
4.1 Methodology for valuation and hedging (mark-to-market)	**Pass**	**Pass**	**Pass**	**High**

[1] Legend:

***Objective analysis**: Is the issue amenable to an independent and objective analysis?*
***Addressed in a timely basis**: Can the issue be addressed on a timely basis?*
***Qualified resources**: Is it possible to obtain qualified resources to assist in addressing the issue (if required)?*
***Priority ranking**: How significant is the issue to Manitoba Hydro in fulfilling its mandate?*

II. Determination of the Issues to be Addressed in Phase 2

Screening results (continued)

Issue	Objective analysis [1]	Addressed in a timely basis	Qualified resources	Priority ranking
5. Forecasting models				
5.1 Appropriateness of inputs and model logic relating to				
5.1.1 Pricing	**Pass**	**Pass**	**Pass**	**High**
5.1.2 Water volume	**Pass**	**Pass**	**Pass**	**High**
5.1.3 Key model parameters	**Pass**	**Pass**	**Pass**	**High**
5.1.4 Lake water level balances	**Pass**	**Pass**	**Pass**	**High**
5.1.5 Market rules	**Pass**	**Pass**	**Pass**	**High**
5.2. Treatment of optionality				
5.2.1 Plant cycling	**Pass**	**Pass**	**Pass**	**High**
5.2.2 Storage	**Pass**	**Pass**	**Pass**	**High**
5.3 Validation of models	**Pass**	**Pass**	**Pass**	**High**
6. Consultant's access to information				
6.1 Access to key information including models and data sources	Fail	**Pass**	**Pass**	**Low**

[1] Legend:

***Objective analysis**: Is the issue amenable to an independent and objective analysis?*
***Addressed in a timely basis**: Can the issue be addressed on a timely basis?*
***Qualified resources**: Is it possible to obtain qualified resources to assist in addressing the issue (if required)?*
***Priority ranking**: How significant is the issue to Manitoba Hydro in fulfilling its mandate?*

II. Determination of the Issues to be Addressed in Phase 2

Selected set of Issues for Phase 2

- Only one of the 17 Issues "failed" during the "Pass/Fail" evaluation stage.
- We are proposing that the remaining 16 Issues be carried forward to Phase 2.
- These 16 remaining Issues are grouped into five remaining Themes (i.e., the issue which "failed" was the only issue in its theme).

Table of Contents

I. Introduction and Background

II. Determination of the Issues to be Addressed

III. Approach to Phase 2 Work

Appendices

A. Issues Templates

B. Phase 2 Teams

III. Approach to Phase 2 Work

How will we determine when an issue has been resolved?

- An Issue will be resolved when we are in a position to either concur with or reject the findings and recommendations of the Consultant.
- Our general approach will be to employ a variety of methodologies to generate multiple lines of evidence for consideration. In addition, it will be necessary to develop an understanding of the relative significance of each line of evidence, and then use our professional judgment to determine whether we concur with or reject the findings and recommendations of the Consultant.
- Our work may not result in either a total concurrence with or rejection of an Issue; in some instances, it may be that we concur with some elements of an issue and reject others.
- The specifics of how this general concept will be applied may evolve during the conduct of Phase 2.

III. Approach to Phase 2 Work
Detailing an Issue

- The initial stages of Phase 2 will include a series of steps designed to deepen our understanding of each issue before we use specific methodologies to address that issue.
- These steps will include:
  - Developing a complete mapping of the detailed allegations contained within the three Consultant reports to the 16 Issues identified by KPMG, to ensure that all the allegations are considered
  - Identifying the allegations contained in the e-mails and incorporating them into the Issues categorization and mapping
  - Obtaining and reviewing written documents available from MH relating to the substance of each issue
  - Interviewing relevant MH staff to obtain their perspective on each issue
  - To the extent necessary, meeting with the Consultant to obtain further clarification on the nature of the deficiencies underlying each Issue (timing to be determined)
  - Developing an initial view on what will be required to resolve each issue

III. Approach to Phase 2 Work
Methodologies to be used to address Issues

- As mentioned earlier, our scope addresses Issues involving:
  - Processes
  - Tools
  - Documentation
  - Decision making
- This scope influences the identification of methodologies to be used in Phase 2.

III. Approach to Phase 2 Work

Methodologies to be used to address Issues (continued)

- We have identified a set of common methodologies that we envision applying to all or many of the Issues:
  - Review of MH documentation and data
  - MH interviews
  - Consultant interviews
  - Third party interviews
  - Benchmarking and Best Practices Analysis
  - Literature review
  - Analysis of external data
  - Analysis of model logic
  - Directed model runs
  - Use of new or existing models
- These methodologies will be applied to individual issues, as appropriate. Their use may evolve in response to circumstances.
- Other Issue-specific methodologies may also be employed.
- Appendix A summarizes our current thinking on the most relevant methodologies for individual Issues.

Team organization

- As mentioned previously, we have grouped the 16 Issues into five Themes.
- We have assigned teams of professionals to address each of the Themes, as follows:
  - Risk Governance Team
  - Power Resource Management Team
  - Power Sales Management Team
  - Portfolio Monitoring and Reporting Team
  - Forecasting Models Team.
- These five teams are supplemented by three support teams:
  - Due Diligence and Oversight Team
  - Project Management Team
  - Task Execution Team.
- Each team is led by a team leader with specialized skills in the pertinent Issues.
- See **Appendix B** for details on the teams.

III. Approach to Phase 2 Work

Organizing and coordinating ourselves for Phase 2 (continued)

Project management

- We will maintain a consistent approach to investigating and reporting on issues, including:
  - Standardized orientation and training
  - Standardized formats for internal documentation and reporting of results
  - Centralized filing of information received (to ensure its accessibility to all teams)
  - Daily meetings of team leaders
  - Use of the Due Diligence and Oversight Team to vet all key decisions relating to the conduct of the work
  - Designated MH contacts

How we will work with MH

- Together we will develop protocols for interactions with MH.
- The topics to be addressed in these protocols will include:
  - Describing our mandate to MH staff
  - Identifying who we should talk to within MH
  - Determining protocols for contacting a member of MH staff
  - Making a formal information request
  - Addressing any instances of insufficient cooperation
  - Sharing of information among MH management, Board and KPMG
  - Obtaining assurance that we have received complete information
  - Retaining and compensating subconsultants

Anticipated major challenge

- One of the key complexities that we envision having to address in the conduct of Phase 2 relates to our communications with the Consultant. Specifically, there is considerable uncertainty regarding what will be learned from the Consultant and over what timeframe. This matter represents one of the key challenges we may face in conducting Phase 2 in a timely and comprehensive manner.
- While circumstances may influence our approach during the conduct of Phase 2 (i.e. cooperation versus non-cooperation of the Consultant), we will proceed under the assumption that we need to develop our own evidence path.
  - Establish in advance, with the agreement of MH, how much elapsed time we can devote to seeking information from the Consultant. Note that if information appears to be forthcoming, it may be difficult to adhere to any such limit.
- We propose to keep MH well-informed of our progress in this matter and seek direction, as appropriate.

III. Approach to Phase 2 Work
eporting

- We will report on a regular basis, to be determined with MH (+/- every two weeks).
- In addition, there may be specific circumstances that will require special meetings with MH. For example, we expect that we would do so just prior to our initial meeting with the Consultant.
- Our final deliverable will be a formal written report to the Audit Committee of MH.

Table of Contents

I. Introduction and Background

II. Determination of the Issues to be Addressed

III. Approach to Phase 2 Work

Appendices

A. Issues Templates

B. Phase 2 Teams

The fi[illegible]able below described the approach used by KPMG to complete the templates for each Issue.

Issue	Issue identification
Source of issue	This section identifies the page (or pages) in the Consultant's Report dated December 4th, 2006 where the Consultant first elaborates and develops the issue identified above. Where multiple elements of an issue are included, there is a separate source for each element. All allegations identified in the Consultant's second and third reports, dated January 8, 2008 and October 31, 2008, respectively, are grouped under the issues identified in the December 4, 2006 report.
Background regarding issue	This section identifies the alleged deficiency and then, where applicable, summarizes the Consultant's recommendations regarding that deficiency. KPMG has attempted to describe the Consultant's allegations and associated recommendations using the Consultant's wording from its Report. However, in certain cases KPMG was required to paraphrase the Consultant's allegations. KPMG has identified only the allegations and not MH's responses to those allegations.
Proposed methodology to address issue	This section provides a list of the methodologies that will likely be applied in addressing the issue.
Manitoba Hydro resource requirements	This section characterizes the extent of support that KPMG will likely require from MH in the course of addressing the issue.
Sub-consultant requirements	This section identifies where KPMG is likely to use sub-consultants to help in address an issue. Subconsultants are most likely to be required where the issue involves highly specialized expertise (e.g. hydrologic modeling).
Issue deliverable	This section identifies the nature of the outputs that will be produced in addressing the issue.
Confidentiality/disclosure issues	This section highlights any unique or critical issues related to confidentiality and information disclosure.

Glossary of terms

"EPM"	Export Power Marketing
"IFF"	Integrated financial forecast
"LD"	Liquidated damages
"MH"	Manitoba Hydro
"MISO"	Midwest Independent Transmission System Operator
"MTM"	Mark-to-market
"PS&O"	Power Sales and Operations
"Report"	Report prepared by the Consultant dated December 4th, 2006
"RFP"	Request for proposal

Issue	1. Risk governance 1.1 Independence of the middle office function
Source of issue	Page 4 of the Report
Background regarding issue	The Consultant alleges that, as MH integrates risk management into its corporate framework, it is imperative to segregate the duties involved in calculating and reporting the risk and financial exposure of MH from the business units responsible for operating-level decisions, trading and opportunistic deals. The Consultant alleges that segregation of these duties is an important internal control element of compliance programs because it mitigates errors and opportunities for corporate fraud and misstatement of financial earnings. The Consultant's allegation is that it is important to for the Middle Office function to have an independent reporting relationship.
Proposed Methodologies	☒ Review of MH Documentation and Data ☒ MH Interviews ☒ Consultant Interviews ☐ Third-Party Interviews ☒ Benchmarking and Best Practices Analysis ☒ Literature Review ☐ Analysis of Model Logic ☐ Analysis of External Data ☐ Directed Model Runs ☐ Use of Existing or New Models
Discussion	Resolution of the issue will include identifying best practices in other jurisdictions and comparing to MH practices.
Manitoba Hydro resource requirements	Limited. As part of this issue, we will need to understand and document MH's existing practices with respect to segregation of duties, but do not expect that this will call for major use of internal MH resources.
Sub-consultant requirements	Nil.
Issue deliverable	Report comparing actual MH practices against Consultant allegations and against standard industry practice. Discussion of the implications of differences observed.
Confidentiality/disclosure issues	No unique confidentiality issues.

A-2

Issue	1. Risk governance 1.2 Resourcing and authorities relating to energy risk management
Source of issue	Page 6 of the Report
Background regarding issue	The Consultant alleges that the energy risk management function of MH does not meet best practices. Specifically, the Consultant notes that there are limited risk management policies with inadequate ability for the Middle Office to perform an oversight role over PS&O and trading transactions. The Consultant infers that relevant risk management reports are not being utilized in the management of risk at MH. The Consultant argues that it is common industry practice for risk management to monitor on a regular basis market price and hedging valuations in order to manage corporate performance in line with the achievement of the IFF.
Proposed Methodologies	☒ Review of MH Documentation and Data ☒ MH Interview ☒ Consultant Interviews ☒ Third-Party Interviews ☒ Benchmarking and Best Practices Analysis ☒ Literature Review ☐ Analysis of Model Logic ☐ Analysis of External Data ☐ Directed Model Runs ☐ Use of Existing or New Models
Manitoba Hydro resource requirements	Moderate. As part of this issue, we will need to understand and document MH's existing practices with respect to the operation of the energy risk management function, but do not expect that this will call for major use of internal MH resources.
Sub-consultant requirements	Nil.
Issue deliverable	Report summarizing our findings with respect to resourcing practices, and comparing them to industry best practices.
Confidentiality/disclosure issues	No unique confidentiality issues.

Issue	2. Power resource management 2.1 Treatment of risk (identification, measurement, treatment)
Source of issue	Page 5 of the Report
Background regarding issue	The consultant alleges that MH is not adequately breaking down "drought risk" into its component sub-risks. Specifically, the consultant argues that a more appropriate categorization would be one disaggregating "drought risk" into components of market risk, volumetric risk, operational risk and credit risk. In addition a further perspective relating only to LD exposure regarding the export contracts should be utilized. To the extent each of the component risks within "drought risk" affects the overall portfolio risk differently both in magnitude and in nature, the Consultants states that these component risks should be identified separately, quantified individually and then managed accordingly (differentiating between those sub-risks which lie within its ability to influence and those that are truly outside of its control). The Consultant alleges that MH does not employ appropriate risk quantification tools and further does not manage risk at the appropriate component sub-risk level by focusing on "drought risk" management.
Proposed Methodologies	☒ Review of MH Documentation and Data ☒ MH Interview ☒ Consultant Interviews ☒ Third-Party Interviews ☒ Benchmarking and Best Practices Analysis ☒ Literature Review ☒ Analysis of Model Logic ☒ Analysis of External Data ☒ Directed Model Runs ☒ Use of Existing or New Models
Discussion	All of the methodologies are likely to be used extensively in addressing this issue, which has wide implications and touches many functions within MH.
Manitoba Hydro resource requirements	High. Significant interaction with MH staff will be required to fully understand current MH models and practices and the operational characteristics of the MH system. In addition, quantifying this issue may require directed model runs.
Sub-consultant requirements	Sub-consultant assistance may be required in quantifying the value of various types of risk and for the review of MH models, particularly as they relate to hydrologic modeling.
Issue deliverable	KPMG report will assess the merit of Consultants recommendations for the treatment of risk. In addition, some quantification of the significance of these risks and the degree of misstatement (if any) is likely to be required.
Confidentiality/disclosure issues	MH models may include proprietary algorithms and methodologies that must be protected from disclosure. In addition, system parameters may be commercially sensitive.

Issue	3. Power sales management 3.1 Pricing methodology for firm power sales
Source of issue	Page 13 of the Report
Background regarding issue	MH has and continues to enter into long-term fixed price energy sales contracts primarily with counter parties in the MISO marketplace. The Consultant alleges that MH is using incorrect pricing methodologies for the sales price in long-term energy contracts. Specifically, the Consultant alleges that MH: • is not properly making use of current market price information, and • is not properly identifying and quantifying all the risks (e.g. liquidated damages, volumetric risk, etc.) associated with such long-term supply contracts and therefore MH is not building in an appropriate risk premium in pricing these contracts. The Consultant acknowledges reasons cited by MH as to why it was willing to sell power for less than its apparent market value in these long-term contracts (i.e. because of the creation of transmission capacity and access), but rejects these as being valid reasons for such pricing. In this context, the Consultant recommends an overhaul of the pricing methodology used in the long-term fixed price energy sales contracts.
Proposed Methodologies	☒ Review of MH Documentation and Data ☒ MH Interview ☒ Consultant Interviews ☒ Third-Party Interviews ☐ Benchmarking and Best Practices Analysis ☒ Literature Review ☐ Analysis of Model Logic ☒ Analysis of External Data ☒ Directed Model Runs ☒ Use of Existing or New Models
Manitoba Hydro resource requirements	High. This is a key issue for MH with major implications for its long-term business strategy. Hence, it will be the focus of significant attention in the review. Addressing the issue also crosses a large number of functional disciplines; it requires knowledge of the MH system from an operational perspective but also touches on electricity market, financing, and risk management issues. We expect that many discussions will be required with MH management and staff, and also that some model runs and model development may be called for.
Sub-consultant requirements	Subconsultants may be used to help quantify risks.
Issue deliverable	Report that addresses the substance of the issue and that provides estimates of its potential business and financial implications. Report will also address broader business implications.
Confidentiality/disclosure issues	In particular, information with respect to MH's strategies for power contracting and the pricing provisions of specific contracts are commercially sensitive .

A.K

Issue	3. Power sales management 3.2 Risk capital reserves
Source of issue	Page 13 of the Report
Background regarding issue	MH has and continues to enter into long-term fixed price energy sales contracts, primarily with counter parties in the MISO marketplace. As described in Issue 3.1, the Consultant alleges that MH is using incorrect pricing methodologies for the sales price in long-term energy contracts and in particular is not properly identifying and quantifying all of the risks associated with having entered into long-term supply contracts. In that context, the Consultant alleges that MH is also not reserving a sufficient amount of risk capital for the export sales business. The Consultant recommends in the Report the immediate cessation of EPM sale of long-term contracts until MH has an appropriate amount of risk capital reserved for this business.
Proposed Methodologies	☒ Review of MH Documentation and Data ☒ MH Interviews ☒ Consultant Interviews ☐ Third-Party Interviews ☒ Benchmarking and Best Practices Analysis ☒ Literature Review ☐ Analysis of Model Logic ☒ Analysis of External Data ☒ Directed Model Runs ☐ Use of Existing or New Models
Manitoba Hydro resource requirements	High. Meetings will be required with representatives of a broad range of functions within MH, given the strategic nature of this issue. Some modeling assistance will be required but likely not as extensive as for some other issues with a more day-to-day operational focus.
Sub-consultant requirements	Use of sub-consultants is not expected.
Issue deliverable	Report that addresses the substance of the issue.
Confidentiality/disclosure issues	MH pricing methodologies are commercially sensitive.

A-6

Issue	3. Power sales management 3.3 Power sales RFP process	
Source of issue	Page 16 of the Report	
Background regarding issue	MH has and continues to enter into long-term fixed price energy sales contracts primarily with counter parties in the MISO marketplace. The Consultant alleges that the process by which MH issues RFPs in the long-term markets exposes it to a significant risk of financial penalty. The Consultant recommends an overhaul of the RFP pricing process, and is in particular focused on the duration of holding its prices open and the terms offered.	
Proposed Methodologies	☒ Review of MH Documentation and Data ☒ MH Interviews ☒ Consultant Interviews ☐ Third-Party Interviews ☒ Benchmarking and Best Practices Analysis	☐ Literature Review ☒ Analysis of Model Logic ☒ Analysis of External Data ☒ Directed Model Runs ☒ Use of Existing or New Models
Manitoba Hydro resource requirements	Moderate.	
Sub-consultant requirements	Use of sub-consultants is not expected.	
Issue deliverable	Report that addresses the substance of the issue. Changes to the power sales RFP process will be recommended if appropriate.	
Confidentiality/disclosure issues	Contract price provisions are commercially sensitive.	

Issue	3. Power sales management 3.4 Long-term contracts structure
Source of issue	Page 17 of the Report
Background regarding issue	MH has and continues to enter into long-term fixed price energy sales contracts primarily with counter parties in the MISO marketplace. The Consultant alleges that MH has sub-optimized these arrangements due to the use of certain terms in the contracts. The Consultant recommends: • shortening the duration of these contracts to at most two years; • sharing of risk in the market prices and premiums being charged; • index or floating price provisions being included; and • increased optionality to MH's benefit.
Proposed Methodologies	☒ Review of MH Documentation and Data ☐ Literature Review ☒ MH Interview ☐ Analysis of Model Logic ☒ Consultant Interviews ☒ Analysis of External Data ☒ Third-Party Interviews ☒ Directed Model Runs ☒ Benchmarking and Best Practices Analysis ☒ Use of Existing or New Models
Manitoba Hydro resource requirements	Moderate - High. We may need to call on MH analytical resources to model the implications of the contracting alternatives suggested by the Consultant. We will also need to understand MH's perspectives on the alternatives suggested, which will require time for interviews with MH personnel.
Sub-consultant requirements	Use of sub-consultants is not expected.
Issue deliverable	Report will address the merits of the Consultants recommendations and their business and financial implications.
Confidentiality/disclosure issues	No unique confidentiality issues.

Issue	4. Portfolio monitoring and reporting 4.1 Methodology for valuation and hedging (mark-to-market)
Source of issue	Page 6 of the Report
Background regarding issue	The Consultant acknowledges that MH does carry out a valuation of its portfolios but alleges that the valuation methodology is inadequate. Specifically, the Consultant argues that MH, and in particular its risk management function, should calculate what it deems to be the "true economic valuation" of portfolios, should separate and quantify the market exposure of risk, and should identify the true cost of hedging to arrive at an appropriate valuation and accordingly an appropriate determination of risk capital. To do so, the consultant argues that it is best standard practices to use MTM for these purposes.
Proposed Methodologies	☒ Review of MH Documentation and Data ☒ MH Interview ☒ Consultant Interviews ☐ Third-Party Interviews ☒ Benchmarking and Best Practices Analysis ☒ Literature Review ☒ Analysis of Model Logic ☒ Analysis of External Data ☒ Directed Model Runs ☒ Use of Existing or New Models
Manitoba Hydro resource requirements	Low-moderate. Some interaction will be required with MH staff to understand current MH practices and their rationale. We do not expect that time requirements will be high.
Sub-consultant requirements	Use of sub-consultants is not expected.
Issue deliverable	Report will address the merit of the Consultant's recommendations.
Confidentiality/disclosure issues	Information on MH's market position is commercially confidential.

A-9

Issue	5. Forecasting models 5.1 Appropriateness of inputs and model logic relating to: 5.1.1 Pricing
Source of issue	Page 10 of the Report
Background regarding issue	The Consultant alleges that the HERMES model is not based on current market prices and that it needs to do so in order to serve as an appropriate basis for decisions made to release water. Specifically, the Consultant alleges that the prices used in the HERMES model are static stale prices that should be updated regularly to reflect today's broker quotes and true market environment. The Consultant alleges that doing so prevents MH from optimizing its financial performance in selling surplus power or buying hedges as these relate to decisions made to release water.
Proposed Methodologies	☒ Review of MH Documentation and Data ☒ MH Interview ☒ Consultant Interviews ☐ Third-Party Interviews ☒ Benchmarking and Best Practices Analysis ☐ Literature Review ☒ Analysis of Model Logic ☒ Analysis of External Data ☒ Directed Model Runs ☒ Use of Existing or New Models
Manitoba Hydro resource requirements	Moderate. MH analytical resources may be required to help quantify the magnitude of this issue from a financial perspective.
Sub-consultant requirements	Use of sub-consultants is not expected.
Issue deliverable	Report will quantify the potential financial impact of the use of current market prices and assess the Consultant's recommendations.
Confidentiality/disclosure issues	Pricing data may be commercially sensitive.

Issue	5. Forecasting models 5.1 Appropriateness of inputs and model logic relating to: 5.1.2 Water volume
Source of issue	Pages 18 and 21 of the Report
Background regarding issue	The Consultant alleges that the MH models sub-optimize their treatment of water volumes. Specifically, the Consultant recommends: • improvements to its method of antecedent forecasting of rainfall (e.g. use of backtesting to validate the antecedent forecasting methodology and possible use of weather derivatives); and • improvements to the methods in HERMES used to forecast water flows (e.g. average versus median, backtesting, and completeness of historical data).
Proposed Methodologies	☒ Review of MH Documentation and Data ☒ MH Interview ☒ Consultant Interviews ☒ Third-Party Interviews ☒ Benchmarking and Best Practices Analysis ☒ Literature Review ☒ Analysis of Model Logic ☐ Analysis of External Data ☒ Directed Model Runs ☒ Use of Existing or New Models
Manitoba Hydro resource requirements	Moderate - High. Use of MH analytical resources will be required to understand existing models and the implications of alternatives. Issue complexity suggests resource requirements may be high.
Sub-consultant requirements	Experts in hydrologic modeling will likely be required to assist in addressing this issue.
Issue deliverable	Report will address the substance of the allegations. Report will likely include outputs from related model runs
Confidentiality/disclosure issues	MH models may include proprietary algorithms and methodologies that must be protected from disclosure. In addition, system parameters may be commercially sensitive.

Issue	5. Forecasting models 5.1 Appropriateness of inputs and model logic relating to: 5.1.3 Key model parameters
Source of issue	Pages 23 and 31 of the Report
Background regarding issue	The Consultant notes that the SPLASH and HERMES models utilize different sets of internal model parameters for calibrating the conversion factor of water flow to power from each hydro plant. Specifically, the Consultant identifies that the HERMES model uses a single point estimate of production coefficient along with an efficiency curve and Head to Tail race elevation, whereas SPLASH uses an output curve which addresses a more fully the spectrum of flows (although it is missing some of the seasonality in the shoulder months of the curves and should use expanded winter curves). The Consultant further noted issues regarding some modeling approximations in the HERMES model as well as the use of "model adjustment factors" (which are sometimes manually changed). The Consultant recommended that MH undertake on-going calibration and updates to both of these models.
Proposed Methodologies	☒ Review of MH Documentation and Data ☒ MH Interview ☒ Consultant Interviews ☒ Third-Party Interviews ☒ Benchmarking and Best Practices Analysis ☒ Literature Review ☒ Analysis of Model Logic ☐ Analysis of External Data ☒ Directed Model Runs ☒ Use of Existing or New Models
Manitoba Hydro resource requirements	Low-Moderate. Assistance from MH analytical resources will be required. However, this issue is relatively narrow in scope so that required resources will likely be moderate.
Sub-consultant requirements	Assistance of sub-consultants may be required.
Issue deliverable	Report will address the substance of the issue and provide recommendations for improvement, as appropriate.
Confidentiality/disclosure issues	No unique confidentiality issues.

Issue	5. Forecasting models 5.1 Appropriateness of inputs and model logic relating to: 5.1.4 Lake water level balances
Source of issue	Page 8 of the Report
Background regarding issue	The Consultant identifies two issues relating to lake levels: • The SPLASH model assumes "perfect foresight" of lake ending levels which in the real world is impossible to attain • The MH models (in particular HERMES) are based on an approach in which opening lake levels for the next fiscal year are equal to the closing lake levels in the current year. Doing so allows PS&O management to defer for at least one year losses which the Consultant argues should be recognized in the current fiscal year, and thereby financial management is being provided inaccurate information upon which to base its corporate risk management and financial reporting decisions.
Proposed Methodologies	☒ Review of MH Documentation and Data ☒ MH Interview ☒ Consultant Interviews ☒ Third-Party Interviews ☒ Benchmarking and Best Practices Analysis ☐ Literature Review ☒ Analysis of Model Logic ☒ Analysis of External Data ☒ Directed Model Runs ☒ Use of Existing or New Models
Manitoba Hydro resource requirements	Moderate. Assistance from MH analytical resources will be required. Meetings will also be required to understand nature of , and rationale for, the current approach and the validity of the Consultants characterization.
Sub-consultant requirements	Experts in hydrologic modeling may be required to assist in addressing this issue.
Issue deliverable	Report that identifies MH current practices, their implications, and the accuracy of the Consultant's observations.
Confidentiality/disclosure issues	No unique confidentiality issues.

Issue	5. Forecasting models 5.1 Appropriateness of inputs and model logic relating to: 5.1.5 Market rules
Source of issue	Page 11 of the Report
Background regarding issue	The Consultant alleges that the HERMES model has not been updated to stay current with the rules of the U.S. export market. Specifically, with the advent of MISO, HERMES' market monitoring and pricing, and hydrologic options have not been updated to stay current with market rules. The Consultant suggested an immediate revamp and overhaul of the HERMES model with an upgrade to incorporate key market parameters and considerations of the transactional MISO environment.
Proposed Methodologies	☒ Review of MH Documentation and Data ☒ MH Interview ☒ Consultant Interviews ☐ Third-Party Interviews ☒ Benchmarking and Best Practices Analysis ☐ Literature Review ☒ Analysis of Model Logic ☒ Analysis of External Data ☒ Directed Model Runs ☒ Use of Existing or New Models
Manitoba Hydro resource requirements	Moderate. MH models and analytical resources may be required to quantify impact of suggested model improvements.
Sub-consultant requirements	Use of sub-consultants is not expected.
Issue deliverable	Report that addresses the substance of the allegations and that provides recommendations for improvements, if applicable. Runs will may be undertaken to quantify the financial impact of any observed deficiencies.
Confidentiality/disclosure issues	No unique confidentiality issues.

Issue	5. Forecasting models 5.2 Treatment of optionality: 5.2.1 Plant cycling
Source of issue	Page 12 of the Report
Background regarding issue	In line with 5.1.1, the Consultant alleges that MH inappropriately values plant cycling optionality and that HERMES is based on intrinsic option valuation which is disconnected from available market prices. Specifically, the Consultant notes the exclusion of any market derivative valuation that takes into consideration option volatility and other option valuation parameters as well as current market performance regarding on-off peak price spread. In this context, the Consultant recommends an overhaul of the market pricing conditions in HERMES.
Proposed Methodologies	☒ Review of MH Documentation and Data ☒ MH Interview ☒ Consultant Interviews ☐ Third-Party Interviews ☒ Benchmarking and Best Practices Analysis ☒ Literature Review ☒ Analysis of Model Logic ☒ Analysis of External Data ☒ Directed Model Runs ☒ Use of Existing or New Models
Manitoba Hydro resource requirements	Moderate. Evaluation of the Consultant's proposed changes, if required, may require some meaningful analytical effort.
Sub-consultant requirements	Use of sub-consultants is not expected.
Issue deliverable	Report that addresses the substance of the issue.
Confidentiality/disclosure issues	Pricing data may be sensitive.

Issue	5. Forecasting models 5.2 Treatment of optionality: 5.2.2 Storage	
Source of issue	Pages 25, 27 and 29 of the Report	
Background regarding issue	The Consultants notes a variety of deficiencies in the modeling of optionality to store water in storage lakes. Specifically, the Consultant identifies among others: • the omission of certain secondary storage lakes in the SPLASH model; • similar concerns with regard to the HERMES model; • errors in starting lake level balances in the HERMES model; • differences in the HERMES and SPLASH models in their choice of lakes from which to withdraw storage as well as the timing and amount by which the lake levels are to be replenished, leading to sub-optimized performance; and • differences in the HERMES and SPLASH models in their achievement of year end water levels. The Consultant recommends that improvements to the models to address these deficiencies (e.g. backtesting and on-going model calibration) be carried out.	
Proposed Methodologies	☒ Review of MH Documentation and Data ☒ MH Interview ☒ Consultant Interviews ☒ Third-Party Interviews ☒ Benchmarking and Best Practices Analysis	☐ Literature Review ☒ Analysis of Model Logic ☐ Analysis of External Data ☒ Directed Model Runs ☒ Use of Existing or New Models
Manitoba Hydro resource requirements	High. Addressing this issue will require significant support from and interaction with MH personnel with an understanding of MH's models and system characteristics. It is likely that many directed model runs will be required to quantify the implications of this issue.	
Sub-consultant requirements	Experts in hydrologic modeling will likely be required to assist in addressing this issue.	
Issue deliverable	Report that addresses the modeling of storage and optionality. Summarizes of model runs and recommendations for improvement will be included as appropriate.	
Confidentiality/disclosure issues	MH models may include proprietary algorithms and methodologies that must be protected from disclosure. In addition, system parameters may be commercially sensitive.	

Issue	5. Forecasting models 5.3 Validation of models
Source of issue	Page 18 of the Report
Background regarding issue	Forecasts from models, such as HERMES, are based on inputs and model logic (i.e. the formulas and computational methods embedded in the model). Forecasts generated from models can be inaccurate either because of flaws in the model logic or errors in the inputs to the model (which are typically forecasts themselves). Back testing is a means by which errors in the inputs can be removed in order to verify the appropriateness of the model logic. Specifically, back testing involves doing a model run with inputs based on actually observed input parameters (e.g. actual snow fall versus forecast snowfall) and comparing the resulting model output against actual observed modeled outputs (e.g. actual lake level versus lake levels estimates generated by the model). The degree to which the "backcast" tracks reality gives an indication of the validity of the model logic. The Consultant alleges that MH does not back test its HERMES or SPLASH models. Accordingly, the Consultant argues that management decisions and reports based on the outputs of these two models may be flawed.
Proposed Methodologies	☒ Review of MH Documentation and Data ☒ MH Interview ☒ Consultant Interviews ☐ Third-Party Interviews ☐ Benchmarking and Best Practices Analysis ☐ Literature Review ☐ Analysis of Model Logic ☐ Analysis of External Data ☒ Directed Model Runs ☒ Use of Existing or New Models
Manitoba Hydro resource requirements	Low-Moderate Effort will be greater to the extent that we need to undertake backtesting of MH models. If we can confirm that MH has already done backtesting, then the level of effort will be lower.
Sub-consultant requirements	Use of sub-consultants is not expected.
Issue deliverable	Report that address the substance of the issue.
Confidentiality/disclosure issues	No unique confidentiality concerns.

Issue	6. Consultant's access to information 6.1 Access to key information including models and data sources
Source of issue	Page 2 of the Report
Background regarding issue	On numerous occasions in the Report, the Consultant alleges that access to information required to complete various elements of the analysis was denied. On numerous occasions, the Consultant made use of what data that was available including interpolations to arrive at conclusions/recommendations but provided a disclaimer in the Report either cautioning regarding the use of the results or stating that conclusions/recommendations may change if the data was made available.
Proposed Methodologies	☒ Review of MH Documentation and Data ☒ MH Interview ☒ Consultant Interviews ☐ Third-Party Interviews ☐ Benchmarking and Best Practices Analysis ☐ Literature Review ☐ Analysis of Model Logic ☐ Analysis of External Data ☐ Directed Model Runs ☐ Use of Existing or New Models
Discussion of Methodologies	Addressing this issue primarily requires ascertaining the facts relating to information disclosure to the Consultant. It would be difficult if not impossible to be definitive on this issue, given the disagreements over what data were required to complete the scope of the work requested by MH.
Manitoba Hydro resource requirements	Difficult if not impossible to objectively assess. Resource requirements uncertain. This is further complicated by the fact that the scope of the Consultant's work appears to have changed from time to time and was also the subject of disagreements between MH and the Consultant.
Sub-consultant requirements	Nil.
Issue deliverable	Not applicable.
Confidentiality/disclosure issues	No unique confidentiality issues.

<u>Of the 17 issues, this is the only one that failed, based on the considerations above.</u>

A-18

Table of Contents

I. Introduction and Background

II. Determination of the Issues to be Addressed

III. Approach to Phase 2 Work

Appendices

A. Issues Templates

B. Phase 2 Teams

Appendix B

Phase 2 Teams

Phase 2 team structure

- Dedicated team per theme
- Identified team lead and backup
  - Overall direction and co-ordination
  - Daily meetings of team leads
- Team membership reflective of competencies and experience required to address Issues within theme
  - Team membership may be expanded as required
- Though teams will operate independently, across teams there will be a high degree of information sharing recognizing the degree of overlap in Issues/functions.

Phase 2 team structure (continued)

- Each team will regularly report to a senior level Due Diligence and Oversight Team
- Strong project management support provided by a dedicated Project Management Team
- A separate Task Execution Team available to support all teams by undertaking discrete tasks such as:
  - Cross referencing emails and consultant reports to Issues
  - Decisions and governance evidence collection (e.g. assembling MH's export power management committee minutes).

Phase 2 Teams

Theme 1	Risk Governance Team
Lead:	Craig Fossay
Backup:	Beth Cassells
Members:	Frank Chen
	TBD

Theme 2	Power Resource Management Team
Lead:	Frank Chen
Backup:	Rob Sutherland
Members:	Diana Lowe
	Anurag Gupta

Theme 3	Power Sales Management Team
Lead:	Anurag Gupta
Backup:	Jonathan Erling
Members:	TBD
	TBD

Theme 4	Portfolio Monitoring and Reporting Team
Lead:	Norman Woltmann
Backup:	Frank Chen
Members:	Robert Kowalchuk
	TBD

Theme 5	Forecasting Models Team
Lead:	Jonathan Erling
Backup:	Paul Lan
Members:	Glen Bastedo
	Sub Consultant

Project Management Team	
Lead:	Will Lipson
Backup:	Steve Beatty
Members:	Bob Owen
	Patrick Clement
	Eric Wolfe
	Brian Kornelson

Due Diligence and Oversight Team	
Lead:	Steve Beatty
Backup:	Will Lipson
Members:	Bob Owen
	Mike Ross

Task Execution Team	
Lead:	Romeo Daley
Members:	Jennifer Walker
	Jeff Mathew
Task 1	Cross referencing emails and reports to issues list
Task 2	Decisions & governance evidence collection
Tasks ...	

B-3

Due Diligence and Oversight Team Members

- **Steve Beatty**
  - Partner in the Global Infrastructure and Projects (GIPG) group; Chair of GIPG Americas'
  - Extensive due diligence and advisory experience .
- **Will Lipson**
  - Partner in GIPG
  - Project management, process and transaction advisory experience.
- **Mike Ross**
  - Retired Partner in GIPG
  - Extensive due diligence and advisory experience and prior engagements with MH.
- **Bob Owen**
  - Partner in KPMG Winnipeg office
  - Extensive experience in power industry including MH specific experience.

Phase 2 Team Leads and Backups

- **Theme 1 – Risk Governance**
  - **Craig Fossay**
    - Partner in the Performance & Technology Group
    - Extensive governance advisory experience for both public sector and private sector clients.
  - **Beth Cassells**
    - Associate Partner in GIPG
    - Transaction and process specialist; prior experience working with MH.
- **Theme 2 – Power resource management**
  - **Frank Chen**
    - Senior Manager in the Advisory practice
    - Significant experience advising on risk governance and energy risk management to utilities, merchant power producers, regulatory agencies and corporations.
  - **Rob Sutherland**
    - Partner in GIPG and insolvency professional
    - Buy and sell side M&A and due diligence experience across multiple industries and sectors including power.

Phase 2 Team Leads and Backups (continued)

- **Theme 3 – Long-term power sales management**
  - **Anurag Gupta**
    - Senior Manager with GIPG and Power & Utilities practice
    - Power trading, structuring and energy risk management experience in both US and Canada; experience working in front and middle offices major energy companies
  - **Jonathan Erling**
    - Associate Partner in GIPG and Power & Utilities practice
    - Extensive experience in the energy sector on rate regulatory matters, valuation issues and transactions. Prior experience working with MH.
- **Theme 4 – Portfolio monitoring and reporting**
  - **Norman Woltmann**
    - Senior Manager in the Advisory practice
    - CA with over two decades of combined corporate finance and accounting/reporting experience within industry and in advisory mandates
  - **Frank Chen**

Phase 2 Team Leads and Backups (continued)

- **Theme 5 – Forecasting models**
  - **Jonathan Erling**
  - **Paul Lan**
    - Associate Partner in GIPG
    - Experienced modeler with extensive experience in developing and validating models across a range of transaction types and industry sectors
- **Project Management Team**
  - **Will Lipson**
  - **Steve Beatty**
  - **Bob Owen**
  - **Patrick Clement**
  - **Eric Wolfe**
  - **Brian Kornelsen**

C

Appendix C: List of MH Documents

Library 3

01 Materials Regarding the Consultant 3

01.01 Consultant's Reports 3
01.02 MH Reports Responses 3
01.03 MH Summaries and Updates 3
01.04 Agreements 4
01.05 Correspondence 4
01.06 Miscellaneous 4

02 Internal Manitoba Hydro Reports and Documentation 5

02.01 Business Plans 5
02.02 MH Power Resource Plans and Major Facilities Strategy 5
02.03 Organization Charts 6
02.04 Power Sales 6
02.04.01 Signing Authority for Power Contracts 6
02.04.02 Existing Long Term Contracts 6
02.04.03 Short Term Contracts 8
02.04.04 Term Sheets 8
02.04.05 Flowcharts 9
02.04.06 Miscellaneous 9
02.04.07 Monthly Reports 10
02.04.08 Financial Reporting Examples 10
02.05 Webtrader 11
02.06 Internal Audit 11
02.07 Miscellaneous 12
02.08 MH Terms of Reference 13
02.09 Policies and Procedures 13
02.10 Minutes 13
02.10.01 EPMRC 13
02.10.02 Board 14
02.10.03 PSOMC 16
02.10.04 Audit Committee 18
02.10.05 PRC 19
02.11 Risk Management 23
02.12 Models 24
02.12.01 HERMES Model Documentation 24
02.12.02 EMMA 2006 Reports to Consultant 24
02.12.03 Miscellaneous 32
02.12.04 SPLASH Model Documentation 33
02.12.05 Lake Level Coefficients and Storage Relationships 33
02.12.06 EMMA Flow Reports 34
02.12.07 EMMA Sensitivity Analysis 35

02.13 MH Credit 35
02.14 Monthly Management Reports 35
02.15 Weather Derivative Correspondence 36
03 Third Party Reports 36

Library

01 Materials Regarding the Consultant

01.01 Consultant's Reports

01. MH Risk Review 0708 (2006 12 04)
02. MH Risk Management Response (2008 01)
03. MH Long Term Contracts Risk Report (2008 10)
04. Letter to Schroeder re Public Utilities Board
05. Long Term Contracts Exec Sum – Middle Office Objectives (2008 11 05)
06. [Consultant] Risk Management Presentation (2008 01 10)
07. MH Middle Office Top 20 Risk Management Issues (2008 06 06)
08. MH Middle Office Long Term Contracts - Executive Summary (2008 11 05)
09. Long Term Contracts Section from Top 20 (2008 06 25)

01.02 MH Reports Responses

01. Review of the [Consultant] Report Dated December 4, 2006 PSO Division (2007 04 04)
02. Summary of Findings by [Consultant] – MH's Long-Term Contract Risks (2008 11 18)
03. Comments on [Consultant] Report Dated Dec 4-06 – PS&O and PS (May 2007)
04. Highlights of [Consultant] Report Dated Dec 4-06 and Jan 8-08 (2009 01 10)
05. MH Middle Office Corp Risk Mgmt – Preliminary Findings of Review of Reports (2008 05)
06. MH Middle Office Corp Risk Mgmt Review of [redacted] Reports (2008 10) NYC
07. MH Middle Office Comments on [Consultant] Long Term Contracts Risk Report (2008 10)
08. MH Middle Office Comments on [Consultant] Hydraulics Report Update (2008 10)
09. [redacted] Risk Management System Report (2006 09 22) NYC

01.03 MH Summaries and Updates

01. Summary – Whistle Blowing Allegations (2009 10 07)
02. The Whistleblowing Process at MH (2009 11 15)
03. Introduction – Allegations by [Consultant] (2007 04 16)
04. Briefing Note – Action Plan for Allegations by [Consultant] (2007 04 16)
05. Chronology of MH and [Consultant] Relationship (2007 03 18)
06. [Consultant] – Formation of the Contract (2007 03 28)
07. [Consultant] Chronology (2009 09 08)
08. [Consultant] Consulting – Audit Committee Update (2008 11 18)
09. [Consultant] Timeline (2009 11 15)
10. [Consultant]'s Financial Interest in Selling Licensing [redacted] Software (2009 11 15) NYC
11. Audit Committee of the Board – [Consultant] Consulting Update (2009 03 24)

12. Current Status of Investigations into Whistleblowing Allegations (2009 11 15)
13. Manitoba Hydro's Opinion on [Consultant]'s Engagement Performance (2009 11 15)
14. Summary of Payments to the [Consultant]

01.04 Agreements

01. [Consultant] Consulting Services Agreement with Manitoba Hydro (2004 03 16)
02. Consulting Services Agreement with MH (2007 08 21)
03. Consulting Services Agreement with MH (2008 01 31)
04. Draft Agreement between MH and [Consultant] (2005 02 11)
05. MSA between MH and the [Consultant] (2006 01 01)
06. Consultant Scope of Work (2005 02 11)
07. Consultant Scope of Work - Briefing Note 1 (2007 03 28)
08. Consultant Scope of Work - Briefing Note 2 (2009 10 21)

01.05 Correspondence

01. Email from [Consultant] Re Contract (2005 11 28)
02. Email from [Consultant] to Brennan (2007 04 12)
03. Email from KT Re – Sharing of ICF Reports – Privileged Solicitor-Client Communication (2009 10 26)
04. Email to Bob Owen from R.B. Brennan Re RFP – External Quality Review (2009 11 10)
05. Email to KT Re PUB Report Request (2009 11 04)
06. Email to Staff in PSO Department regarding Whistleblowing (2007 04 17)
07. Letter from Minister of Finance Re Audit (2009 10 21)
08. MH Interoffice Memo Re Sharing of [Consultant] Reports (2008 12 09)
09. MH Interoffice Memo Re Sharing of [Consultant] Reports (2009 10 08)
10. Email from [Consultant] Re Earnings Report (2006 12 13)

01.06 Miscellaneous

01. Export Power Contractual and Legal Risk Policy (2007 11 02)
02. Export Power Middle Office Terms of Reference
03. Independent Review of MH's Export Power Sales and Associated Risks – Terms of Reference (2008 12 19)
04. Issues of Credibility – [Consultant] (2009 11 15)
05. Materials to be provided to KPMG (2009 11 17)
06. McCullough Hydro Report (2009 12 02)
07. Hydro Response to McCullough Report (2009 12 07)
08. MH – Request for Tender (2009 02 03)
09. Planning Review Committee Members (5b)
10. Planning Review Committee Terms of Reference
11. Resume – [Consultant]
12. What Efforts Have Been Made to Confirm [Consultant]'s Qualifications (2009 11 06)
13. McCullough Report - Sept. 29, 2008 New York Risk Consultant - Hydraulics Report (2010 03 01)

14. MH Whistleblower speaks out - Transcript of Interview with KICK FM

02 Internal Manitoba Hydro Reports and Documentation

02.01 Business Plans

01. Power Trading Strategic Business Plan 2009-2010 (2009 05 06)
02. Power Sales and Operations Strategic Business Plan 2009-2010 (2009 04)
03. Export Power Marketing Department 2009-2010 Business Plan (2009 07 08)
04. Business Services Department (PSO) 2009-2010 Business Plan (2009 04 28)
05. Hydraulic Operations Department Business Plan 2008-2009
06. Hydraulic Operations Department Strategic Business Plan (2009 04)
07. Market Process and Technology Strategic Business Plan 2009-2010 (2009 05 07)
08. MH Corporate Strategic Plan 2009
09. MH Corporate Strategic Plan 2009 (definitions)
10. MH Corporate Strategic Plan 2009 (website)
11. MH Corporate Strategic Plan 2009 (Q1-June 2009 report)
12. MH Corporate Strategic Planning - Guidelines

02.02 MH Power Resource Plans and Major Facilities Strategy

01. Major Facilities Strategy – A Power Supply Perspective (2009 10)
02. MH 2005-06 Power Resource Plan Full Version (2005 07 06)
03. MH 2006-07 Power Resource Plan Full Version (2006 12 15)
04. MH 2007-08 Power Resource Plan Full Version (2008 01 21)
05. MH 2008-09 Power Resource Plan Full Version (2009 02 05)
06. Report on the 2004-05 Power Resource Plan (2004 07 22)
07. MH 2007-2008 Power Resource Plan
08. MH 2008-2009 Power Resource Plan
09. 2009 Forecast of Generation Costs and Interchange Rev 2009-11 (2009 08 19)
10. 2005 Export Price Forecast 2007-2040 (2005 04 13)
11. 2006 Electricity Export Price Forecast 2008-2040 (2006 05 10)
12. 2007 Electricity Export Price Forecast 2009-2040 (2007 05 01)
13. 2008 Electricity Export Price Forecast 2010-2050 (2008 04 29)
14. Export Price Forecast Review – Resource Planning and Market Analysis (2003 05)
15. Export Power Marketing Strategy 2004 (2004 06 09)
16. Transmission Access Strategies and Procedures (2005 10 18)
17. Long Term Transmission Strategy 2006-09 (2006 09 12)
18. Corporate Strategic Plan 2007-08
19. HERMES Application Architecture
20. System Operation Priorities (1988 05 20)
21. Deloitte Presentation on Corporate Risk Management (2004 01 26)
22. Now Is The Time – A Strategic Opportunity (2009 06 19)
23. 2006 Forecast of Generation Costs and Interchange Rev 2006-08 (2006 08 22)
24. 2004 Forecast of Generation Costs and Interchange Rev 2004-2006 (2004 10 08)
25. 2005 Forecast of Generation Costs and Interchange Rev 2005-2007

(2005 08 10)
26. 2006 Forecast of Generation Costs and Interchange Rev 2006-2008 (2006 08 22)
27. 2007 Forecast of Generation Costs and Interchange Rev 2007-2009 (2007 07 27)
28. 2008 Forecast of Generation Costs and Interchange Rev 2008-2010 September Update (2009 08 24)
29. MH Generation Estimate 2005-2006 Actuals
30. MH Generation Estimate 2006-2007 Actuals
31. MH Generation Estimate 2007-2008 Actuals
32. MH 2009-10 Power Resource Plan Full Version (2009 09 16)
33. MH Generation Estimate 2008-09 Actuals
34. MH Generation Estimate 2008-09 Actuals (2009 04 22)

02.03 Organization Charts

01. Power Supply Management Organizational Chart (2009 11 17)
02. Power Sales and Operations Organizational Chart (2009 11)
03. MB Corporate Org Chart Dec 2009
04. Export Power Marketing Organization Chart (2006 12)

02.04 Power Sales

02.04.01 Signing Authority for Power Contracts

01. Approval Authority Table for Power Related Transactions (2008 05 27)
02. Import and Export of Power - Policy G190
03. Items Requiring Approval – MH Corporate Policy G1-4
04. Short Term Sales Quantity Approvals (emails and EMMA reports)
05. POLICY EXCEPTIONS to EPRMC July-Dec 09 (2009 12 23)
06. Approval Authority Table for Power Related Transactions (2007 10 01)

02.04.02 Existing Long Term Contracts

01. Lake St Joseph-Root River Diversion (1958 09 24)
02. Lake St Joseph-Root River Diversion - SOP MO B-15 (1987 09 29)
03. Lake St Joseph-Root River Diversion - SOP MO-B4 (1994 12 20)
04. Lake St Joseph-Root River Diversion - SOP MO-C7 (2001 09 10)
05. Island Falls – SK Power Corp-MH (1985 01 15)
06. Island Falls – SK Power Corp-MH – Amendment (1986 05 30)
07. Island Falls – SK Power Corp-MH (1988 11 28)
08. Diversity Exchange Agreement – NSP-MH (1987 11 16)
09. Diversity Exchange Agreement – NSP-MH – Amendment 1
10. Diversity Exchange Agreement - NSP-MH - Amendment 2 (2008 03 17)
11. NSP Diversity Exchange Agreement – NSP-MH (1991 02 01)
12. NSP Diversity Exchange Agreement – NSP-MH – Amendment 1
13. NSP Diversity Exchange Agreement - NSP-MH - Amendment 2 (2008 03 17)
14. UPA Diversity Exchange Agreement – UPA-MH (1991 02 01)
15. UPA Diversity Exchange Agreement – UPA-MH – Amendment 1
16. UPA Diversity Exchange Agreement - UPA-MH - Supplementary Agreement 2

17. UPA Diversity Exchange Agreement - UPA-MH - Supplementary Agreement 4
18. UPA Diversity Exchange Agreement - UPA-MH - Supplementary Agreement 5
19. UPA Diversity Exchange Agreement - UPA-MH - Supplementary Agreement 7
20. UPA Diversity Exchange Agreement - UPA-MH - Supplementary Agreement 8
21. UPA Diversity Exchange Agreement - UPA-MH - Supplementary Agreement 9
22. UPA Diversity Exchange Agreement - UPA-MH - Supplementary Agreement 10
23. UPA Diversity Exchange Agreement - UPA-MH - Supplementary Agreement 11
24. UPA Diversity Exchange Agreement - UPA-MH - Supplementary Agreement 12
25. UPA Diversity Exchange Agreement - UPA-MH - Supplementary Agreement 13
26. UPA Diversity Exchange Agreement - UPA-MH - Supplementary Agreement 14
27. UPA Diversity Exchange Agreement - UPA-MH - Supplementary Agreement 15
28. UPA Diversity Exchange Agreement - UPA-MH - Supplementary Agreement 16
29. UPA Diversity Exchange Agreement - UPA-MH - Supplementary Agreement 17
30. UPA Diversity Exchange Agreement - UPA-MH - Supplementary Agreement 18
31. UPA Diversity Exchange Agreement - UPA-MH - Supplementary Agreement 18a
32. UPA Diversity Exchange Agreement - UPA-MH - Supplementary Agreement 19
33. UPA Diversity Exchange Agreement - UPA-MH - Supplementary Agreement April 2003
34. UPA Diversity Exchange Agreement - UPA-MH - Supplementary Agreement April 2004
35. Power Sales Agreement – OTP-MH (1999 07 01)
36. Power Sales Agreement - OTP-MH - Supplementary Agreement 1 (2000 05 01)
37. 60-130 MW System Participation Power Sale Agreement – MMPA-MH (2000 01 07)
38. 500 MW System Participation Power Sale Agreement – NSP-MH (2002 08 01)
39. 500 MW System Participation Power Sale Agreement – NSP-MH – Amendment 1
40. 50 MW System Participation Power Sale Agreement – MP-MH (2005 01 06)
41. 50 MW System Participation Power Sale Agreement – MP-MH (2006 06 22)
42. 30 MW System Participation Power Agreement – SMMPA-MH (2007 04 20)

43. 213 MW System Participation Power Sale Agreement - NSP-MH (2007 11 01)
44. 100 MW Energy Sale Agreement - WPSC-MH (2009 05 28)
45. MH Summary of LT Contracts
46. MH Long Term Sales and Purchases Import Export Chart (2009 04 16)
47. Supporting Info for the MP WPS Sales (2010 01 22)
48. KPMG LT Contract Information Request (2010 02 03)
49. LT Contract Information Request 2 (2010 02 16)
50. Total Sales Volume and Average Price By Contract
51. 230 KV Interconnection Coordinating Agreement - MP-NSP-OTP-MHEB (1969 01 16)
52. 230 KV Interconnection Coordinating Agreement - MP-MHEB (1974 12 30)
53. 230 KV Interconnection Coordinating Agreement - MP-MHEB - Supplement No. 7 (1983 03 11)
54. 500 KV Coordination Agreement - NSP-MHEB (1991 02 01)
55. 230 KV Operation Coordinating Agreement - NSP-OTP-MHEB (2002)
56. MISO Coordination Agreement with MH (Public Version) (2009 10 13)
57. MISO Coordination Agreement with MH (Confidential Version) (2009 10 13)
58. Power Supply Proposal for Xcel Energy - Calpine Corporation (2007 02 21)
59. Mankato Pricing Email (2007 09 19)
60. Mankato Pricing Email (2007 09 27)

02.04.03 Short Term Contracts

01. 100 MW System Participation Power Agreement – WPSC-MH (2006 12 15)
02. 30 MW System Participation Power Agreement – MP-MH (2007 04 11)
03. Amendment to 30 MW Return Agreement – WPPI-MH (2007 05 01)
04. 213 MW System Participation Power Sale Agreement – NSP-MH (2007 11 01)
05. Power Sale Transaction Agreement – GRE-MH (2008 03 01)
06. Power Sale Transaction Agreement – GRE-MH (2008 05 01)
07. 50 MW System Participation Energy Sales Agreement – GRE-MH (2008 05 01)
08. 50 MW System Participation Power Agreement – NSP-MH (2008 07 01)
09. 101 MW System Participation Power Sale Agreement – NSP-MH (2008 07 01)
10. 50 MW System Participation Energy Sales Amending Agreement – GRE-MH (2008 08 31)
11. Power Sale Transaction Amending Agreement – GRE-MH (2008 08 31)

02.04.04 Term Sheets

01. Term Sheet – NSP and MH (2006 03)
02. Term Sheet – MP and MH (2007 12)
03. Term Sheet – WPS and MH (2008 03)
04. MHEB Presentation on Proposed New LT Sales (2008 05 21)
05. Tenth Extension to the Term Sheet dated October 31,2006 - NSP-MHEB (2010 01 15)
06. MH Economic Value Provided to NSP
07. Financial Impact of Escalation Commencing May 2006 vs May 2007

02.04.05 Flowcharts

01. Flowchart 1 – Inputs to Buy and Sell Capacity and Energy in MISO Day 2 (2007 05)
02. Flowchart 2 – Buy and Sell Capacity and Energy in the Short-Term Market Place (2007 05)
03. Flowchart 3 – Financial Transmission Rights (FTR) (2007 05)
04. Flowchart 4 – Buy and Sell Capacity and Energy in MISO Day 2 (2007 05)
05. Flowchart 5 – Buy and Sell Capacity and Energy in MISO Day 2 (2007 05)
06. Flowchart 6 – Financial Bilateral Contracts, Financial Deals and Finscheds (2007 05)
07. Flowchart 7 - MISO Day 2 Settlement Process
08. Flowchart 1 – Inputs into Day Ahead Trading Activities (2007 05)
09. Flowchart 2 – Buying and Selling Capacity and Energy in the Short-Term Market (2007 05)
10. Flowchart 3 – Financial Transmission Rights (FTRs) (2007 05)
11. Flowchart 4 – Buy and Sell Capacity and Energy in the MISO (Day 2) Market (2007 05)
12. Flowchart 5 – Obtain transmission, approve tag and enter deal in webTrader (207 05)
13. Flowchart 6 - Financial Bilateral Contract Narrative
14. MISO Day 2 Settlement Process Flowchart Narrative

02.04.06 Miscellaneous

01. Executive Discussion Paper – Export Power Sales Risk Management in MH
02. MH Interoffice Memo – MISO Virtual Bid Offer Strategy (2005 03 29)
03. EY – MH Power Sales and Operations – MISO Day 2 Meeting with the Audit Committee (2006 11 05)
04. PSO – Business Services Department – MISO Settlement Process (2006 05 09)
05. Procedures re MH Hydraulic Enviro Attributes Sold Pursuant to Non-Firm Energy Sales Contracts
06. PSO Resource Planning and Production Scheduling Meeting (2006 10 26)
07. PSO Creditworthiness Requirements Procedures Document (2009 05)
08. PSO New Hydro – Part of the Solution (2009 11 24)

09. PSO Planning Power System Operations (2009 12 11)
10. PSO Opportunity and Merchant Transactions (2009 12 17)
11. Power Sales Risk Management Process (2007 01 12)
12. Order Accepting Coordination Agreement - MISO and MH (2009 12 29)
13. Power Sales Risk Management Process
14. MH Generation Estimate 2009 (10-5) Expected River Flows – TOC
15. MH Generation Estimate 2009 (10-5) Variance Analysis
16. MH Generation Estimate 2009 (10-5) - Sections 4.1.5 to 4.2.2
17. MH Generation Estimate 2009 (10-5) - Sections 4.3 to 4.4
18. Day Ahead Trading Report (2010 01 05)
19. Day Ahead Trading Report (2010 01 06)
20. Opportunity Book Forward Report (2009 12 23)
21. Chart - Merchant Distribution of Total Daily Profits
22. Chart - Merchant Transaction Performance (2009 12 16)
23. Chart - Opportunity Transaction Performance (2009 12 23)
24. Chart - Related Merchant Realized Monthly Profit
25. Related Merchant Realized Monthly Profit
26. Merchant - Return on Investment (2009 12 16)
27. CSOI 2-5.1.0 (2005 06 22)
28. CSOI 3-3.1.3 (2006 05 04)
29. CSOI 3-4.5.0 (2003 11 12)
30. NOP-3214-01 (2009 01 20)
31. NOP-3322-02 (2009 12 30)
32. NOP-3323-10 (2009 05 11)
33. PSO Action Plan - MISO Day 2 Phase 2
34. PSO Action Plan - MISO Day 2 Phase 2 - Update to Items 11 and 12
35. Breakdown of Export Sales Volume by Term (2010 01 19)
36. Potential Energy Supply Relationships for Manitoba Integrated System (2010 01 20)
37. Monthly Reporting Matrix For Extraprovincial Sales and Purchases
38. MH Energy Supply Plans Winter 2003-04 - Cormie (2003 10 01)
39. Opportunity Transactions - Cormie Presentation for PUB (2009 12 17)

02.04.07 Monthly Reports

01.KPMG MHEB MINN HUB DA RT MONTHLY TABLES (2005-2009)
02.Power Sales and Expense Report for November 2009
03.Power Sales and Expense Report for November 2009a
04.PSO Monthly Report for Period Ending December 2009 (final)
05.PSO Monthly Report for Period Ending December 2009 (unfiltered)
06.Management Report (extracts) (2009 11 30)
07.Power Sales and Expense Report for Q2 2009
08.Power Sales and Expense Report for 2005-2009

02.04.08 Financial Reporting Examples

00. PSO Internal Reporting Matrix
00. PSO Reports Index
01. Summary Power Sales and Expense Report
02. Monthly Power Sales and Expense Report

03. Quarterly Power Sales and Expense Report
04. Monthly Activities Report
05. Transaction Performance Report
06. Policy Exceptions Report
07. Management Report
08. Monthly Credit Exposure and Exception Report
09. Day Ahead Trading Report from Power Trading Dept
10. Forecast Generation Costs and Interchange Rev from Hydraulic Ops Dept
11. Power Resource Plan from Resource Planning Dept

02.05 Webtrader

01. Webtrader Power Application Control Review – Internal Audit Report December 2008
02. Webtrader Power System Merchant Trading Process
03. Webtrader Power Real Time Trading Process
04. Webtrader Power Day Ahead Trading Process
05. Webtrader Power Summary of Trading Process
06. Webtrader Power System Interfaces (2006 02 20)
07. Webtrader Market Process and Technology
08. Webtrader System Interfaces and Data Services
09. General description WEBTRADER Interfaces
10. Webtrader Actual Load Architecture
11. Webtrader BSD Monthly Report for December (2009 12)
12. Webtrader BSD Monthly Report for November (2009 11)
13. Webtrader Corridor Flows Architecture
14. Webtrader Deal Capture Screen
15. Webtrader Network Topology (Simplified Version) (2005 01 27)
16. Webtrader Plant Capacity Architecture
17. Webtrader Power Book Structure Diagram
18. Webtrader Power Trading - Process Descriptions
19. Webtrader Regulating Margin Architecture
20. Webtrader SCC NET MW Surplus Architecture
21. Webtrader Weather Architecture
22. Webtrader ZONE Load Forecast Architecture
23. Opportunity Book P&L Daily Report for December 31 2009
24. BSD Sample Monthly Report for November (2009 12 16)
25. PSO Export Activity Diagram (2009 02)
26. Webtrader - Power Settlement, Invoicing and Reporting Process
27. Webtrader - Power Settlement, Invoicing and Reporting - Process Controls
28. Webtrader Power Application Control Review (2008 10)
29. KPMG request webTrader - Entering Deals from off-site
30. WebTrader Enterprise System - Shared Business Practices (2006 02 08)

02.06 Internal Audit

01. MH PSO MISO Day 2 Phase 2 – Power Trading and Settlement Process Follow-up of Phase 1 Audit
02. [Consultant] Report 1 Allegations Schedule Version 2 Oct 15 2009
03. [Consultant] Report 1 Allegations Synopses Schedule

04. [Consultant] Report 2 Allegations Schedule Version 2 Oct 15 2009
05. [Consultant] Report 2 Allegations Synopses Schedule
06. [Consultant] Report 3 Allegations Schedule Version 2 Oct 15 2009
07. [Consultant] Report 3 Allegations Synopses Schedule
08. Consolidated Grouped Summary November 13 2009 File Version
09. MH Internal Audit Terms of Reference

02.07 Miscellaneous

01. Risk Analysis using PRISM (2008 12 16)
02. Corporate Policies – Generation Planning G195
03. System Operations Planning PowerPoint
04. MH Annual Report 2008-09 – excerpts
05. IFF Sequence – Energy Supply and Demand Table
06. MH General Rate Application 2010-2012 (2009 11 30)
07. MH Supply, Demand and Markets (2009 12 11)
08. Future Generation Development in Manitoba
09. Open Access Transmission Tariff Business Practices (2009 06 30)
10. MH General Rate Application Corp Risk Mgmt 2010-2012 (2009 11 30)
11. 11 MH Corporate Policy Statement on Generation Planning (2003 02 07)
12. 12 MH Transmission System Open Access Operations and Reliability Compliance
13. MH IFF 2005-2006 (2005 10)
14. MH IFF 2006-2007 (2007 03)
15. MH IFF 2007-2008 (2007 11)
16. MH IFF 2008-2009 (2008 11)
17. MH IFF 2009-2010 (2009 11)
18. Preliminary Variance Analysis - August 09 vs. IFF O8-01 (2009 09 09)
19. Monthly Management Report - December 2009
20. Net Revenue and Gross Margin Report for 9 months ended Dec (2010 01 29)
21. Statement of Income for 9 months ended Dec - Variance Explanations
22. EPRMC – Risk Summary Update (2010 01 05)
23. MH Energy Resources Review and Outlook (2010 01 20)
24. IFF09 KPMG Drought Analysis File - Expected Prices
25. IFF09 KPMG Drought Analysis File - Expected Prices (Graph)
26. IFF09 KPMG Drought Analysis File - High Prices
27. IFF09 KPMG Drought Analysis File - High Prices (Graph)
28. IFF09 KPMG High Flow Analysis File - Expected Prices
29. MH 20 Year Financial Outlook (2010 01)
30. MH Energy Analysis - February and March 2007
31. KPMG Request 39 - Management Discretion on Forward Price Outlook
32. KPMG Item 40 - Operations Planning (Flow Forecasting)
33. FTR Reconciliation and Settlement Process (2010 02 11)
34. Impact of 5 Year Drought Analysis
35. WPS Levelized Pricing Term Sheet (2007 12 19)
36. MP 250MW Levelized Base Price

37. MP 250 MW Energy Price Adj for Capacity Escalation
38. MP Alternative Price Evaluation
39. 5-Year Drought Impacts on Alternative Development Sequence (2010 02 23)
40. Drought - Base vs Alternate Sequence - Expected Prices
41. Drought - Base vs Alternate Sequence - High Prices
42. Projected Escalation, Interest and Exchange Rates - G911-1 (2009 11 17)
43. EPRMC and PSOMC Meeting Attendance for Don Deviaene and Denise Hickson
44. Executive Committee Minutes (2008 09 30)

02.08 MH Terms of Reference

01. Board – Terms of Reference
02. Audit Committee – Terms of Reference 2006 11 16
03. EPRMC – Terms of Reference
04. Corp Risk Mgmt Steering Committee – Terms of Reference
05. PSOMC Terms of Reference (2005 11 08)
06. PSOMC Terms of Reference Revised (2009 02 10)
07. PRC Terms of Reference
08. EC Terms of Reference
09. MH Internal Audit Department Charter (2008 03 19)

02.09 Policies and Procedures

01. MH Management Control Plan for Power Related Transactions (2007 10 05)
02. Contract Documentation and Review Procedure (2007 11 15)
03. Revisions in Progress – Related Merchant Transactions (2009 01 30)
04. Pricing of Long Term Export Contracts (2009 04 01)
05. Power Sales Risk Policy and Framework (2009 05 21)
06. Summary of Long Term Pricing Forecasts Methodology
07. Summary of Policy Framework and Procedures for Long Term Contract Sales

02.10 Minutes

02.10.01 EPRMC

07-01-12 – EPRMC.01
07-04-04 – EPRMC.02
07-04-11 – EPRMC.03
07-04-24 – EPRMC.04
07-05-09 – EPRMC.05
07-05-23 – EPRMC.06
07-10-05 – EPRMC.07 – Schedule A – MH Management Control Plan
07-10-05 – EPRMC.07
07-10-23 – EPRMC.08
07-11-02 – EPRMC.09 – Schedule A – Export Power Contractual and Legal Risk Policy
07-11-02 – EPRMC.09
08-01-10 – EPRMC.10
08-02-07 – EPRMC.11
08-02-14 – EPRMC.12

08-03-17 – EPRMC.13 – Appendix B
08-03-17 – EPRMC.13
08-06-04 – EPRMC.14
08-10-02 – EPRMC.15
08-10-27 - EPRMC.16 Energy Service Agreement Recommendation
08-10-27 – EPRMC.16
08-11-24 - EPRMC.17 Energy Service Agreement Recommendation
08-11-24 – EPRMC.17
09-02-09 – EPRMC.18
09-06-03 – EPRMC.19
09-09-24 – EPRMC.20
09-10-27 – EPRMC.21
09-11-16 – EPRMC.22
09-11-17 – EPRMC.23

02.10.02 Board

00 KPMG Summary - Board Minutes
03-03-20 - President's Report - March 2003
03-03-20 - Report from Finance and Admin - March 2003
03-12-18-MH Board.bm754
04-01-22-MH Board.bm755
04-02-12-MH Board.bm756
04-03-18-MH Board.bm757
04-05-20-MH Board.bm758
04-06-24-MH Board.bm759
04-08-18-MH Board.bm760
04-09-23-MH Borad.bm761
04-10-21-MH Borad.bm762
04-11-18-MH Board.bm763
05-01-19-MH Board.bm764
05-03-17-MH Board.bm765
05-05-19-MH Board.bm766
05-05-19 - President's Report - May 2005
05-05-19 - Report from Finance and Admin - May 2005
05-06-23-MH Board.bm767
05-08-18-MH Board.bm768
05-09-22-MH Board.bm769
05-10-20-MH Board.bm770
05-11-17-MH Board.bm771
06-01-26-MH Board.bm772
06-03-23-MH Board.bm773
06-05-18-MH Board.bm774
06-06-21-MH Board.bm775
06-08-17-MH Board.bm776
06-09-21-MH Board.bm777
06-10-19-MH Board.bm778
06-11-16-MH Board.bm779
06-11-16 - Board Item Update on Xcel Proposal
06-11-16 - MH Board Minute 779-06-02
06-11-16 - MHEB Presentation - Xcel Energy Provisional Sale

06-11-16 - Report from Power Supply - November 2006
07-01-25-MH Board.bm780
07-01-25 - Report from Power Supply - January 2007
07-03-22-MH Board.bm781
07-03-22 - Report from Power Supply - March 2007
07-05-17-MH Board.bm782
07-05-17 - Report from Power Supply - May 2007
07-06-21-MH Board.bm783
07-06-21 - Report from Power Supply - June 2007
07-06-24-MH Board.bm784
07-08-16-MH Board.bm785
07-08-16 - Report from Power Supply - August 2007
07-09-20-MH Board.bm786
07-09-20 - Report from Power Supply - Septemer 2007
07-10-17-MH Board.bm787
07-11-22-MH Board.bm788
07-11-22 - Report from Power Supply - November 2007
07-11-22 – Board Minute 788 – Recommendation re MH Mgmt Control Plan and Corporate By-Law 5
08-01-23-MH Board.bm789
08-01-23 - Power Supply January Board Report
08-01-23 - Report from Power Supply - January 2008
08-03-20-MH Board.bm790
08-03-20 - Power Supply March Board Report
08-03-20 - Report from Power Supply - March 2008
08-05-22-MH Board.bm791
08-05-22 - MH Board Item - PSA with WPS, MP and NSP
08-05-22 - MH Board Minute 791-08-06
08-05-22 - MHEB Presentation - Proposed Power Sales to Xcel Energy, WPS and MP
08-05-22 - Report from Power Supply - May 2008
08-06-19-MH Board.bm792
08-06-19 - Report from Power Supply - June 2008
08-08-20-MH Board.bm793
08-08-20 - President's Report - August 2008
08-08-20 - Report from Finance and Admin - August 2008
08-08-20 - Report from Power Supply - August 2008
08-09-18-MH Board.bm794
08-09-18 - Report from Power Supply - September 2008
08-10-16-MH Board.bm795
08-10-16 - Report from Power Supply - October 2008
08-11-18-MH Board.bm796
08-11-18 - Report from Power Supply - November 2008
09-01-22-MH Board.bm797
09-01-22 - Report from Power Supply - January 2009
09-03-19-MH Board.bm798
09-03-19 - Report from Power Supply - March 2009
09-05-21-MH Board.bm799
09-05-21 - Report from Power Supply - May 2009
09-06-24-MH Board.bm800
09-06-24 - Report from Power Supply - June 2009

09-08-20-MH Board.bm801
09-08-20 - Report from Power Supply - August 2009
09-09-17-MH Board.bm802
09-09-17 - Report from Power Supply - September 2009
09-10-29-MH Board.bm803
09-10-29 - Report from Power Supply - October 2009
09-11-19-MH Board.bm804
09-11-19 - Report from Power Supply - November 2009
09-11-27-MH Board.bm805

02.10.03 PSOMC

00 KPMG Summary - PSOMC Minutes
2005 03 04 Minutes_Final (Mar 4)
2005 03 16 Minutes_Final (Mar 16)
2005 03 16 April 2005 MISO Monthly Financial Transmission Right Auction Strategy
2005 03 29 Minutes_Final (Mar 29)
2005 04 15 Minutes_Final (Apr 15)
2005 05 16 Minutes_Final (May 16)
2005 05 18 Minutes_Final (May 18)
2005 05 20 Minutes_Final (May 20)
2005 06 02 Minutes_Final (Jun 2)
2005 06 03 Minutes_Final (Jun 3)
2005 06 10 Minutes_Final (Jun 10)
2005 06 16 Minutes_Final (Jun 16)
2005 07 11 Minutes_Final (Jul 11)
2005 07 19 Minutes_Final (Jul 19)
2005 08 02 Minutes_Final rev (Aug 2)
2005 08 04 Minutes_Final (Aug 4)
2005 08 05 Minutes_Final (Augt 5)
2005 08 05 Oct 2005 Yearly IESO Transmission Right Bidding Strategy - Manitoba-Ontario Path
2005 08 12 Minutes_Final (Aug 12)
2005 08 12 Oct 2005 Yearly IESO Transmission Right Bidding Strategy - Minnesota-Ontario Path
2005 08 22 Minutes_Final (Aug 22)
2005 09 06 Minutes_Final (Sep 6)
2005 09 16 Minutes_Final (Sep 16)
2005 10 11 Minutes_Final (Oct 11)
2005 10 18 Minutes_Final (Oct 18)
2005 11 04 Minutes_Final (Nov 4)
2005 11 08 Minutes_Final (Nov 8)
2005 11 15 Minutes_Final (Nov 15)
2005 12 12 Minutes_Final (Dec 12)
2005 12 23 MISO January FTR Auction – Bid Curve Violation
2006 01 18 Minutes_Final (Jan 18)
2006 01 18 Appendix C - Power Supply Approval Authority (2004 12)
2006 02 06 Minutes_Final (Feb 6)
2006 02 15 Minutes_Final (Feb 15)
2006 02 22 Minutes_Final (Feb 22)
2006 03 03 Minutes_Final (Mar 3)

2006 03 07 Minutes_Final (Mar 7)
2006 03 20 Minutes_Final (Mar 20)
2006 04 18 Minutes_Final (Apr 18)
2006 05 09 Minutes_Final (May 9)
2006 05 12 Minutes_Final (May 12)
2006 05 16 Minutes_Final (May 16)
2006 06 13 Minutes_Final (Jun 13)
2006 06 MISO FTR - No Auction Notice (June)
2006 07 18 Minutes_Final (Jul 18)
2006 07 31 Minutes_Final (Jul 31)
2006 08 10 Minutes_Final (Aug 10)
2006 09 18 Minutes_Final (Sept 18)
2006 10 18 Minutes_Final (Oct 18)
2006 11 07 Minutes_Final (Nov 7)
2006 11 15 Minutes_Final (Nov 15)
2006 11 21 Minutes_Final (Nov 21)
2006 12 13 Minutes_Final (Dec 13)
2007 01 19 MISO Feb-2007 Monthly FTR Auction Strategy
2007 02 01 IESO Apr-2007 thru Jun-2007 Monthly and Apr-2007 thru Mar-2008 Yearly TR Bidding Strategies
2007 02 16 MISO Mar-2007 Monthly FTR Auction Strategy
2007 02 22 MISO 2007-2008 Annual FTR Allocation Strategy
2007 03 20 MISO Apr-2007 Monthly FTR Auction Strategy
2007 04 13 MISO May-2007 Monthly FTR Auction Strategy
2007 04 27 MISO 2007-2008 Annual FTR Auction Strategy
2007 05 10 IESO Jul-2007 thru Sep-2007 Monthly and Jul-2007 thru Jun-2008 Yearly TR Bidding Strategies
2007 05 23 MISO Jun-2007 Monthly FTR Auction Strategy
2007 06 13 MISO Jul-2007 Monthly FTR Auction Strategy
2007 07 19 MISO Aug-2007 Monthly FTR Auction Strategy
2007 08 10 IESO Oct-2007 thru Dec-2007 Monthly and Oct-2007 thru Sep-2008 Yearly TR Bidding Strategies
2007 08 17 MISO Sep-2007 Monthly FTR Auction Strategy
2007 09 17 MISO Oct-2007 Monthly FTR Auction Strategy
2007 09 17 Energy Volumes Available for Sale
2007 10 19 MISO Nov-2007 Monthly FTR Auction Strategy
2007 11 15 IESO Jan-08 thru Mar-08 Monthly and Jan-08 thru Dec-08 Yearly TR Bidding Strategies
2007 11 15 MISO Dec-2007 Monthly FTR Auction Strategy
2007 12 17 MISO Jan-08 Monthly FTR Auction Strategy
2008 01 11 MISO Feb 2008 to May 2008 Monthly FTR Auction Strategy
2008 02 12 IESO Apr-08 thru Jun-08 Monthly and Apr-08 thru Mar-09 Yrly TR Bidding Stra
2008 03 13 MISO 2008-2009 Annual Revenue Rights (ARR) Allocation Strategy
2008 05 02 MISO 2008-2009 Annual FTR Auction Strategy
2008 05 13 IESO Jul-08 thru Sep-08 Monthly and Jul-08 thru Jun-09 Yrly TR Bidding Strategies
2008 05 20 MISO Jun-08 Monthly FTR Auction Strategy
2008 06 17 MISO Jul-08 Monthly FTR Auction Strategy

2008 07 17 MISO Aug-08 Monthly FTR Auction Strategy
2008 08 14 IESO Oct 08 - Dec 08 Mthly- Oct 08 - Sep 09 Yrly TR Bidding Strategies
2008 08 14 MISO Sep -08 Monthly FTR Auction Strategy
2008 09 17 MISO Oct-08 Monthly FTR Auction Strategy
2008 10 17 MISO Nov-08 Monthly FTR Auction Strategy
2008 11 13 MISO Dec-08 Jan-09 Feb-09 Monthly FTR Bid Strat. Para.
2008 11 25 IESO Jan 09 - Mar 09 Mthly- Jan 09 - Dec 09 Yrly TR Bid Strat- Parameters
2009 01 20 Environmental Attributes Procedure
2009 02 10 IESO Apr 09 -Jun 09 Mthly - Apr 09 -Mar 2010 Yrly TR Bidding Strat.-Para
2009 02 11 MISO Mar 09 Apr 09 May 09 Monthly FTR Bid Strat.-Para.
2009 02 13 Delgated Authority – Chair
2009 04 13 MISO 2009-2010 Annual FTR Auction Strategy
2009 04 19 Energy Quantities for April-September 2009
2009 05 12 IESO Jul 09- Sep 09 Mthly-Jul 09 - Jun 2010 Yrly TR Bidding StratPara
2009 08 11 - MISO Monthly FTR Acution Strategy and Parameters (Fall Session)
2009 08 11 Energy Quantities for September-December 2009
2009 08 18 IESO Oct. 2009 -Dec. 2009 Mthly- Oct. 2009 - Sept. 2010 Yrly TR Bid Strat.- Para
2009 08 18 Energy Quantities for December 2009 (2x16)
2009 11 12 MISO Monthly FTR Auction Strategy and Parameters (Winter Season)
2009 11 12 Energy Quantities for November 2009 (2x16)
2009 11 17 IESO Jan. 2010-Mar. 2010 mthly-Jan. 2010-Dec. 2010 Yrly TR Bidding Strat.- Para

02.10.04 Audit Committee

00 KPMG Summary - Audit Committee Minutes
04-06-11-Audit Committee.am.17
04-10-13-Audit Committee.am.18
05-03-08-Audit Committee.am.19
05-04-29-Audit Committee.am.20
05-05-18-Audit Committee.am.21
05-05-25-Audit Committee.am.22
05-06-07-Audit Committee.am.23
05-09-22-Audit Committee.am.24
05-10-05-Audit Committee.am.25
05-11-16-Audit Committee.am.26
06-01-12-Audit Committee.am.27
06-04-05-Audit Committee.am.28
06-06-13-Audit Committee.am.29
06-10-11-Audit Committee.am.30
06-11-02-Audit Committee.am.31
07-02-07-Audit Committee.am.32
07-05-09-Audit Committee.am.33
07-06-06-Audit Committee.am.34

07-11-14-Audit Committee.am.35
08-05-08-AUdit Committee.am.36
08-06-05-Audit Committee.am.37
08-11-19-Audit Committee.am.38
09-04-02-Audit Committee.am.39
10-01-27-Audit Committee.am.47

02.10.05 PRC

00 PRC Membership (2005-2010)
06-01-17 - PRC.211 - Agenda_211
06-01-17 - PRC.211 - Jan MHEB Wind Update report
06-01-17 - PRC.211 - Wind Update
06-01-17 - PRC.211
06-03-15 - PRC.212 - Agenda_212
06-03-15 - PRC.212 - Hydro Workforce 2020 CTTC
06-03-15 - PRC.212 - Workforce 2020
06-03-15 - PRC.212
06-04-28 - PRC.213 - 04-05 PSAR PRC FINAL _2_
06-04-28 - PRC.213 - 2006 Electricity Export Price Forecast
06-04-28 - PRC.213 - 2006 Forecast PRC Presentation
06-04-28 - PRC.213 - Agenda_213
06-04-28 - PRC.213 - EcOut06
06-04-28 - PRC.213 - eopres06
06-04-28 - PRC.213 - EPO 2006 Report _Draft to PRC_
06-04-28 - PRC.213 - EPO Presentation - (April 27 2006)
06-04-28 - PRC.213 - PRC Presentation FINAL W.O. NOTES
06-04-28 - PRC.213
06-05-17 - PRC.214 - Agenda_214
06-05-17 - PRC.214 - Fcst2006
06-05-17 - PRC.214 - PRC Pres 2006
06-05-17 - PRC.214
06-07-12 - PRC.215 - 06IFF_prc_2
06-07-12 - PRC.215 - Agenda_215
06-07-12 - PRC.215 - GasFcstDoc2006 Draft
06-07-12 - PRC.215 - PRC Presentation 2006
06-07-12 - PRC.215 - PRP for the 200607 IFF_PRC
06-07-12 - PRC.215
06-08-16 - PRC.216 - 2006 Interchange Revenue Forecast
06-08-16 - PRC.216 - Agenda_216
06-08-16 - PRC.216 - IFF06
06-08-16 - PRC.216 - IFF06_0803
06-08-16 - PRC.216 - REPORT-2006
06-08-16 - PRC.216
06-09-20 - PRC.217 - 2006 Power Smart Plan PRC Sept 20 06
06-09-20 - PRC.217 - Agenda_217
06-09-20 - PRC.217 - Full Report 06Aug23
06-09-20 - PRC.217 - PRC Generation Estimate Sep 20 2006
06-09-20 - PRC.217 - PRC PSP Sept 20 06
06-09-20 - PRC.217
06-10-18 - PRC.218 - Agenda_218
06-10-18 - PRC.218 - IFF06-1 Document - Board Mail Out

06-10-18 - PRC.218 - IFF06 Presentation to PRC
06-10-18 - PRC.218
07-02-01 - PRC.219 - 05-06 PSAR PRC Final
07-02-01 - PRC.219 - 05-06 PSAR Presentation WITHOUT NOTES
07-02-01 - PRC.219 - Agenda_219
07-02-01 - PRC.219 - Brochet Lac Brochet for PRC
07-02-01 - PRC.219 - Preliminary Report - Brochet and Lac Brochet Supply Options
07-02-01 - PRC.219
07-04-18 - PRC.220 - 2007 Economic Outlook
07-04-18 - PRC.220 - 2007 Energy Price Outlook
07-04-18 - PRC.220 - 2007 EPF – PRCversion
07-04-18 - PRC.220 - Agenda_220
07-04-18 - PRC.220 - DOC070419
07-04-18 - PRC.220 - EPO Presentation - (Apr 17, 2007)
07-04-18 - PRC.220 - PRC-2007 Forecast
07-04-18 - PRC.220 - PRC presentation -- Demography recruitment -- v02
07-04-18 - PRC.220
07-05-30 - PRC.221 - Agenda_221
07-05-30 - PRC.221 - Electric Forecast
07-05-30 - PRC.221 - Presentation PRC 2007
07-05-30 - PRC.221
07-07-18 - PRC.222 - 07IFF_prc_3
07-07-18 - PRC.222 - 2007_08 PRP for PRC
07-07-18 - PRC.222 - Agenda_222
07-07-18 - PRC.222 - CKSS_CRW
07-07-18 - PRC.222 - Draft Gas 2007
07-07-18 - PRC.222 - Financial Evaluation of Keeyask Advancement
07-07-18 - PRC.222 - Ken's Questions2
07-07-18 - PRC.222 - PRC Gas Presentation 2007
07-07-18 - PRC.222
07-08-15 - PRC.223 - 2007 Interchange Revenue Forecast
07-08-15 - PRC.223 - Agenda_223
07-08-15 - PRC.223 - IFF07_Aug_08_2007
07-08-15 - PRC.223 - IFF07_Complete_Report_Jul07
07-08-15 - PRC.223 - IFF07_PRC_Aug15
07-08-15 - PRC.223 - PRC Generation Estimate Aug 15 2007
07-08-15 - PRC.223 - REPORT-2007 Aug 1, 2007 Final
07-08-15 - PRC.223
07-09-28 - PRC.224 - Agenda_224
07-09-28 - PRC.224 - Supply Demand Issues 2009 to 2018 Draft
07-09-28 - PRC.224 - Supply Demand Issues, Sept 28 2007 PRC
07-09-28 - PRC.224
07-11-21 - PRC.225 - Agenda_225
07-11-21 - PRC.225 - IFF Document
07-11-21 - PRC.225 - PRC Presentation
07-11-21 - PRC.225 - Preliminary Report - Shamattawa Supply Options
07-11-21 - PRC.225 - Preliminary Report - Tadoule Lake Supply Options
07-11-21 - PRC.225 - Shamattawa and Tadoule Lake PRC presentation

07-11-21 - PRC.225
08-02-20 - PRC.226 - 10_YrPlan_Jan2008
08-02-20 - PRC.226 - 2008 SF Biomass PRC Presentation
08-02-20 - PRC.226 - Agenda_226
08-02-20 - PRC.226 - Historical Evidence of Consumer Demand Response to Long-Term
08-02-20 - PRC.226 - Historical Evidence of Consumer Demand Response
08-02-20 - PRC.226 - Solid Fuel Biomass - Appendices - Volume 2
08-02-20 - PRC.226 - Solid Fuels Biomass Draft Report - Volume 1
08-02-20 - PRC.226 - Ten Year Plan 2008 PRC Presentation
08-02-20 - PRC.226 - Ten Year Transmission Plan 2008 PRC Presentation
08-02-20 - PRC.226
08-04-10 - PRC.227 - 2008 Energy Price Outlook
08-04-10 - PRC.227 - 2008 EO Presentation
08-04-10 - PRC.227 - Agenda_227
08-04-10 - PRC.227 - Economic Outlook
08-04-10 - PRC.227 - EPO Presentation - (April 8, 2008)
08-04-10 - PRC.227
08-04-18 - PRC.228 - 2008 EPF - ECversion – final
08-04-18 - PRC.228 - Agenda_228
08-04-18 - PRC.228 - Final Draft 2008 EPF – PRCversion
08-04-18 - PRC.228 - PRC-2008 Forecast-PRC-Final
08-04-18 - PRC.228
08-05-08 - PRC.229 - 06-07 PSAR Presentation PRC
08-05-08 - PRC.229 - 2006-07 Power Smart Annual Review PRC
08-05-08 - PRC.229 - Agenda_229
08-05-08 - PRC.229
08-05-21 - PRC. 230 - Agenda_230
08-05-21 - PRC. 230 - FcstDoc2008 _ title
08-05-21 - PRC. 230 - Presentation PRC 2008
08-05-21 - PRC. 230
08-07-10 - PRC.231 - Agenda_231
08-07-10 - PRC.231 - GasFcstDoc2008
08-07-10 - PRC.231 - PRC Gas Presentation 2008
08-07-10 - PRC.231
08-07-23 - PRC.232 - 08IFF_prc_0
08-07-23 - PRC.232 - 2008_09PRP_PRC
08-07-23 - PRC.232 - Agenda_232
08-07-23 - PRC.232
08-08-14 - PRC.233 - 2008 Firm Interchange Revenue Report
08-08-14 - PRC.233 - 2008 Generation Estimate
08-08-14 - PRC.233 - 2008 Interchange Revenue Forecast
08-08-14 - PRC.233 - Agenda_233
08-08-14 - PRC.233 - IFF08_PRC_Aug6
08-08-14 - PRC.233 - PRC Generation Estimate Aug 14 2008
08-08-14 - PRC.233 - RPMA_IFF_2008_Aug08
08-08-14 - PRC.233
08-11-13 - PRC.234 - Agenda_234
08-11-13 - PRC.234 - IFF08 Presentation for PRC

08-11-13 - PRC.234 - IFF Document
08-11-13 - PRC.234
09-01-21 - PRC.235 - Agenda_235
09-01-21 - PRC.235 - Marginal Cost PRC January 21 2009
09-01-21 - PRC.235 - Marginal Value Report
09-01-21 - PRC.235 - MarginalCost_PRC
09-01-21 - PRC.235 - MarginalTDCost2004 (Sealed copy)
09-01-21 - PRC.235 - Review of Economic Outlook and Energy Price Outlook Forecast
09-01-21 - PRC.235
09-02-18 - PRC.236 - 10-yrPlan09Feb11pm
09-02-18 - PRC.236 - 2008 Power Smart Plan
09-02-18 - PRC.236 - Agenda_236
09-02-18 - PRC.236 - PRC 2008 02 18 PS Plan
09-02-18 - PRC.236 - Ten Year Plan 2009 PRC Presentation 20090218
09-02-18 - PRC.236
09-03-18 - PRC.237 - Agenda_237
09-03-18 - PRC.237 - Presentation PRC Mar 2009
09-03-18 - PRC.237
09-04-15 - PRC.238 - Agenda_238
09-04-15 - PRC.238 - Draft Economic Outlook 2009
09-04-15 - PRC.238 - Draft Energy Price Outlook 2009
09-04-15 - PRC.238 - eopres09_ESB Comments
09-04-15 - PRC.238 - EPO Presentation - (April 14, 2009)
09-04-15 - PRC.238 - G911
09-04-15 - PRC.238
09-05-20 - PRC.239 - 07-08 PSAR Presentation vFinal
09-05-20 - PRC.239 - Agenda_239
09-05-20 - PRC.239 - DRAFT - Fcst 2009 - May 13
09-05-20 - PRC.239 - MASTER v051909
09-05-20 - PRC.239 - Presentation PRC May 2009
09-05-20 - PRC.239
09-07-08 - PRC.240 - 2009 Power Smart Plan_DRAFT
09-07-08 - PRC.240 - Agenda_240
09-07-08 - PRC.240 - DRAFT - GasFcst2009
09-07-08 - PRC.240 - Gas Forecast PRC Presentation July 8 2009
09-07-08 - PRC.240 - PRC 2009 PSP July 8 09
09-07-08 - PRC.240
09-07-29 - PRC.241 - 09IFF_prc_0
09-07-29 - PRC.241 - Agenda_241
09-07-29 - PRC.241 - Executive Summary Revised - Aug 5 2009 (2)
09-07-29 - PRC.241 - RevisedFinal09PRP_PRC
09-07-29 - PRC.241
09-08-25 - PRC.242 - 2009 Firm Interchange Fcst
09-08-25 - PRC.242 - 2009 Forecast of Generation Costs and Interchange Revenue fo
09-08-25 - PRC.242 - 2009 Interchange Revenue Forecast
09-08-25 - PRC.242 - Agenda_242
09-08-25 - PRC.242 - Gen Est 2009-10 2010-11
09-08-25 - PRC.242 - IFF09_PRC_Aug221
09-08-25 - PRC.242

09-10-21 - PRC.243 - 2009 10 14 Major Facilities Strategy - Power Supply Perspect
09-10-21 - PRC.243 - Agenda_243
09-10-21 - PRC.243 - EES Tech Review to PRC Oct 21 2009 PDF Version
09-10-21 - PRC.243 - Executive Summary Revised - Aug 5 2009
09-10-21 - PRC.243 - Major Facilities Strategy 2009 10
09-10-21 - PRC.243 - Market Update-Oct21-09
09-10-21 - PRC.243
09-12-16 - PRC.244 - 2009 12 16 PRC Generation Attribution Presentation
09-12-16 - PRC.244 - Agenda_244
09-12-16 - PRC.244 - Generation Attribution
09-12-16 - PRC.244 - IFF09 Document
09-12-16 - PRC.244 - IFF PRC Presentation
09-12-16 - PRC.244
10-01-22 - PRC.245 - 08-09 PSAR Presentation vFINAL
10-01-22 - PRC.245 - 2008-09 Power Smart Annual Review – DRAFT
10-01-22 - PRC.245 - Agenda_245
10-01-22 - PRC.245 - PRC Presentation - Weather Normal for Electricity and Natura
10-01-22 - PRC.245
10-02-16 - PRC.246 - Agenda_246

02.11 Risk Management

01. Corporate Risk Management Report June 23 2005(final)
02. Corporate Risk Management Report 2006 draf2
03. Corporate Risk Management Report 2007 2nd draft(2)
04. Corporate Risk Management Report 2008
05. Corporate Risk Management Report Draft (2009 10)
06. MH December 2009 Credit Exposure and Exceptions Review (2010 01 14)
07. Job Description for Senior Risk Management Officer
08. Corporate Risk Management 2009 Long Form CRM Profiles
09. CRM - Terms of Reference
10. CRM – Policy
11. CRM – Objectives
12. CRM – Procedures
13. CRM – Definitions
14. CRM - Corporate Risk Map
15. CRM - Risk Categories
16. CRM - Risk Categories and Responsibility
17. CRM - Risk Criteria Matrix
18. CRM - Risk Profile Templates
19. CRM - Risk Profile Template – Corporate
20. CRM - Risk Profile Template – Divisional
21. CRM - Framework Diagram
22. CRM - Committee Members
23. MH Wholesale Power Risk Policy (2010 02 25)
24. Opportunity Analysis Evaluation and Transaction Approval

02.12 Models

02.12.01 HERMES Model Documentation

01. Hermes Description (2003 05)
02. HERMES Modeling Presentation to KPMG (2010 01 19)
03. Flow Forecasting (2007 02 20)
04. HERMES New Net Export Totals in Capacity rpt Energy rpt
05. HERMES Model Change Tracking Log (2010 01 21)
06. Market Forecast - Second Generation (2008 05 02)
07. CEATI - Hydro System Planning and Operation in Today's Market (2001 11 04)
08. Hydro Scheduling in Competitive Electricity Markets - Oslo (2008 06 09)
09. KPMG Review HERMES Model Documentation Request (2010 01 13)
10. HERMES Market Price Input Assumptions
11. HERMES Lake Level Balances
12. HERMES QSIM Explanation and Usage by Trading
13. MH Explanation of HERMES '_risk' files
14. HERMES Stochastic Modeling

02.12.02 EMMA 2006 Reports to Consultant

06-07-05

05-06 Expected
- availcap
- capacity_risk
- engsum
- flows_risk
- levels
- margin_cost
- pcoeffs.3
- prices_risk

06-07 Expected
- availcap
- capacity_risk
- engsum
- flows_risk
- levels
- margin_cost
- pcoeffs.3
- prices_risk

07-08 Expected
- availcap
- capacity_risk
- engsum
- flows_risk
- levels
- margin_cost
- pcoeffs.3
- prices_risk

06-07-12

05-06 Expected

- availcap
- capacity_risk
- engsum
- flows_risk
- levels
- margin_cost
- pcoeffs.3
- prices_risk

06-07 Expected
- availcap
- capacity_risk
- engsum
- flows_risk
- levels
- margin_cost
- pcoeffs.3
- prices_risk

07-08 Expected
- availcap
- capacity_risk
- engsum
- flows_risk
- levels
- margin_cost
- pcoeffs.3
- prices_risk

06-07-20

05-06 Expected
- availcap
- capacity_risk
- engsum
- flows_risk
- levels
- margin_cost
- pcoeffs.3
- prices_risk

06-07 Expected
- availcap
- capacity_risk
- engsum
- flows_risk
- levels
- margin_cost
- pcoeffs.3
- prices_risk

07-08 Expected
- availcap
- capacity_risk
- engsum
- flows_risk
- levels

    - margin_cost
    - pcoeffs.3
    - prices_risk
- 06-07-27
  - 05-06 Expected
    - availcap
    - capacity_risk
    - engsum
    - flows_risk
    - levels
    - margin_cost
    - pcoeffs.3
    - prices_risk
  - 06-07 Expected
    - availcap
    - capacity_risk
    - engsum
    - flows_risk
    - levels
    - margin_cost
    - pcoeffs.3
    - prices_risk
  - 07-08 Expected
    - availcap
    - capacity_risk
    - engsum
    - flows_risk
    - levels
    - margin_cost
    - pcoeffs.3
    - prices_risk
- 06-08-02
  - 05-06 Expected
    - availcap
    - capacity_risk
    - engsum
    - flows_risk
    - levels
    - margin_cost
    - pcoeffs.3
    - prices_risk
  - 06-07 Expected
    - availcap
    - capacity_risk
    - engsum
    - flows_risk
    - levels
    - margin_cost
    - pcoeffs.3
    - prices_risk
  - 07-08 Expected

- availcap
  - capacity_risk
  - engsum
  - flows_risk
  - levels
  - margin_cost
  - pcoeffs.3
  - prices_risk

06-08-23

- 05-06 Expected
  - availcap
  - capacity_risk
  - engsum
  - flows_risk
  - levels
  - margin_cost
  - pcoeffs.3
  - prices_risk
- 06-07 Expected
  - availcap
  - capacity_risk
  - engsum
  - flows_risk
  - levels
  - margin_cost
  - pcoeffs.3
  - prices_risk
- 07-08 Expected
  - availcap
  - capacity_risk
  - engsum
  - flows_risk
  - levels
  - margin_cost
  - pcoeffs.3
  - prices_risk

06-08-30

- 05-06 Expected
  - availcap
  - capacity_risk
  - engsum
  - flows_risk
  - levels
  - margin_cost
  - pcoeffs.3
  - prices_risk
- 06-07 Expected
  - availcap
  - capacity_risk
  - engsum
  - flows_risk

- levels
- margin_cost
- pcoeffs.3
- prices_risk

07-08 Expected
- availcap
- capacity_risk
- engsum
- flows_risk
- levels
- margin_cost
- pcoeffs.3
- prices_risk

06-09-07

05-06 Expected
- availcap
- capacity_risk
- engsum
- flows_risk
- levels
- margin_cost
- pcoeffs.3
- prices_risk

06-07 Expected
- availcap
- capacity_risk
- engsum
- flows_risk
- levels
- margin_cost
- pcoeffs.3
- prices_risk

07-08 Expected
- availcap
- capacity_risk
- engsum
- flows_risk
- levels
- margin_cost
- pcoeffs.3
- prices_risk

06-09-13

05-06 Expected
- availcap
- capacity_risk
- engsum
- flows_risk
- levels
- margin_cost
- pcoeffs.3
- prices_risk

- 06-07 Expected
    - availcap
    - capacity_risk
    - engsum
    - flows_risk
    - levels
    - margin_cost
    - pcoeffs.3
    - prices_risk
- 07-08 Expected
    - availcap
    - capacity_risk
    - engsum
    - flows_risk
    - levels
    - margin_cost
    - pcoeffs.3
    - prices_risk

06-09-20

- 05-06 Expected
    - availcap
    - capacity_risk
    - engsum
    - flows_risk
    - levels
    - margin_cost
    - pcoeffs.3
    - prices_risk
- 06-07 Expected
    - availcap
    - capacity_risk
    - engsum
    - flows_risk
    - levels
    - margin_cost
    - pcoeffs.3
    - prices_risk
- 07-08 Expected
    - availcap
    - capacity_risk
    - engsum
    - flows_risk
    - levels
    - margin_cost
    - pcoeffs.3
    - prices_risk

06-09-27

- 05-06 Expected
    - availcap
    - capacity_risk
    - engsum

- flows_risk
- levels
- margin_cost
- pcoeffs.3
- prices_risk

06-07 Expected

- availcap
- capacity_risk
- engsum
- flows_risk
- levels
- margin_cost
- pcoeffs.3
- prices_risk

07-08 Expected

- availcap
- capacity_risk
- engsum
- flows_risk
- levels
- margin_cost
- pcoeffs.3
- prices_risk

06-10-05

05-06 Expected

- availcap
- capacity_risk
- engsum
- flows_risk
- levels
- margin_cost
- pcoeffs.3
- prices_risk

06-07 Expected

- availcap
- capacity_risk
- engsum
- flows_risk
- levels
- margin_cost
- pcoeffs.3
- prices_risk

07-08 Expected

- availcap
- capacity_risk
- engsum
- flows_risk
- levels
- margin_cost
- pcoeffs.3
- prices_risk

- 06-10-19
  - 05-06 Expected
    - availcap
    - capacity_risk
    - engsum
    - flows_risk
    - levels
    - margin_cost
    - prices_risk
  - 06-07 Expected
    - availcap
    - capacity_risk
    - engsum
    - flows_risk
    - levels
    - margin_cost
    - prices_risk
  - 07-08 Expected
    - availcap
    - capacity_risk
    - engsum
    - flows_risk
    - levels
    - margin_cost
    - prices_risk
- 06-10-25
  - 05-06 Expected
    - availcap
    - capacity_risk
    - engsum
    - flows_risk
    - levels
    - margin_cost
    - prices_risk
  - 06-07 Expected
    - availcap
    - capacity_risk
    - engsum
    - flows_risk
    - levels
    - margin_cost
    - prices_risk
  - 07-08 Expected
    - availcap
    - capacity_risk
    - engsum
    - flows_risk
    - levels
    - margin_cost
    - prices_risk
- 06-11-02

- 05-06 Expected
  - availcap
  - capacity_risk
  - engsum
  - flows_risk
  - levels
  - margin_cost
  - prices_risk
- 06-07 Expected
  - availcap
  - capacity_risk
  - engsum
  - flows_risk
  - levels
  - margin_cost
  - prices_risk
- 07-08 Expected
  - availcap
  - capacity_risk
  - engsum
  - flows_risk
  - levels
  - margin_cost
  - prices_risk

06-12-01

- 05-06 Expected
  - availcap
  - capacity_risk
  - engsum
  - flows_risk
  - levels
  - margin_cost
  - prices_risk
- 06-07 Expected
  - availcap
  - capacity_risk
  - engsum
  - flows_risk
  - levels
  - margin_cost
  - prices_risk
- 07-08 Expected
  - availcap
  - capacity_risk
  - engsum
  - flows_risk
  - levels
  - margin_cost
  - prices_risk

02.12.03 Miscellaneous

- 05-06 Expected
  - availcap
  - capacity_risk
  - engsum
  - flows_risk
  - levels
  - margin_cost
  - prices_risk
- 06-07 Expected
  - availcap
  - capacity_risk
  - engsum
  - flows_risk
  - levels
  - margin_cost
  - prices_risk
- 07-08 Expected
  - availcap
  - capacity_risk
  - engsum
  - flows_risk
  - levels
  - margin_cost
  - prices_risk

06-12-01

- 05-06 Expected
  - availcap
  - capacity_risk
  - engsum
  - flows_risk
  - levels
  - margin_cost
  - prices_risk
- 06-07 Expected
  - availcap
  - capacity_risk
  - engsum
  - flows_risk
  - levels
  - margin_cost
  - prices_risk
- 07-08 Expected
  - availcap
  - capacity_risk
  - engsum
  - flows_risk
  - levels
  - margin_cost
  - prices_risk

02.12.03 Miscellaneous

01. SPLASH-HERMES PROD COEFFS
02. PUB Filing on Drought Impact
03. RPMA Data Summary A4AF2 2016 Text
04. Typical SPLASH Output
05. Current Decision Making Process
06. Generation Estimate Historical Variance Summary 1999-2009 (mid-year updates)
07. Monthly Historical Potential Energy Supply
08. Excerpt from EMMA Capacity Reporting (2006 02 09)
09. EMMA Reports 2006-2007 - Year 2 Generation Estimate (2006 08 14)
10. EMMA Reports - 2006-2007 Generation Estimate Year 1 (2006 08 21)
11. Price Reconciliation Between 'prices_risk' and Gen Est Reports
12. Eastern Grid - ERCOT Market Forecast (2003 07 31)
13. Eastern Grid - ERCOT Market Forecast (2004 07 30)
14. Eastern Grid - ERCOT Market Forecast (2005 07 29)
15. Eastern Grid - ERCOT Market Forecast (2006 07 31)
16. Eastern Grid - ERCOT Market Forecast (2007 07 03)
17. Eastern Grid - ERCOT Market Forecast (2008 07 07)
18. Eastern Grid - ERCOT Market Forecast (2009 07 10)
19. Hydraulic Supply Estimator_20100303 version
20. Report on Drought Flow Analysis for Contract Project G132 (1998 08 31)
21. Economic and Financial Impacts of Changes to MH's Water Supply From Climate Change (2004 08 24)
22. COALITION-MH I-43(e) (2007 12 07)

02.12.04 SPLASH Model Documentation

01. KPMG SPLASH Model Data Request (2010 01 29)
02. An Introduction to the SPLASH Model (2009 08 31)
03. Proposal for Generation Planning System (1990 02 25)
04. SPLASH Input Tables (2010 01 18)
05. SPLASH Output Tables (2010 01 18)
06. SPLASH Market Representation Presentation (2010 03 05)

02.12.05 Lake Level Coefficients and Storage Relationships

00 Lake Production Coefficient
Ball Lake
Cedar Lake
Cross Lake
Great Falls Forebay
Jenpeg Forebay
Kelsey Forebay
Lac du Bonnet
Lac la Croix
Lac Seul
Lake of the Woods
Lake St. Joseph
Lake Winnipeg
Laurie River Forebay

Limestone Forebay
Long Spruce Forebay
Namakan Lake
Natalie Lake
Pakwash Lake
Pine Falls Forebay
Pointe du Bois Forebay
Rainy Lake
Sand Lake
Separation Lake
Sipiwesk Lake
Slave Falls Forebay
Southern Indian Lake
Split Lake
Stephens Lake
Thompson Seaplane Base
Umfreville Lake

02.12.06 EMMA Flow Reports
00 Historic Flow Record 1912-2006
flows_1977
flows_1978
flows_1979
flows_1980
flows_1981
flows_1982
flows_1983
flows_1984
flows_1985
flows_1986
flows_1987
flows_1988
flows_1989
flows_1990
flows_1991
flows_1992
flows_1993
flows_1994
flows_1995
flows_1996
flows_1997
flows_1998
flows_1999
flows_2000
flows_2001
flows_2002
flows_2003
flows_2004
flows_2005
flows_2006
flows_2007

flows_2008

02.12.07 EMMA Sensitivity Analysis

01. KPMG Request 52 - EMMA Sensitivity Analysis on Market Forecast
02. PIRA Forecast and Actual 2007-08 (for EMMA Sensitivity Analysis)
03. Generation Estimate 2010-11 Lake Winnipeg - 712.0ft_actual_price_q_median
04. Generation Estimate 2010-11 Lake Winnipeg - 712.0ft_forecast_price_q_median
05. Fixed_Path_712 0_end_elev
06. 712.0_end_elev
07. Generation Estimate 2010-11 Lake Winnipeg - 713.1ft_actual_price_q_median
08. Generation Estimate 2010-11 Lake Winnipeg - 713.1ft_forecast_price_q_median
09. Fixed_Path_713 1_end_elev
10. 713.1_end_elev
11. Generation Estimate 2010-11 Lake Winnipeg - 714.2ft_actual_price_q_median
12. Generation Estimate 2010-11 Lake Winnipeg - 714.2ft_forecast_price_q_median
13. Test_actual_price_714 2_end_elev
14. Fixed_Path_714 2_end_elev
15. 714.2_end_elev
16. EMMA Sensitivity Analysis Results (original)
17. EMMA Sensitivity Analysis to Price Forecast Results Summary

02.13 MH Credit

01. Manitoba Hydro Creditworthiness Requirements (2001 05 31)
02. October 2006 Credit Exposure and Exceptions Review (2006 11 20)
03. Wholesale Power Transactions Credit Report for Quarter (2006 12 31)
04. Wholesale Power Transactions Credit Report for Quarter (2009 06 30)
05. December 2009 Credit Exposure and Exceptions Review (2010 01 14)

02.14 Monthly Management Reports

01. Monthly Management Report - September 2008
02. Monthly Management Report - November 2008
03. Monthly Management Report - December 2008
04. Monthly Management Report - January 2009
05. Monthly Management Report - February 2009
06. Monthly Management Report - March 2009
07. Monthly Management Report - May 2009
08. Monthly Management Report - June 2009
09. Monthly Management Report - July 2009
10. Monthly Management Report - August 2009
11. Monthly Management Report - September 2009
12. Monthly Management Report - October 2009
13. Monthly Management Report - November 2009
14. Monthly Management Report - December 2009

02.15 Weather Derivative Correspondence

01. Fw Manitoba Hydro (2005 09 26)
02. RE Alternative Risk Transfer (2005 10 11)
03. RE Alternative Risk Transfer (2005 10 11) (2)
04. Fw Manitoba Hydro - Alternative Risk Transfer Meeting (2005 10 16)
05. Re Manitoba Hydro (2005 10 21)
06. Re Manitoba Hydro (2005 10 21) (2)
07. RE Drought Insurance Hypothetical Quotation (2005 11 01)
08. Re Manitoba Hydro - tentative pricing (2005 11 18)
09. Thank you (2007 07 24)

rd Party Reports

01. Report on Risks Faced by MH in Power Exports – Bhattacharyya – Summary Version (2007 07 04)
02. Report on Risks Faced by MH in Power Exports – Bhattacharyya – Full Version (2007 07 04)
03. Drought Risk Management Review 2002-2004 – Risk Advisory A Division of SAS (2005 01 18)
04. PSO Division – Trading and Risk Management Org Structure – Risk Advisory A Division of SAS (2005 05 25)
05. ICF Report – Unredacted Version
06. ICF Report – Redacted Version
07. Recommendations and Summary of ICF Report
08. Qualifications of ICF Consulting
09. Peer Review of Manitoba Hydro's SPLASH Model – Government of Manitoba (2005 05)
10. Report on SPLASH Model – Slobodan P. Simonovic Consulting Ltd. (2005 05 05)
11. Review of MH's SPLASH Model – Doering Engineering Inc. (2005 05 25)
12. Summary of SPLASH Model Peer Review – KGS Group (2005 05 20)
13. Risk Management Review of PSO – Risk Advisory (2003 04 01)
14. OECM – Risk Assessment and Business Planning Workshop (2007 03 21)
15. OECM Risk Assessment Report (2007 04 30)
16. National Public Finance Guarantee – Public Power Sector Study
17. MISO Market Concepts Study Guide 092304
18. Counsel's Argument on behalf of BC Hydro's 2006 IEP and Long-Term Acquisition Plan (2007 02 02)
19. Electric Power Generation Transmission and Distribution – 2002
20. Electric Power Generation Transmission and Distribution – 2003
21. Electric Power Generation Transmission and Distribution – 2004
22. Electric Power Generation Transmission and Distribution – 2005
23. Electric Power Generation Transmission and Distribution – 2006
24. Electric Power Generation Transmission and Distribution – 2007
25. Long-Term Risk Management for Utility Companies - The Next Challenges (2009 09 23)
26. Risks in Power Exports – Bhattacharyya
27. Short-Term Generation and Transaction Scheduling at MH using the Vista Decision Support System

D

Appendix D-1: KPMG Review of the Consultant's December 4, 2006 Report

The Phase 2 references in the attached sheets correspond to the Themes and Issues presented in the following table:

Themes and Issues		
1. Forecasting models		
1.1	Appropriateness of inputs and model logic relating to	
	1.1.1	Pricing
	1.1.2	Water volume
	1.1.3	Key model parameters
	1.1.4	Lake water level balances
	1.1.5	Market rules.
1.2	Treatment of optionality	
	1.2.1	Plant cycling
	1.2.2	Storage.
1.3	Validation of models	
2. Power sales management		
2.1	Pricing methodology for firm power sales	
2.2	Risk capital reserves	
2.3	Long-term contracts structure.	
3. Risk governance		
3.1	Independence of the Middle Office function	
3.2	Resourcing and authorities relating to energy risk management.	
4. Power risk management		
4.1	Treatment of risk (identification, measurement, treatment)	

APPENDIX D

THE BALANCE OF THIS KPMG APPENDIX HAS BEEN REDACTED (as proposed by the NYC) IN ACCORDANCE WITH THE PUB'S ORDER ON REDACTIONS OF RISK REPORTS

E

Appendix E: Case Studies Review

KPMG conducted research on other electric utilities, through a series of case studies, to provide additional contextual information in the conduct of our work. The purpose of the case study review was to obtain current industry comparables and review how other electric utilities have adjusted and implemented strategies to adapt to changing market conditions.

The interview questions were based on the themes addressed by KPMG's report, specifically risk governance, power risk management, power sales management and forecasting models. In addition, background information on each utility was collected in order to understand the context in which it operates. The case studies were done to provide additional contextual information regarding the direction and activities of other electric utilities in areas appropriate to the issues.

The information collected on each utility was primarily from publicly available information as well as a telephone interview with a representative(s) designated by each utility.

In order to identify comparable electric utilities for inclusion in our review a set of selection criteria were outlined. Selection criteria included meeting a few or more of the following:

- considerable hydro power generation;
- government ownership;
- participation in power markets;
- geographic relevance;
- comparable size; and
- applicability along at least one of the themes being addressed.

Electric utilities were identified from KPMG's professional experience, input from Manitoba Hydro, industry research and then the selection criteria were applied. Our focus was North America, reviewing key Canadian electric utilities and a geographic mix of U.S. and international companies that met at least a few of the selection criteria.

In total, 14 electric utilities were reviewed, five in Canada, seven in the United States, and two international hydro-based utilities, one in South America and one in New Zealand.

The following electric utilities were reviewed:

- *Canada*:
  - B.C. Hydro
  - Emera (includes Nova Scotia Power)
  - Hydro Quebec
  - Nalcor (includes Newfoundland & Labrador Power)
  - Ontario Power Generation
- *United States:*
  - Tennessee Valley Authority
  - Bonneville Power Administration
  - Salt River Project
  - New York Power Authority
  - Puget Energy
  - Lower Colorado River Authority
  - Hoover Dam (U.S. Department of the Reclamation)
- *International:*
  - Endesa Chile
  - Meridian Energy (New Zealand)

The following chart provides an overview of the 14 electric utilities reviewed.

Overview Information on Electric Utilities Reviewed					
	Location	Latest Annual Revenues	Installed Capacity	% Hydro Generation	Ownership
B.C. Hydro	Vancouver, BC, Canada	CDN $4.3 billion	11,330 MW	94%	Government
Hydro Quebec	Montreal, PQ, Canada	CDN $12.7 billion	34,429 MW	94%	Government
Ontario Power Generation	Toronto, ON, Canada	CDN $5.6 billion	21,748 MW	32%	Government
Nalcor Energy	St. John's, NL, Canada	CDN $0.6 billion	7,307 MW	97%	Government
Emera Inc.	Halifax, NS, Canada	CDN $1.3 billion	3,038 MW	33%	Publicly traded
Tennessee Valley Authority	Knoxville, TN, USA	US $11.3 billion	33,716 MW	8%	Government
New York Power Authority	White Plains, NY, USA	US$3.2 billion	6,846 MW	74%	Government
Lower Colorado River Authority	Austin, TX, USA	US $1.3 billion	3,400 MW	2%	Government
Puget Sound Energy	Bellevue, WA, USA	US $3.3 billion	2,926 MW	8%	Private
Salt River Project	Tempe, AZ, USA	US $2.7 billion	8,094 MW	5%	Government
Bonneville Power Authority	Portland, OR, USA	US $2.9 billion	13,485 MW	89%	Government
Hoover Dam (US Bureau of Reclamation)	Denver, CO, USA	n/a	14,859 MW	100%	Government
Endesa Chile	Santiago, Chile	US $3.9 billion	13,298 MW	62%	Publicly traded
Meridian Energy	Wellington, New Zealand	US $1.2 billion	2,693 MW	96%	Government

Manitoba Hydro's CEO sent a letter to each of the identified electric utilities noting that KPMG is conducting an independent review on Manitoba Hydro's risk management practices and requesting that they identify an appropriate representative to participate in a telephone interview with KPMG. KPMG then scheduled an interview with the identified representative, typically from their risk management group, middle office or finance department.

Interview questions were structured within each of the four themes. Where we already had information from publically available sources, questions and time were more focused in other areas. The questions are outlined below.

Interview Questions

Risk Governance

- Please describe the risk governance structure related to power sales and supply. In doing so, please address: committee structure, delegation of authorities, decision making bodies and approval structures.
- How has this structure evolved over the last five years?
- How is your middle office organized, in terms of reporting relationships?
- How many people work in the middle office?
- Describe the role and responsibilities of the middle office in terms of operational oversight, compliance monitoring, approvals processes and reporting.
- Does the middle office have a role in auditing or verifying forecasting models that are used in sales and operational areas?

- What information technology systems are used by the middle office?
- How does the middle office interact with the CFO and/or the Chief Risk Officer (or equivalent)?
- What assurance or independent reviews take place for the middle office? Who conducts the reviews? (e.g., internal audit, external audit, independent reviews by specialized consultants)
- How has the middle office evolved over the last five years?

Power Risk Management

- Do you have a defined process in place to identify risks? Do you have documented definitions of your inherent risks?
- Do you have risk limits to control market, credit and liquidity exposures? If so, can you specify the types of limits in place (e.g., stop loss limits, volume limits, tenor limits, concentration limits, counterparty limits)?
- What risk analytic methods (e.g., VaR, stress testing, scenario analysis) do you employ to measure market risk, credit risk, volume risk?
- What applications (i.e., software) do you use to calculate exposures? What is your system of record?
- What is the process to identify and manage inherent risks associated with prospective commodity deals and hedging strategies?
- Do you purchase weather insurance/derivatives?
- Can you list the types and production frequency of risk reports? Who or what function produces and sees the risk reports?
- How has this evolved over the last five years? What caused any changes?

Power Sales Management

- Do you enter into long-term firm power sales contracts greater than five years? What is the average term of the long-term contracts?
- Is contract price based on current market price or a fixed price with escalator provisions?
- If fixed price with escalator, what is the escalator provision?

- What is the approximate percentage of total power sales between short-term sales and long-term firm sales, has this percentage allocation changed over the last five years, if so, why?
- What is the process for originating contracts? Determining the price of the contracts? Is there an independent office that checks the terms/price?
- What is the approval process for contracts? What documentation/analysis is required for approval?

Modeling

- How much historical information do you have on water flows for the watersheds covered by your hydroelectric generation facilities?
- Do you consider the potential for water flows worse than the historical record in your planning process? (e.g., "Black Swan" events?)
- In planning for drought events, do you target a particular probability level, simply plan to address the worst drought event on record, or something else?
- Do you take into account the potential for climate change to impact future water flows in your forecasting/planning processes?
- What sources of risk or uncertainty are taken into account in your planning and operational models?
- What is the nature of the models used for planning and for operation of your hydroelectric system and associated storage capacity?
- How many staff are dedicated to modeling?
- Are your models developed in-house or external?
- Is your price forecasting data internal or external?
- Do you have corporate policies with respect to model documentation?
- What role do internal audit and/or risk management play in the development or validation of models?
- Have there been significant changes in modeling approaches and concepts over the last five years?

The following case studies provide an outline of our findings for each electric utility we reviewed. The case studies include:

- **Corporate Overview** – key financial and operational indicators, corporate strategy, ownership, regulatory relationship and other information.

- **Risk Governance** – an overview of their risk governance at the Board, executive and staff levels, and a discussion of middle office functions.

- **Power Risk Management** – an overview of risk management policy, risk identification, measurement and reporting, as well as commodity price risk, derivatives and hedging strategies.

- **Power Sales Management** – general information on long-term contracts if applicable and available.

- **Forecasting Models** – overview of hydrological modeling approach and the types of models used if available.

1. Corporate Overview

Company Address/Key Contacts

British Columbia Hydro & Power Authority
333 Dunsmuir Street
Vancouver, BC V6B 5R3 Canada
(604) 224-9376
www.bchydro.com

Financial Snapshot ($CDN)

Latest Fiscal Year:	March 2009	**Long-Term Debt:**	$9,135 million
Revenue:	$4,269 million	**Equity:**	$2,189 million
Domestic Revenues:	$2,814 million	**Debt to Equity:**	81:19
Export/Trade Revenue:	$1,455 million	**Return on Equity:**	11.75%
Net Income:	$366 million	**Total Assets:**	$16,368 million
Fiscal Year End:	March	*Source: BC Hydro 2009 Annual Report*	
Employees:	5,844 (March 31, 2009)		

Generation Capacity

Installed Capacity:	11,330 MW
Generation:	43,000 to 54,000 GWh 45,894 GWh in 2009
Mix:	Hydro 94% Thermal 6%
Sites:	80 generating units at 31 hydroelectric facilities 9 generating units at 3 thermal plants

- Also, under the 1964 Columbia River Treaty with the U.S. that resulted in construction of three dams for flood control and hydroelectricity, Canada receives one-half of the extra power produced in the U.S. This entitlement is owned by the Province of B.C. and administered by BC Hydro. This amount varies yearly, but is generally in the range of 4,400 GWh per year and about 1,250 MW of capacity.

Source: BC Hydro 2009 Annual Report

Transmission

- BC Transmission Corporation established as a new Crown Corporation in 2003 to maintain and operate BC Hydro's transmission assets.
- Interconnected system of 18,531 km of transmission lines and 56,780 km of distributed lines owned by 1.8 million customers, 1.6 million residential.

Company Overview

- Integrated electric utility company, generator and distributor of electricity
- Largest electric utility company in the province
- One of North America's leading produces of clean, renewable hydroelectric power

Ownership/Subsidiaries

- Government-owned Crown Corporation
- Province of British Columbia, *Hydro and Power Authority Act* provides BC Hydro's mandate
- BC Hydro also operates through its subsidiaries: Powerex Corp, Powertech Labs Inc., BCH Services Asset Corp and Columbia Hydro Constructions Ltd.
- Powerex participates in electricity and natural gas trading and marketing throughout North America.

Mandate and Core Strategy

- Purpose is to provide "reliable power, at low cost, for generations"
- Mandate is to generate, purchase, distribute and sell power and meet the need in BC in a cost effective and reliable manner.
- BC Hydro's core strategy is to conserve, build and buy to provide the electricity British Columbians need.

Demand Side Management

- The demand-side management plan has a three-prong approach to energy conservation, anticipating roughly one-half of the electricity savings coming from Power Smart programs, 30% from government codes and standards and 20% from conservation rate structures.
- During the last year, Power Smart programs produced cumulative energy savings of 983 GWh (equivalent to powering over 65,000 homes a year), an increase of 657 GWh over fiscal 2008.

From BC Hydro 2009 Annual Report

Regulatory and Planning Framework

Regulator:
- British Columbia Utilities Commission (BCUC)

Planning:
- The BCUC must approve rates charged by BC Hydro
- Plans are guided by the Province's *2007 BC Energy Plan*
- Critical energy planning is embedded in BC Hydro's Long-Term Acquisition Plan (LTAP) filed under the regulator.
- The LTAP sets out forecasted energy requirements for the next 10 years.
- The LTAP is a long-term integrated resource plan and both a primary driver in BC Hydro's business processes and a regulatory requirement.
- One of the targets is self-sufficiency in energy and capacity by 2016
- Other main target is to meet at least 50 percent of incremental resource needs through demand-side (conservation) management by 2020
- B.C. is part of the Western Electricity Coordinating Council (WECC), along with Alberta and western U.S. states.

Environmental - Emissions

BC Energy Plan:

- Ensuring all new electricity projects have zero net greenhouse gas emissions and clear or renewable electricity continues to account for at least 90% of total generation
- BC Hydro operates at one of the lowest carbon intensities in the world.
- Greenhouse gas emission reduction targets have been established. One target is zero greenhouse gas emissions from existing thermal plants by 2016.
- In 2009, BC Hydro introduced a more modern Environmental Risk Management and Regulatory Framework that provides a consistent structured approach to Environmental Risk Assessment (*BC Hydro 2009 Annual Report*, p.48).

2. Risk Governance

Risk Governance

- Risk governance is part of the Audit and Risk Management Committee of the Board of Directors, and at a management level, the corporate Risk Management Committee. The CRO leads the RMC meetings.
- BC Hydro has a Chief Risk Officer. According to the organizational chart, the CRO reports to Executive Management through Chief Safety, Health & Environment Officer and the CFO. The CRO covers the entire organization and subsidiaries and sits on the Risk Management Committees of both BC Hydro and Powerex. The CFO of BC Hydro and CEO of Powerex also sit on both RMCs.
- Understanding is that the Risk Management Committees and Risk Management structure were established about four years ago as a move towards enterprise risk management. Risks are constantly evolving in a hydro system.

From BC Hydro Board Governance Manual:

- As part of its mandate, BC Hydro's Audit and Risk Management Committee reviews the management of principal risks not identified as the responsibility of other committees of the Board of Directors. This committee is the lead committee for ensuring systems are in place to identify, manage and monitor principal risks.
- The CEO and CFO, with advice from the Chief Risk Officer and the corporate Risk Management Committee are responsible for establishing processes, procedures and mechanisms to identify risk and ensure strategies are developed to manage such risks. This includes risks of low probability and high impact events.
- The Board Committee receives quarterly reports from the corporate Risk Management Committee.
- Powerex, the energy trading subsidiary, has its own board consisting of members of the BC Hydro Board plus BC Hydro's CEO, as well as its own Audit and Risk Management Committee. The CEO of Powerex reports to the CEO of BC Hydro.
- *From Powerex Policies and Codes:* Risk management at Powerex consists of three components – the Powerex Risk Management Governance Framework, the Powerex Risk Management Policy and the Powerex Risk Management Procedures. In addition to corporate codes of conduct, Powerex traders are governed by a Trading Code of Conduct.

Key Risks

From BC Hydro 2009 Annual Report, pgs. 72-75:

- The key risks BC Hydro faces are divided into six categories for management purposes: employee, public and dam safety; reliability; financial performance; regulatory; organizational risk; and environmental.

- In meeting its financial performance targets, BC Hydro faces many risks including energy costs, energy demand, interest and foreign exchange rates, pension obligations, and energy trading.

- Of these, risks associated with energy costs – specifically water inflows and energy market prices – are the largest. Energy cost risk is the most significant financial risk to BC Hydro. BC Hydro manages energy cost risk through its flexible hydroelectric system which allows water to be stored in large reservoirs and used when it is most economic, and by hedging the cost of imported electricity. This risk is also mitigated through regulatory deferral accounts which allow BC Hydro to recover its energy costs in rates provided they have been prudently incurred.

- BC Hydro's energy trading subsidiary, Powerex, is exposed to market price risk and counterparty obligation risk. Powerex manages these risks by operating through defined limits that are regularly reviewed by both the Powerex and BC Hydro Board of Directors. Powerex primarily focuses on near-mid-term trading positions, backing forward commitments with the physical supply capability of the BC Hydro system, the Canadian Entitlement, and other supply contracts, operating within Board-approved market and credit risks. Longer term positions are reviewed in the context of the overall energy trading portfolio.

Middle Office

- Powerex is organized into a front office (trading staff), middle office (transactions oversight, risk and credit management, risk reporting) and back office (accounting).
- Approximately 10 personnel work in the Middle Office that includes the Director of Risk and a group of risk analysts and a group covering trade record control. There is also a credit group. The Director of Risk reports to the CEO and is a member of Powerex's Executive Committee.
- For recording of transactions, Powerex uses the ZaiNet (SunGard product) risk management and energy trading system. The policy requires that all transmissions must be recorded in the system. Powerex's positions (long, short and open) are maintained by the middle office.
- The policy sets certain daily, weekly and monthly obligations for reporting to staff, managers and to the Risk Management Committee. Reports include positions summaries, mark-to-market, profit and loss, and risk measures such as VaR. The middle office generates the reports. Any significant risk management issues, including exceptions to policy limits, must be approved by the RMC and reported to both Boards.
- The policy lists approved geographic regions, products, transaction limits and risk metrics. For trading activities related to optimizing the BC Hydro system, the limits are based on the physical capability to deliver without compromise to domestic reliability. For off-system transactions, limits are based on the volume of open positions and commitment duration. (*From BC Hydro Report on Export Trade, June 2000 Report*).
- Middle Office is subject to a number of internal audit reviews during the year, and the external audit review annually.
- Understanding is that the structure, policy and governance has not changed significantly in the past five years; modeling techniques and analysis are continually evolving.

3. Power Risk Management

Risk Management Policy

- Powerex maintains a Risk Management Policy, which governs Powerex's trading practices and the management of risk. The policy contains specific limits for trading decisions as well as defined approval requirements for authorized exceptions, such as longer-term transactions. The policy and any changes must be approved by both the BC Hydro Board of Directors and the Powerex Board of Directors. In addition, the policy is reviewed by both the BC Hydro and Powerex Risk Management Committees prior to being presented to the Board. Any changes from the conservative risk profile would require approvals by all these levels.
"BC Utilities Commission, Response to Information Request No.2.162.2, issued March 29, 2004."

From BC Hydro's Report on Export Trade, June 2000:

- Energy transactions between BC Hydro and Powerex are solely sales and purchases of energy. Powerex's activities are designed to support optional economic utilization of BC Hydro's electricity assets by using non-committed generation capability to earn income. Powerex works closely with BC Hydro's Power Supply.

- Powerex trades in three main markets: Alberta, U.S., Pacific Northwest and California.

- Power Supply determines the net capability of the BC Hydro system to deliver and/or receive power at the BC border varying from real time to several years ahead. Power Supply establishes the system marginal value of generation.

  a) Real time – hour-to-hour coordinations occurs between the BC Hydro's shift operations engineer and the Powerex Real Time Trader who work in close proximity
  b) Short-term – Power Supply next-day operations planners seek input from Powerex trades on expectation of market prices and quantities
  c) Medium-term – same process for the next day to 3 year period. BC Hydro planners provide Powerex with the generation capability available each month for trade, based on framework of availability, load and outage schedule
  d) Long-term – All energy transactions in excess of three years require approval of the Risk Management Committee and/or the BC Hydro and Powers Board.

- Contracts over 5 years require separate Government approvals.

- The BC Hydro Commodity Risk Management Policy (CRMP) was approved in 1999 by the Board, and has been reviewed and endorsed by government.

- The CRMP describes the risk management policies, controls and processes related to electricity trade transactions. This includes: market and audit exposure limits for transactions, products, counterparties, locations or portfolios, valuation methodologies, transaction controls, and reporting and approval processes by Powerex.

- The CRMP controls the followings risks:
  - Price risk – due to changes in market prices or validity
  - Credit risk – due to counterparty default on delivery and/or settlement
  - Procedural risk – due to procedural errors, or willful breaches
  - Volume risk – due to lower production volumes and transmissions constraints.

- Any changes to the CRMP must be approved by the RMC and the Boards of both BC Hydro and

Powerex.

For short-term obligations (February 2005) from BC Hydro June 2007 presentation

- Policy objective is to reduce risk associated with the cost of energy.

- Criteria for electricity hedging under CRMP:
  - Instruments limited to financial products
  - Product shall be below the domestic buy price
  - Permissible volume range is defined as a percentage of expected imports

- Significant flexibility in electricity hedging to target periods of elevated risks, to adapt to change conditions and take advantage of knowledge of the Pacific Northwest system.
- As hedges continue to expire, hedged percentage will decrease.
- Most transactions will be buy and hold, will tend to avoid transactions that have wider bid-offer spreads.

Commodity Price Risk

- BC Hydro enters into derivative contracts to manage commodity price risk. Risk management strategies, policies and limits are designed to ensure BC Hydro's risks and related exposures are aligned with the Company's business objectives and risk tolerance. Risks are managed within defined limits, regularly reviewed by the Board (*BC Hydro 2009 Annual Report*, pg. 100).

From BC Hydro 2009 Annual Report, pg. 105:

- BC Hydro manages commodity price exposure through an established risk management framework that limits market risk exposures, delegates authority to trade, pre-defines approved products and mandates regular reporting of exposures. A Risk Management Committee forms a key part of the corporate governance framework.

- BC Hydro's trading activities are subject to limits and controls, including:
  - Value at Risk (VaR) in US dollars
  - Stop-Loss/Gain limits
  - Transaction Limits

- These various market risk limits are approved by the Board of Directors.
- Powerex uses an industry standard monte carlo VaR model, a 95% confidence interval, and a 10-day holding period.
- Using this methodology, Powerex's VaR was approximately US $11 million at March 31, 2009
- Powerex uses additional means to supplement the use of VaR to measure price risk including weekly stress tests, notional limits for illiquid or energy products, and independent reporting of non-standard options.

Derivative Financial Instruments and Hedges

- BC Hydro and its subsidiaries use derivative financial instruments to manage interest rate and foreign exchange risks related to debt and exposure to electricity market prices.

- Gains or losses from financial derivatives related to commodity prices are recognized in trade revenues for energy trading activities and certain liability management derivatives that are not accounted for as hedges, mark-to-market accounting is applied. (*BC Hydro 2009 Annual Report*, pg. 85.).

4. Power Sales Management

Long Term Energy Contracts

- Understanding is that the vast majority of power sales are short-term and that long-term contracts are mostly fixed price with an escalator.
- BC Hydro, excluding Powerex, has long-term energy purchase contracts to meet a portion of its expected future domestic electricity requirement. The minimum obligations under these contracts have a total value of approximately $16.9 billion of which $2.4 billion relates to natural gas contracts at market prices over 30 years. The remainder of the commitments are at predetermined prices. Powerex has energy purchase commitments with a minimum payment obligation of $4.9 billion extending to 2025. (*BC Hydro 2009 Annual Report*, pg. 110).

Independent Power Producers

- As of 2009, BC Hydro has 89 Electricity Purchase Agreements with Independent Power Producers (IPPs), representing about 14,400 GWh/year of energy purchases. During fiscal 2009, IPPs provided nearly 8,400 GWh of energy to the system, representing about 14% of total domestic electricity requirements. (*BC Hydro 2009 Annual Report*)

Energy Trading

- Powerex was formed in 1988 to market and track energy to help optimize BC Hydro's electric system resources.
- Total trade revenues were $1.5 billion in fiscal 2009.

	F2005	F2006	F2007	F2008
Electricity Trade Sales Volume (GWh)	29,706	29,906	33,372	37,450
Average Sales Price - Electricity ($/MWh)	$63	$79	$64	$65
Gas Trade Sales Volume (GWh)	2,640	6,641	7,964	14,365
Average Sales Price - Gas ($/MWh)	$59	$76	$62	$58

From: BC Hydro 2008 Annual Report (no table in 2009 report)

- Hydro generation levels in F2009 were 14% lower then the previous year due to lower than average systems inflows into system reservoirs. To meet domestic load requirements, BC Hydro was required to purchase more energy from the market, increasing the overall cost of energy. (*BC Hydro 2009 Annual Report*, pg. 58).

5. Forecasting Models

Modeling Approach

From BC Hydro 2008 LTAP Application, Section 5 and Appendices F14 and F15

- Within BC Hydro's 2008 Integrated Energy Plan/Long-Term Acquisition Plan (LTAP), Section 5 outlines their Risk Framework and Portfolio Analysis.

- Uncertainty was analyzed in three ways for the 2008 LTAP:
  1) Stochastic modeling (using historical data)
  2) Scenario Analysis, and
  3) Qualitative Assessment.

- Key stochastic uncertainties include:
  - load growth and the risk that load growth exceeds or falls below expectations
  - features of the existing system including inflow and water variability and the risk of inefficient energy; and
  - actual gas and electricity spot market uncertainty and price fluctuations.

- Key subjective assessments include: regulatory development, IPP Development, DSM deliverability and transmission supply.

- BC Hydro applies a structured, consistent method to attach a probability estimate to discrete outcomes (e.g., high, mid, low) and combines the results using an 11-branch probability tree (5 branches for the mid outcomes, and 3 each for high and low outcomes).

- Section 4 outlines BC Hydro's Market Assessment. A third party, Global Energy Decisions, Inc., prepared the Natural Gas Price Forecast at Sumas Hub, for BC Hydro, utilizing three internally consistent, fundamentals-based scenarios (base, high, low) of future market conditions. In the 2008 LTAP, BC Hydro discontinued the use of a weighted average of forecasts (previously used internal, US Energy Information Administration and Confer Consulting). Also, for the first time, the electricity price forecasts incorporate GHG offset costs. Natsource, a third party, prepared the Greenhouse Gas Offset Forecast Report.

- Economic indicator forecasts such as GDP and interest rates are based on B.C. Finance forecasts.

Types of Models

- For portfolio analysis, the 2008 LTAP utilized two internally developed models:
  - Multi-Attribute Portfolio Analysis (MAPA), and
  - Hydrological System Stimulation Model (HYSIM).

- In addition to these two models, System Optimizer (SO) was used to select resources in various portfolios. System Optimizer is a product of Ventyx (formerly Global Energy, Henwood). Ventyx also provides the Market Analytics Software issued by BC Hydro to produce its market electricity price forecasts.
- SO is a deterministic tool using linear optimization analysis.
- MAPA/HYSIM runs through 60 years of water records in modeling the large hydro system. (Appendix F15 of the 2008 LTAP contains details of resource planning models).
- The base case assumptions utilized in the portfolio analysis for both cost of capital and discount rate is 6%. Sensitivity analysis examines higher rates.

1. Corporate Overview

Company Address/Key Contacts

75 René-Lévesque Blvd. West
20th floor
Montréal, Québec H2Z 1A4 CANADA
(514) 289-2211
http://www.hydroquebec.com/en/

Financial Snapshot ($CDN)

Latest Fiscal Year:	2008	**Long-Term Debt:**	$36,415 million
Revenue:	$12,717 million	**Equity:**	$22,062 million
Domestic Revenues:	$10,445 million	**Debt to Equity:**	67:33
Export/Trade Revenue:	$1,919 million	**Return on Equity:**	15.4%
Net Income:	$3,141 million	**Total Assets:**	$66,774 million
Fiscal Year End:	December		
Employees (permanent):	19,297		
Employees (temporary):	4,048		

Source:Hydro-Quebec 2009 Annual Report

Generation Capacity

Installed Capacity:	36,429 MW
Generation:	206,603 GWh
Mix:	Hydroelectric: 93.7% - 34,118 MW Nuclear: 1.9% - 675 MW Thermal: 4.5% - 1,634 MW Hydroelectric: 93.7% - 34,118 MW
Sites:	Hydroelectric: 59 Nuclear: 1 Thermal: 27 Wind: 1

Transmission

From Hydro-Quebec Annual Report 2008:

- TransÉnergie – HQ's system comprises 33,058 km of lines and 510 substations, as well as interconnections with the systems in Ontario, New Brunswick and the U.S. Northeast. HQ stringently applies its rates and conditions of service to ensure non-discriminatory access to its system, in compliance with North American regulatory provisions.
- Distribution – The division operates 110,127 km of lines, a nine-location customer relations centre providing telephone and online services, and five distribution control centres, as well as one hydroelectric generating station and 23 thermal generating stations supplying customers on off-grid systems.

Company Overview

From Hydro-Quebec Annual Report 2008:

- HQ – generates, transmits and distributes electricity. Its sole shareholder is the Québec government. It uses mainly renewable generating options, in particular hydropower, and supports the development of wind energy through purchases from independent power producers. It also conducts research in energy-related fields such as energy efficiency. The company has four divisions:

1 Hydro-Québec Production – generates power for the Québec market and sells its surpluses on wholesale markets. It is also active in arbitraging and purchase/ resale transactions.
2 Hydro-Québec TransÉnergie operates the most extensive transmission system in North America for the benefit of customers inside and outside Québec.
3 Hydro-Québec Distribution provides Quebecers with a reliable supply of electricity. To meet needs beyond the annual heritage pool which Hydro-Québec Production is obligated to supply at a fixed price, it mainly uses a tendering process. It also encourages its customers to make efficient use of electricity.
4 Hydro-Québec Équipement and Société d'énergie de la Baie James (SEBJ), a subsidiary of Hydro-Québec, design, build and refurbish generation and transmission facilities, mainly for Hydro-Québec Production and Hydro-Québec TransÉnergie.

Ownership/Subsidiaries

- HQ is a government-owned Crown Corporation
- HQ has one subsidiary - Société d'énergie de la Baie James (SEBJ)

Regulatory and Planning Framework

- Regulated by the Régie de l'énergie

2. Risk Governance

Risk Governance

From Hydro-Quebec Annual Report 2008:

- The Vice President – Accounting and Control is responsible for overseeing accounting (financial, regulatory and management), control and taxation. It also has the task of producing and analyzing the consolidated financial statements. Its other duties include financial planning and risk management.
- Risk governance at HQ starts with policies and monitoring of KPIs (annually). View goes from top down to identify the sources of risk and their associated costs/benefits and probabilities.

- On the energy side, there are two risk policies: one for market risk that outlines key indicators that the board is focused on and which have to be tracked and reported to Market Risk Committee. The RMC is comprised of the president, controller (vice president from accounting), VP in charge of commercial activities for accounting (non-voting) and a senior legal affairs representative for hydro (voting). The trading program is enforced by risk management group which develops policies; board will then authorize trading capacity.
- Credit Risk group has a general policy adopted by the board, reflecting rating agencies and what they track (traders trade within established limits, if they go outside the limits, a notification is issued). When this group started, credit was not as important as market risk, now those roles have been reversed. There is a separate Credit Risk Committee (with the same membership as the MRC less the legal affairs representative) that oversees credit risk for HQ.
- In 2000, HQ obtained a license to market power in the US North-East and moved into integrated power trading. Before 2000, energy was only distributed to the border and sold there. As HQ moved into integrated power and trading and they were taking risks they had never encountered before. This new form of trading introduced risks which had not been taken before, therefore a detached mid-office was created.

Middle Office

- HQ's middle office is primarily an Energy Risk Management group that focuses on the energy-side risk; it houses specialists in credit risk and market risk. It is focused on marketing and hedging activities to help control net income variability.
- 10 people work in the group: 2 credit specialists, 2 IT types and other control and analytic specialists
- The middle office has a role in auditing the financial models used (e.g., cross hedging). The back office audits the middle office.

- The role of the Energy Risk Management office has changed with the growth of HQ and as they continue to grow, they have been absorbing other areas of the business (e.g., equipment risk is now under their umbrella)
- Regarding IT software, HQ's ERM group favours developing in-house systems, allowing it to move as the market changes. HQ will hire specific expertise from outside, when necessary, to assist in model development.

Identified Risks

From Hydro-Quebec Annual Report 2008:

<u>Financial risks</u>

- In the course of its operations, Hydro-Québec carries out transactions that expose it to certain financial risks, such as market, liquidity and credit risk. Rigorous follow-up and the adoption of strategies that include the use of derivative instruments considerably reduce exposure to such risks and their impact on results.

Financial risk: market risk

- Hydro-Québec's results are subject to three types of market risk associated mainly with fluctuations in the Canadian dollar's exchange rate compared to the U.S. dollar as well as fluctuations in interest rates and aluminum prices. Exchange rate fluctuations affect revenue from sales denominated in U.S. dollars as well as the cost of U.S. dollar–denominated debt and swaps. Interest rate fluctuations affect financial expenses, pension costs and the authorized return on equity of regulated divisions. Aluminum price fluctuations have an impact on the net revenue from special contracts with large industrial customers in Québec.
- The three types of market risk are subject to active integrated management, in particular through derivative financial products. The purpose of such management is to limit the impact of market risks on Hydro-Québec's short-term results, according to strategies and criteria established based on the company's risk tolerance. Furthermore, Hydro-Québec can count on certain offsetting factors that mitigate its market risk over the medium and long term. For example, it holds debt and swaps denominated in U.S. dollars as a hedge against sales in that currency. The effect of exchange rate fluctuations on sales is thus partially offset by exchange gains or losses on debt in U.S. dollars. There is also an offsetting effect between the impact of a general increase or decrease in interest rates on financial expenses, on the one hand, and the impact of such an increase or decrease on pension costs and the authorized return on equity of regulated divisions, on the other.

Financial risk: credit risk

- Credit risk is the risk that a counterparty may not meet its contractual obligations. Hydro-Québec is exposed to credit risk related to receivables through ongoing energy sales in Québec. These sales are billed at rates that provide for cost recovery according to conditions approved by the Régie de l'énergie. The company is also exposed to credit risk related to cash equivalents, short-term investments and derivative instruments traded with financial institutions and other issuers and, to a lesser extent, with North American energy companies under Hydro-Québec Distribution supply contracts and Hydro-Québec Production energy transactions in markets outside Québec.
- Exposure to credit risk is mitigated by the implementation of limits and frameworks for risk concentration and level of exposure by counterparty. To ensure compliance with such limits and frameworks, Hydro-Québec takes a proactive approach based on various controls and monitoring reports. These enable it to react quickly to any event that could have an impact on the financial condition of its counterparties. In addition, the company generally does business with counterparties that have a high credit rating. It also enters into agreements to limit the market value of the main portfolios of derivative instruments.

3. Power Risk Management

Risk Management Policy

From Hydro-Quebec Internal Document: *Summary of the Risk Management Programs Related to Wholesale Energy Marketing and Trading Activities at Hydro-Québec Production*

- The VP Wholesale Markets (HQ Production) is responsible for fiscally optimizing Hydro-Québec's generating assets through marketing, hedging and trading. All transactions are required to be made within the guidelines of two risk management programs: one regarding market risk and the other regarding credit risk. These risk managements programs are approved by the Board of Directors and updated at least annually or on an as needed basis.

From Hydro-Quebec Annual Report 2008:

- For several years, Hydro-Québec has applied an integrated enterprise risk management process that is now part of its ongoing business practices. This process is supported by various control, communication and assessment mechanisms that enable Hydro-Québec to monitor risk developments on a dynamic basis.
- Hydro-Québec's divisions and corporate units are central to the process. As part of their ongoing activities, they manage risks and reassess them, daily in some cases. In concrete terms, each division or corporate unit must determine and assess its main risks and then develop and apply mitigation measures to ensure that residual risks are at a level acceptable to Hydro-Québec.
- During the annual planning process, this exercise results in a consolidated portfolio of enterprise risks. This portfolio is presented to the Board of Directors with the Strategic Plan or the annual Business Plan, which includes an analysis of the sensitivity of net income to the principal risks. The divisions and corporate units report on their risk management follow-up and activities to the Management Committee, which then acts as a risk management committee to oversee risk management.

- Energy Risk Management has two main risk policies:
  - Market Risk Policy: The Board sets market-based trading limits. HQ's trading program is established by the MRC. The risk management group, along with the front and back offices, analyzes each trade independently (including simulating the portfolio with VaR). This analysis is brought to the MRC and it validates that the trade fits within the board limits, and then approves the trade.
  - Credit Risk Policy: set limits for each level of agency ratings (A+, etc). It also explains how to authorize new limits.

- Risk Identification – ERM specifies key variables (source of risk): aluminum, interest, exchange rate, water, energy prices and then determines what values these sources of risk can take. They then determine of the company's activities are affected by these sources and make decisions on how to deal with risks and their effect on net income.
- Risk Definitions – one aspect of bringing risks to the board is to provide definitions of those risks and make it standard for the company. HQ maintains one definition matrix for all its different activities.
- ERM packages risk information monthly, focusing on key indicators. Major risks to the company are reported at the board level.
- Enterprise Risk Management separates financial risks (risks you can put a dollar amount on) and other risks (reputation, etc.). The other risks that are difficult to quantify are not taken into account in the probability model. Risks subjectively quantifiable (nuclear, pandemic, reputation) are tracked, but within a different ERM group (at the upper level, enterprise wide).
- Limits in place – VaR, credit limits in terms of exposure, collateral threshold management, volumetric limits (energy per tenor or month). When the HQ system recognizes that it is approaching a risk limit, yellow flags alert other management areas.

- Methods – for longer term trades, HQ favours historical VaR; shorter term it prefers GaR models. HQ possesses tremendous amounts of market data which it uses for stress tests. HQ does not set hard limits on scenario testing; they use their professional judgment and are constrained by volumetric and tenor limits.
- Stress testing is identified as best practice, and allows management to be proactive rather than reactive. HQ ERM policy says they have the obligation to do this stress testing. Used as a management tool, but also allows transparency for auditors

Derivative Financial Instruments and Hedges

- HQ does not trade weather derivatives.
- For hedging, HQ looks as far as 1 to 2 years ahead, but most is done within 3 months, though 2 days is possible. To enforce this with traders, a percentage curve is provided: i.e., 20% for 3 year. Based on ratios (i.e., 20% for certain time period), traders need to stay within protocols; if a trader goes beyond a limit it needs to be properly documented.
- In regards to reporting for Board, President, and VPs, within risk policies and guidelines it will state what kind of documentation and reports need to be produced at each level. Several reports are created and are based on the pyramid structure of HQ leadership.
- Trends over the last 5 years include: more control flags to eliminate manual transfers; and IT has developed procedures to make things more secure.

4. Power Sales Management

Long-Term Energy Contracts

- HQ does not currently have many long-term contracts, but would like to include more in its portfolio in the future.
- HQ does not have any contracts with a tenor greater than 5 years other than legacy contracts from the 1970s and 1980s.
- HQ does not lock in long-term prices because it is difficult to find a counterparty for this type of contract in its export markets.
- HQ uses floating price contracts linked to indices (i.e., MAS hub; Zone A (NY); HOEP (ON))
- Long-term contracts for firm power sales were abandoned in 2000, but now major projects are supporting the case to enter into them again. HQ will export excess power from new major projects. To build assets, HQ needs a specific return (risk is built in) and a minimum Profit/Loss. Before contract is offered, ERM prices everything in the models.
- If there is a solid counterparty, there is less risk. HQ needs to maintain a return of some amount, so may charge a premium to riskier counterparties.
- HQ is willing to leave something on the table to get something else that of economic benefit to HQ or the province.

Energy Trading

- HQ has big reservoirs and demand has grown by 2 or 3% per year, so historically the organization has used the interties as a buffer.
- Approximately 90% of electricity produced is consumed within Quebec.
- A large part of the trading is done through hedging or market trading on a very short term basis.
- The last layer of trading is the sale/resale of physical energy when there is latent capacity with interties.
- HQ benefits from fact that they have green energy.

5. Forecasting Models

Modeling Approach

From Hydro-Quebec Annual Report 2008:

- We operate our facilities in such a way as to maintain a sufficient energy reserve at all times to offset a potential runoff deficit equivalent to 64 TWh over two consecutive years and 98 TWh over four. In compliance with the industry's current reliability criteria, we also keep a capacity reserve approximately 8% higher than our contract commitments.

From Hydro-Quebec Internal Document: Summary of the Risk Management Programs Related to Wholesale Energy Marketing and Trading Activities at Hydro-Québec Production:

- The HQ risk analysis models and software are developed and supported in-house, with external resources called upon (i.e., specialized consultants, research centers, M.Sc. students, etc) when specific expertise is needed.
- HQ risk analysis models and software are developed and supported in-house. When needed, specific expertise if acquired externally (specialized consultants, research centers, M.Sc. students...).
- Inputs for these models are obtained from external and internal sources. For example, spot prices and forward prices come from ISOs and brokers/marketers. Data pertaining to the generating and transmission equipments (e.g., hydraulic forecasts) come from other areas within HQ.

- Many groups do modeling at HQ: hydrological specialists model how much water can vary; others have transmission models and know planned productions, water risks, etc. Some of the data ERM receives comes from models from specialists and all of it will be integrated into ERM's risk model. Other groups rely on outputs from the ERM model (i.e., the equipment group).
- Hydrological specialists decide on probabilities for inputs. They know the marginal impact this factor has on model outputs. They document their assumptions and sources and understand the sensitivities. The hydrological team has 10 staff members.
- All models areas are each very specific in their approach.
- Models are segmented by time frames: short-term models that are real time, monthly models, yearly models and models for 5 years and 10 years into the future.
- Use independent sources on forward curves, but always to be referenced to neutral curve. If they are asked to justify, they can explain strategy with this reference. This allows them to make decisions that are different from the mainstream.
- HQ creates its own forward curves, but buys external forward price. There are lots of different models, but they all come to mutual consensus.
- The main driver of HQ's hydro forecasts is historical data, but HQ employs experts in the field. These experts provide their perspective and will adjust a parameter (with expert justification); this allows forecast to not be totally neutral.
- Serial correlation in the hydro forecast has been measured and examined, but ERM believes that it is not a large factor in its forecasts. ERM believes this is the result of HQ's large reservoir system in comparison to other companies and HQ's ability to better control for it over the long run.
- ERM uses models to determine the effect of new build projects on HQ's revenue.
- HQ does Black Swan stress tests and puts emphasis on longer-term analysis because hedging now looks farther ahead than it used to. HQ looks at the effect of drought over a few years.
- HQ has looked at climate change through external firms; they have sophisticated models to look at very long term effect on HQ to evaluate the impact on future water flows.
- HQ has been assessing the risk in terms of extreme events (low water inflows) for at least the last 20 years. These are based on the historical cycles of inflows and are viewed on both 2 and 4 year inflows. HQ needs to be able to withstand low water for 2 years.

1. Corporate Overview

Company Address/Key Contacts

Ontario Power Generation
700 University Ave
Toronto, ON M5G 1X6
(416) 592-2555
www.opg.com

Financial Snapshot ($CDN)

Latest Fiscal Year:	December 2009	**Long-Term Debt:**	$4.0 billion
Revenue:	$5.6 billion	**Equity:**	$7.5 billion
Domestic Revenues:	n/a	**Debt to Equity:**	
Export/Trade Revenue:	n/a	**Return on Equity:**	
Net Income:	$0.62 billion	**Total Assets:**	$27.6 billion
Fiscal Year End:	December		

Source: OPG Fact Sheet 2009 Year in Review

Generation Capacity

* Based on 2008 generation data

Installed Capacity: 21,748 MW
Generation: 107.8 TWh

Mix: 38% Fossil-fuelled, 32% Hydro, 30% Nuclear, 0.01% Wind
Sites: 3 nuclear generating stations
5 fossil-fuelled generating stations
64 hydroelectric generating stations

- Also co-owns the Portlands Energy Centre and the Brighton Beach gas-fired generating stations

Company Overview

- OPG is an electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG's focus is on the efficient production and sale of electricity from its generation assets, while operating in a safe and environmentally responsible manner.

Ownership/Subsidiaries

From www.opg.com:

- OPG was incorporated on December 1, 1998 under the *Ontario Business Corporations Act.*
- OPG's sole shareholder is the Province of Ontario, as represented by the Minister of Energy.

Core Strategy

- OPG is focused on the following corporate strategies for accomplishing its mandate and objectives
  - Improving its generating asset performance
  - Increasing its generating capacity
  - Achieving financial sustainability
  - Achieving excellence in corporate governance, safety, social responsibility, corporate citizenship and environmental stewardship

Regulatory and Planning Framework

- OPG is regulated by the Ontario Energy Board (OEB). The OEB licenses OPG's generation as well as other activities and will establish the payment amounts for the output of OPG's prescribed generating facilities.

2. Risk Governance

Risk Governance

- Risk management activities are coordinated by a central management group led by a Chief Risk Officer.
- The risk management group is divided into 3 different functions – Corporate Portfolio Risk Management, Enterprise Risk Management and Project Risk Management. Each group has a Director, a Manager and 5-9 analysts/associates. This division acts as the firm's middle office.
- Above the risk management group is the Executive Risk Committee which is comprised of the direct reports to the CEO. The ERC meets quarterly.
- There is also an Energy Markets Risk Oversight Committee that makes decisions regarding energy trading. The committee is comprised of the CFO, CRO, SVP of Corporate Business Energy Markets, VP of Energy Markets and the Controller of Energy Markets. This group meets quarterly, but can review trades for approval between meetings.

Middle Office

- The Corporate Portfolio Risk Management Group, under the CRO acts as the middle office for all trading activity.
- 70-80% of that group's time is dedicated to assisting Energy Market Trading, with the remainder to supporting Treasury and line functions.
- The back office is housed under the controller of energy markets. This group employs 30-40 people.
- The middle office vets and reviews all of the modeling which is done by the Planning Analysis Group within Energy Markets.
- Use ZaiNet (Sun Guard product) as main software for trade capture and middle office monitoring.

3. Power Risk Management

Risk Management Policy

- OPG has a comprehensive and fully-integrated risk management evaluation process that is able to continually evaluate the effectiveness of risk mitigation activities against significant risks faced by the Company. This process is called the Business Unit Risk Self Assessment (BURSA).
- The BURSA process includes the following steps:
  - Each business unit identifies up to 10 risks
  - The risk management group consolidates the list and works with the ERC to prioritize these risks on an enterprise basis
  - The ERC votes to determine the top risks for the organization (typically a total of 10 risks)
  - Risks that do not make the top 10 are included on a "monitored list"
- Each quarter during the ERM reporting cycle, subsequent to the BURSA process, the list of top 10 or so risks is re-evaluated.
  - These 10 risks are monitored by the respective Risk Owners
  - Changes to these risks are provided to the risk management group and significant changes reported to the Board and the Executive Risk Committee quarterly
  - Monitored risks can be moved up to the top 10 risks, top risks can be moved to monitored, and top or monitored risks can be moved off the list all together as circumstances change
- BURSA is a bottom-up process. Recently they have added another process where the risk group goes to the executive team to ensure that they have identified all major risks. This ensures that risks that may be small to the individual business units, but are important to the overall organization are captured in the process.

Market & Credit Risk

- OPG has limits on both market and credit risk. For credit risk, counterparty limits are used. For market risk there are physical limits as well as VaR limits.
- The Board has approved $15M in VaR for trading, but management lowered this threshold to $5M. Once trading activities reach the $3M and $4M thresholds notifications are sent to all traders and designated management team members.
- Limits are viewed holistically, and not on a trader-by-trader basis.
- OPG's trading operations are closely monitored and total exposures are measured and reported to senior management on a daily basis. VaR is used to measure this risk. For 2008, the utilization of VaR fluctuated between $0.9 million to $4.2 million.
- In the risk policy there are 4 levels of exception to specified limits.
  - The first two levels are escalated to the Board and the ERC. These exceptions are for significant issues, including knowingly breaching limits, etc.
  - The 2nd two levels are elevated to the Energy Markets ROC. These exceptions are more minor and include breaches that may be due to timing, accounting, etc.
  - Whenever an exception notification is required, the credit risk department prepares a memo outlining the details of the exception and decides on the categorization. This memo is circulated to relevant groups.

Derivative Financial Instruments and Hedges

From 2008 OPG Annual Report

- OPG hedges their generation output, fuel requirements, NO emission requirements and SO_2 emission requirement. The percentage hedged is outlined below:

	2009	2010	2011
Estimated generation output hedged (1)	89%	83%	83%
Estimated fuel requirements hedged (2)	99%	87%	77%
Estimated NO emission requirement hedged (3)	100%	100%	100%
Estimated SO_2 emission requirement hedged (3)	100%	100%	100%

1 Represents the portion of megawatt hours of expected future generation production, including power purchases, for which the Company has sales commitments and contracts including the obligations under regulated pricing commitments, agreements with the IESO, the OPA auction sales and the revenue limit on OPG's unregulated assets (which ends on April 30, 2009).
2 Represents the approximate portion of megawatt hours of expected production (and fossil year-end inventory target) from all types of facilities (fossil, nuclear and hydroelectric) for which OPG has entered into some form of contractual arrangements or obligations in order to secure either the expected availability and/or price of fuel and/or fuel related services. Excess fuel inventory in a given year is attributed to the next year for the purpose of measuring hedge ratios. Since production from hydroelectric facilities is primarily influenced by expected weather and weather patterns, fuel hedge ratios for hydroelectric facilities are assumed to be 100 percent.
3 Represents the approximate portion of megawatt hours of expected fossil production for which OPG has purchased, been allocated or granted emission allowances and Emission Reduction Credits to meet its obligations under Ontario Environmental Regulation 397/01.

- OPG has Board authority to hedge up to 5 years into the future, however most hedging contracts cover the balance of year.
- OPG hedges its foreign exchange risk with forwards and other derivative contracts for terms generally less than a year.
- OPG hedges interest rate exposure derivatives and swap agreements. As of December 21, 2008 OPG has total interest rate swap contracts outstanding with a notional principal of $272 million. Terms for the existing OPG hedges are up to 12 years into the future.
- At the inception of a hedging relationship, OPG documents the relationship between the hedging instrument and the hedged item, its risk management objective and its strategy for undertaking the hedge. OPG also requires a documented assessment, both at hedge inception and on an ongoing basis, of whether or not the derivatives that are used in hedging transactions are highly effective in offsetting the changes attributable to the hedged risks in the fair values or cash flows of the hedged items.

4. Power Sales Management

Long-Term Energy Contracts

- OPG's trading function has diminished over time as an increasing percentage of their business is covered by generation output that is regulated.
- OPG opened a US subsidiary for trading in 2009. All of the work by the US subsidiary is outsourced to OPG, and the Board is staffed with OPG employees.
- The majority of energy sales are through the IESO-administered spot market in Ontario.
- OPG enters into some 1-5 year contracts for arbitrage. They have both indexed and fixed price contracts.

5. Forecasting Models

Modeling Approach

From: Regulated Hydroelectric Energy Production Forecast – Stakeholder Meeting #1 November 2, 2007 *& Production Forecast & Methodology – Hydroelectric – EB2007-0905 Exhibit E1, Tab 1:*

- Modeling is housed within the Energy Markets – Planning Analysis group. The modelers interact closely with all three generation departments.
- Lowest production for regulated facilities was 14.2 TWh in 1964
- There could be swings of 1.5 TWh or more from one year to the next
- General modeling methodology
  - Step 1 – Forecast Water Levels and Flows
    - Using hydrological models provided by government agencies, water levels and flows are forecast for the local basins associated with the regulated hydro assets (short-term forecast)
    - Historical water levels and flows are used for forecasts beyond 2 years
  - Step 2 – Forecast Energy Using Water Levels/Flows and OPG Energy Models
    - OPG energy forecast models take water flow information and apply unit energy efficiency ratings (kW/cms) and unit availability information (planned outages and estimates of forced outages) to determine forecast energy production
- Niagara River flow
  - Great Lakes water levels and outflows are forecast using the Hydrological Response Model developed by the Great Lakes Environmental Research Laboratory (US)
  - Input parameters to the current model include:
    - "Starting" elevations for Lake Huron, St. Clair, and Erie based on current month end elevation estimates
    - Default median values for hydrological parameters based on historic data, antecedent conditions, and forecast data from Environment Canada and the US National Oceanic and Atmospheric Administration. These parameters include basin precipitation, runoff and lake evaporation, river flows and factors to account for the impact of ice retardation on the flow
  - Model produces monthly average water level and outflow forecasts for Lakes Huron, St Clair and Erie. Lake Erie water level and outflow forecast produced by the model is compared with the six month advance forecast produced by Environment Canada as a consistency check
  - Adjustments are made to the flow into the Grass Island Pool to reflect reductions due to ice or weed retardation
  - Adjustments can be made to the model for such things as: Lake Ontario water levels, Grass Island Pool leakage level and operating patterns, pump generating station operating patterns, New York Power Authority's diversion and discharge capacities, and the Sir Adam Beck 25 cycle system load and frequency changer limits. These adjustments are based on comparisons of model results with actual values, and are used to improve forecast accuracy.
  - Potential transactions with NYPA are also computed in the model, with adjustments based on assessment of historical performance with respect to transactions. However, water transactions with respect to the use of OPG's share of water by NYPA are not included in the production forecast for the regulated hydro facilities
- Sir Adam Beck Stations energy production
  - An OPG model was specifically developed for the Beck Complex and is used to forecast the energy production of the Sir Adam Beck Stations
  - The model takes into account peaking of the SAB PGS, planned outages, differing unit efficiencies, etc.
  - Energy output from the model is adjusted to reflect factors that cannot be specifically

predicted/modeled such as Automatic Generation Control, spill loss de to excess base generation in the IESO system, etc.

- Welland Canal Diversion of Flow from Lake Erie
  - Flow forecast based on historical diversion flows, with consideration given to forecast Lake Erie levels, plant outages, and navigation and other requirements
- DeCew Falls Station energy production
  - An OPG model that has conversion efficiencies calculates energy from water diverted through the Welland Canal and respects various local constraints
  - Forecasts of diversion are prepared based on historical diversion flows, forecast Lake Erie water levels, outages planned for the DeCew plants, scheduled rowing regatta events (OPG reduces generation to provide appropriate conditions for major events) and St Lawrence Seaway Management Corp. navigation needs and plans for canal maintenance.
  - Energy production forecasts are made using a spreadsheet application known as Rivmonth. It uses forecast diversion flow, unit availability information based on planned outages, and generating unit efficiency ratings to calculate the combined monthly energy production for the DeCew Falls stations.
- St Lawrence River flow forecast
  - Lake Ontario Regulation Plan 58D Model (International St Lawrence River Board of Control – the body that regulates Lake Ontario and St Lawrence River outflows and levels) is used to forecast Lake Ontario levels and St Lawrence river flows. Forecast for periods beyond two years trend back towards historic monthly median values
  - Forecasts are compared with values produced by both Environment Canada and NYPA and are then used as input to the Rivmonth energy production model for up to the first six months of the forecast period.
- RH Saunders energy production
  - A general hydroelectric station energy forecast model, developed within OPG, is used to forecast energy production at RH Saunders
  - RH Saunders' generating unit efficiency ratings and outage schedule are also incorporated into the Rivmonth model

Nalcor Energy (Newfoundland and Labrador)

1. Corporate Overview

Company Address/Key Contacts

Nalcor Energy (Newfoundland and Labrador)
Hydro Place
500 Columbus Drive
St. John's, NL, A1B 0C9 Canada
(709) 737.1440
www.nalcorenergy.com

Financial Snapshot ($CDN)

Latest Fiscal Year:	2008	**Long-Term Debt:**	$1,175.7 million
Revenue:	$569.2 million	**Equity:**	$ 934.5 million
Net Income:	$ 82.2 million	**Debt to Equity:**	56/44
Fiscal Year End:	December 31	**Return on Equity:**	10.0%
Employees:	1,237	**Total Assets:**	$2,479.7 million

Source: Nalcor 2008 Annual Report

Generation Capacity

Installed Capacity:	7,307 MW (1,635 NLH; 5,428 Churchill Falls; 241 other projects)
Generation:	34,847 GWh in 2008
Mix:	97% hydro/3% thermal, 80/20 for Newfoundland & Labrador Hydro (NLH)
Sites:	Churchill Falls is one of the largest underground hydroelectric facilities with 11 turbines with a rated capacity of 5,428 MW. NHL has nine hydroelectric plants, one oil-fired plant four gas turbines, 25 diesel plants.

Transmission

- 4,820 km of transmission lines, with over 3,700 km for NLH and over 1,000 km for Churchill Falls

Company Overview

- Guided by the Province of Newfoundland and Labrador's long-term 2007 Energy Plan, the Province established Nalcor, a new provincial energy corporation in 2008.
- Nalcor Energy's foundation is built on its base business: the generation and transmission of electrical power. Over the past three years, the company has expanded into the broader energy sector, including oil and gas, industrial fabrication, wind energy, and research and development.
- Nalcor has five lines of business: Newfoundland and Labrador Hydro, Churchill Falls, Lower Churchill Project, Oil and Gas, and Bull Arm Fabrication.
- Hydro is the primary generator and transmitter of electricity in the province.
- Hydro's operations consist of electricity sales to three primary customer groups – Newfoundland Power that distributes electric power to 236,000 customers on the Island portion of the Province, over 36,000 rural costumers, and major industrial customers.
- The Lower Churchill Project is in the assessment stages and plans to add a combined capacity of over 3,000 MW of hydroelectric power.

Ownership/Subsidiaries

Nalcor Energy (Newfoundland and Labrador)

- Crown Corporation of the Government of Newfoundland and Labrador.
- Newfoundland and Labrador Hydro (NLH) and Nalcor – Oil & Gas are subsidiaries of Nalcor Energy. Churchill Falls is an active subsidiary of NHL and maintains a 33% ownership in Twin Falls Power Corporation.

Core Strategy

- The *Energy Corporation Act* (2008) mandates Nalcor to invest in, engage in, and carry out activities in all areas of the energy sector in the province and elsewhere, including:
  - Developing, generating, producing, transmitting, distributing, delivering, supplying, selling, exporting, purchasing and using of power from wind, water, steam, gas, coal, oil, hydrogen or other products used or useful in the production of power;
  - Exploring for, developing, producing, refining, marketing and transporting hydrocarbons and products from hydrocarbons;
  - Manufacturing, producing, distributing and selling energy related products and services; and,
  - Research and development.

- The *Hydro Corporation Act* (2007) mandates NLH be responsible for: developing and purchasing power and energy on an economic and efficient basis; engaging within the province and elsewhere, in the development, generation, production, transmission, distribution, delivery, supply, sale, purchase and use of power from water, steam, gas, and other products; and supplying power, at rates consistent with sound financial administration, for domestic, commercial, industrial or other uses in the province, and, subject to the prior approval of the Lieutenant-Governor in Council, outside of the province.

Source: from Nalcor Energy 2008 Annual Performance Report (June 2009)

Demand Side Management Programs

- In 2008, NLH and Newfoundland Power (investor-owned utility) filed a five-year joint Energy Conservation Plan with the regulator.
- In 2008, the companies launched takeCHARGE, providing information, tools and programs for energy conservation and efficiency.
- Nalcor's activities resulted in energy reductions of approximately 500 MWh in 2008.

Regulatory and Planning Framework

Regulator: Newfoundland and Labrador Board of Commissions of Public Utilities (PUB)
The PUB is responsible for regulatory oversight, including determination of rates, rate structure, and capital program approvals.

Planning:

- Key planning document is the 20-year Capital Plan. In 2008, Nalcor filed a $1.2 billion, 20-year Capital Plan to the PUB focused on investments to upgrade its aging infrastructure.

Environmental - Emissions

- An ISO Certified Environmental Management System (EMS) governs activities in Nalcor's base hydro business. A focus is the reduction of carbon emissions from thermal generation.
- The proposed Lower Churchill Project will have a combined capacity of 16.7 terawatt hours of electricity per year, and could displace 16 megatonnes of CO2 emissions per year from thermal, coal and fossil fuel generation.

2. Risk Governance

Risk Governance

- The Board consists of 6 independent directors and the CEO, and has four Board Committees.
- The Board's Audit Committee covers risk management policy.
- Noted in the 2008 Performance Report, the goal is to complete a corporate restructuring that facilitates financing requirements and appropriate risk and cost allocation.

From the 2008 Annual Report, Section 3: Managing Risk:

- Risks are identified and assessed based on the probability and severity of a potential occurrence. Events that could have significant impact on corporate strategic goals are identified and mitigation procedures are effected. Through continual updating of risk management practices, Nalcor ensures the protection of physical and financial assets. Nalcor has identified two major categories of risk: operational and financial.
- In terms of operational, the corporate insurance program is reviewed and updated annually. Each operational area and facility within Nalcor's subsidiaries have developed comprehensive response plans to provide guidance and contingency processes in the event of an emergency. Nalcor also has emergency response plans at the corporate level.
- Internal Audit assists Nalcor in achieving objectives with a systemic evaluation of risk management, cost controls and governance processes.
- Understanding is enterprise risk management framework/policy is in early stages and in process for Nalcor, a relatively new corporation.
- At management level, Corporate Treasurer is assigned responsibility for coordinating risk management.

Key Risks

Opportunities and Challenges from 2008 Performance Plan

- Energy costs – challenge affecting the cost of energy supply to consumers in the province.
- Workforce changes – attracting and retaining qualified, skilled staff poses a significant challenge.
- Long-term asset management plan – a significant portion of the NLH's asset base is 30 to 40 years old and well into original life expectancy.
- Implementation of the Energy Plan.

Middle Office

- Currently there is no middle office. There was no energy trading function until the Recall Power Sales Agreement in April 2009. Nalcor has contracted the trading function for the Recall Power Sales to Emera Energy (Nova Scotia Power).

3. Power Risk Management

Risk Management Policy

- Understanding is the risk management policy is in early stages and in process.
- Corporate Treasurer is responsible for credit risk, market risk, currency risk and liquidity risk.
- Annual Report notes Risk Management in terms of managing exposure to credit risk, liquidity risk and market risk in the normal course of Nalcor's business. The majority of receivables are from regulated utilities which minimizes credit risk. Long-term liquidity risk is managed by issuing a portfolio of debentures with maturities ranging from 2014 to 2033 (Annual Report, Financial Statements Note 14).
- Market risk is primarily risk of loss from changes in interest rates, commodity prices and foreign exchange rates.
- Understanding is that Nalcor recently established an internal investment evaluation group (including finance, treasury, tax, technical and legal perspectives) to provide a rigorous due diligence process and sign-off on every major deal, acquisition, investment and contract, before going forward for Board approval.

Commodity Price Risk

- Nalcor's primary exposure to both foreign exchange and commodity price risk arises within Hydro from its purchases of No. 6 fuel for consumption at one of its generating stations. During 2008, Hydro had total purchases of No.6 fuel of $103.9 million (2007 -$122.0 million). These purchases are denominated in US dollars.
- Nalcor's exposure to both the foreign exchange and commodity price risk associated with these purchases is mitigated through the operation of the Rate Stabilization Plan (RSP). The purpose of the RSP is to both reduce volatility in customer rates as well as mitigate potential net income volatility from fuel price and volume variations. All variances in actual fuel prices and exchange rates as compared to that approved in Hydro's most recent COS used to set rates, are captured in the RSP and are either refunded to or collected from customers via automatic rate adjustments. Nalcor also employs the periodic use of forward currency contracts as a means by which exposure to exchange rates on a particular day can be avoided. As at December 31, 2008, there were no forward contracts outstanding.

Source: Nalcor 2008 Annual Report, Financial Statements Note 14

Derivative Financial Instruments and Hedges

- In the 2008 financial statements, there was no reference to derivative financial instruments or hedging.
- Understanding is that historically there has been little volatility. With trading activity starting in 2009, hedging strategy is new to Nalcor and 75% of US currency exposure is hedged out to two years, and 30% of commodity price exposure is hedged for electricity out to one year.

4. Power Sales Management

Long-Term Energy Contracts

- NLH has a number of long-term power purchase agreements, including a continual 175 kW hydroelectric contract, two small (3-4 MW) 25-year hydroelectric contracts, a 20-year, 15 MW co-generation contract, a 15-year 390 MW wind contract and two 20-year, 27 MW wind contracts. These are a relatively small share of NLH's power, most is sold in regulated markets.
- The majority of Churchill Falls' annual electricity production (34,000 GWh in 2008) is sold to Hydro Quebec through a long-term purchase agreement set to expire in 2041.
- Churchill Falls long-term, fixed price contract entered in 1969 provides for almost 90% of the energy from this facility (approximately 30 terawatt hours) until 2041. In addition, under a Guaranteed Winter Availability Contract (GWAC) signed in 1998, Churchill Falls provides additional capacity to Hydro Quebec during the months of November through to March, until the end of the power contract in 2041. In 2008, electric energy sales from Churchill Falls exported to Quebec was 30,007 GWh at a fixed rate of .25 cents per KWh.

Source: 2008 Annual Report

Energy Trading

- Effective April 2009, the Recall Power sales have changed from a fixed price contract to a contract with market-based pricing for electricity.
- On April 2, 2009, the Government of Newfoundland and Labrador announced that for the first time in the province's history, Newfoundland and Labrador is now wheeling hydroelectric power through neighbouring Quebec into the North American marketplace. Nalcor Energy, through its subsidiary, Newfoundland and Labrador Hydro (Hydro) has signed an agreement to wheel power through Quebec to the Canadian – United States border.
- Hydro signed a Transmission Service Agreement with Hydro Quebec (HQ) under HQ's Open Access Transmission Tariff for power transmission from Labrador to the Canada-U.S. border. Hydro is then selling power on the Canadian side of the border to Emera Energy Inc. Emera Energy began selling that power to the energy markets in Canada and the United States on April 1, 2009. This power is from the recall block that Newfoundland and Labrador has access to from the Upper Churchill project.
- NL Hydro has had a power purchase agreement (PPA) with Hydro Quebec for a block of recall power from the Upper Churchill since 1998. The original contract was renewed for a three year term in 2001 and again in 2004 for a five year term. This renewal expired on March 31, 2009. Hydro has the right to recall 300 MW at the same price as HQ's current pricing under the 1969 Churchill Falls power contract. On average, NL Hydro uses approximately 170 MW of power for use in Labrador leaving approximately 130 MW available for export after domestic and industrial requirements in Labrador are met. Under recall sales arrangements, only energy surplus to the province's needs would be exported. NL Hydro expects to be selling up to 250 MW of power which is the maximum available during the summer months.

Source: Government of Newfoundland and Labrador News Release, April 2, 2009

5. Forecasting Models

Modeling Approach

- Internal models use linear and probabilistic analysis including monte carlo simulations.
- Hydrological models based on historical records
- Models have not changed significantly in past five years.

Types of Models

- Mostly in-house models.
- For the Lower Churchill Falls project, also using a PricewaterhouseCoopers model out of London.
- Use TERA for market price forecasting.

Emera Inc. (Nova Scotia Power)

1. Corporate Overview

Company Address/Key Contacts

Emera Inc. (Nova Scotia Power)
1894 Barrington Street
Barrington Tower
Halifax, NS B3J 2A8
(902) 450-0507
www.emera.com

Financial Snapshot ($CDN) – Emera

Latest Fiscal Year:	December 2008	**Long-Term Debt:**	$2,159 million
Revenue:	$1,332 million	**Equity:**	$1,546 million
Domestic Revenues:	N/A	**Debt to Equity:**	58:42
Export/Trade Revenue:	N/A	**Return on Equity:**	9.35% (NSPI)
Net Income:	$145 million	**Total Assets:**	$5,269 million
Employees:	2,215		

Generation Capacity – Emera

Installed Capacity:	3,038 MW
Capacity Mix:	Thermal 63% Hydro 33% IPP 4%
Generation:	15,205 GWh (includes 3,493 GWh of purchases)
Generation Mix:	Thermal 70% Hydro 7% Purchases 23%
Sites:	NSP has a fleet of 5 thermal, 1 tidal and 33 hydro plants, as well as 4 combustion turbine and 2 wind turbine sites (source: www.nspower.ca)

Source: Emera 2008 Annual Financial Report pg. 102

Transmission – Emera

Source: Emera 2008 Annual Financial Report pg. 102

- System of 6,400 km of transmission lines and 32,600 km of distribution lines delivering power to 601,560 customers, 535,494 residential.

Company Overview – Emera

Source: Emera 2008 Annual Financial Report pg. 7

- Canadian energy holding company that invests in electricity generation, transmission and distribution, as well as gas transmission and energy marketing.
- Foundation in regulated businesses
- Regulated utilities generate more than 90% of earnings and assets

Ownership/Subsidiaries – Emera

Source: Emera 2008 Annual Financial Report pg.7 and www.emera.com

- Most of Emera's revenues (approximately 90% of consolidated revenues) are earned by its two wholly-owned regulated electric utilities Nova Scotia Power Inc. (NSPI) and Bangor Hydro-Electric Company (BHE)
- NSPI is the primary electricity supplier in NS, providing over 95% of electricity generation,

transmission and distribution in the province
- BHE is the second largest electric utility in Maine; their core business is the transmission and distribution of electricity

Other Emera investments include:
- Brunswick Pipeline – 100% owned, 145 km pipeline to deliver natural gas from St. John, NB to the US border
- Emera Energy Services – 100% owned physical energy business which purchases and sells natural gas and electricity
- Bayside Power – 100% owned 260 MW gas-fired combined cycled power plant in NB
- Bear Swamp – 50/50 JV in a 600MW pumped storage hydro-electric facility in Massachusetts
- Grand Bahama Power Company Ltd. – 25% indirect interest in a vertically integrated electric utility on Grand Bahama Island
- Lucelec – 19% interest in a vertically integrate electric utility on the island of St. Lucia
- Maritimes & Northeast Pipeline – 12.9% interest in pipeline that transports NS offshore natural gas to markets in Maritime Canada and northeast US
- OpenHydro – 8.2% interest in an Irish renewable energy company (underwater tidal turbines)

Core Strategy

Source: Emera 2008 Annual Financial Report pg. 7

- Generate results for its shareholders and its customers
- Build greater capacity to meet stakeholders' needs and pursue new opportunities to meet tomorrow's energy requirements
- Deliver annual consolidated earnings growth and build and diversify their earnings base
- Seek growth from their existing businesses and leverage its core strength in the electricity business
- Pursuing both acquisitions and greenfield development opportunities in regulated electricity transmission and distribution and low risk generation
- Serve the US market by capitalizing on opportunities in related energy infrastructure businesses appropriate to Emera's risk profile

Demand Side Management (DSM) Programs

Source: NS UARB Evidence of NSPI (dated April 7, 2009)

- Delivery of 2010 DSM programs is expected to cost $22.9 million. Projected incremental demand and energy savings are 16.9 MW and 82.7 GWh, respectively.
- In 2008, DSM programs cost $3.2 million and had incremental demand and energy savings of 2.1 MW and 16.1 GWh, respectively.

Regulatory and Planning Framework

Source: Emera 2008 Annual Financial Report pg.12 & 22

Regulator: Nova Scotia Utility and Review Board (UARB) – NSPI
Maine Public Utilities Commission (MPUC), Federal Energy Regulatory Commission (FERC) – BHE

Planning:
- UARB has supervisory powers over NSPI operations and expenditures
- Electricity rates for NSPI customers are subject to UARB approval

- In November 2008, the UARB approved the implementation of a Fuel Adjustment Mechanism (FAM) effective January 1, 2009

- The rates for each of BHE's distribution services, stranded cost recoveries, and transmission services are established in distinct regulatory proceedings
- Distribution operations and stranded costs are regulated by MPUC, transmission operations by FERC

Environmental

Source: Emera 2008 Annual Financial Report pg. 49-50

- Developed environmental management systems (EMS) to help meet legal requirements and company policy with respect to the environment
- NSPI is to increase the supply of renewable energy by 5% by 2010 and 10% by 2013 (as of Jan 2007)
- Greenhouse gas emissions from NSPI will be capped from 2010-2020

2. Risk Governance

Risk Governance

Source: Emera 2008 Annual Financial Report pg. 46

- Significant risk management activities for Emera are overseen by the Enterprise Risk Management Committee (ERMC) to ensure that risks are appropriately assessed, monitored and controlled within predetermined risk tolerances established through approved policies.
- The company's risk management activities are focused on those areas that most significantly impact profitability and quality of earnings. These risks include, but are not limited to, exposure to commodity prices, foreign exchange, interest rates, credit risk, and regulatory risk.
- Within the last 3 years, NSPI has developed an operational risk group that is not fully autonomous from Emera. This risk management group reports to the ERMC.
- There is some overlap in activities performed by the two groups because the UARB wants to see a risk focus exclusively on NSPI.
- CFO of Emera is also the CRO. The CRO shares several risk responsibilities with the manager of the middle office and the treasurer.
- Produce daily exposure reports and credit availability reports, various monthly reports dealing with portfolio compliance and internal exposure (for front office), more extensive quarterly reporting on exposure, and annual reporting on risk.

Key Risks

Source: Emera 2008 Annual Financial Report pg. 47-50

- The Fuel Adjustment Mechanism (FAM) has been established to mitigate the effects of volatile fuel costs, including related foreign exchange risk, on the electricity rates paid by the customers of Nova Scotia Power.
- Interest rate risk – this is managed through a combination of fixed and floating borrowing and a hedging program.
- Foreign exchange risk – utilize foreign exchange forward and swap contracts to limit exposure on fuel purchases to currency rate fluctuations. In addition, Emera uses foreign exchange forward contracts to hedge the currency risk for capital projects and receivables and revenue streams denominated in foreign currencies.
- Credit risk – contractual obligations between Emera and other counterparties is managed by assessing the counterparties' financial creditworthiness prior to assigning credit limits based on the Board of Directors' approved credit policies.
- Regulatory risk – the regulatory bodies governing NSPI and BHE make it easier for the utilities to recover costs and help ensure that the rates charged to customers reflect the actual price of the fuel used to make electricity.
- Labour risk – contracts with unions at both NSP (expiring in 2012) and BHE (expiring 2010).
- Concentration risk – mitigated by having several counterparties.
- Liquidity risk – the risk that Emera cannot meet its financial obligations.

Middle Office

- Middle office at NSPI is comprised of 5-6 people and is the official keeper of market indices from which counterparty risk and transaction reasonableness is marked.
- Responsible for the daily monitoring and reporting of counterparty exposure limits.
- Review every transaction entered in the trading system for violations of protocol.
- Responsible for allocating credit amongst the various business operations of Emera.
- Compare trades to market comparables to protect against rogue trading.
- Perform stress testing and scenario analysis of the counterparties and credit allocations.
- Middle office is delegated components of the risk management program by the CRO.

3. Power Risk Management

Risk Management Policy

- NSPI has developed internal documentation to identify daily limits for traders, define risks and provide guidance on power transactions and required approvals.
- Have a clear structure to create diversity in their portfolio and help identify contracts that would fit the portfolio.
- In developing the risk management program, NSPI employed experts in the different commodities they deal with to help ensure that all risks were identified.

Commodity Price Risk

Source: Emera 2008 Annual Financial Report pg. 47-48

- Substantially all of Emera's annual fuel requirement is subject to fluctuation in commodity market prices, prior to any commodity risk management activities.
- Emera utilizes a portfolio strategy for fuel procurement with a combination of long, medium, and short-term supply agreements.
- Look for supply and supplier diversification through a strategy designed to reduce the effects from market volatility through agreements with staggered expiration dates, volume options, and varied pricing mechanisms.
- Emera manages exposure to commodity price risk utilizing a portfolio strategy, combining physical fixed-price fuel contracts and financial instruments providing fixed or maximum prices.
- NSPI manages exposure to commodity price risk utilizing financial instruments providing fixed or maximum prices. The approximate percentage of commodity requirements hedged or contracted as at December 31, 2008 are as follows:

	F2009	F2010	F2011	F2012
Coal/Petroleum Coke	91%	29%	19%	7%
Heavy Fuel Oil	100%	58%	n/a	n/a
Natural Gas	99%	67%	n/a	n/a
Purchased Power	97%	100%	60%	10%

- The Company uses value-at-risk limits to manage its exposure to energy commodities from commercial activities on behalf of third parties such as the purchase and sale of natural gas and electricity, and related energy management services.
- These commercial activities are monitored on a daily basis by the Company's risk management group such that the value-at-risk is not material.
- Over the last 6 years, NSPI has been developing a Fuel Manual to help manage commodity and derivative risk associated with the purchase of fuel (largest risk of the utility).
- Manual provides very defined limits on counterparties and other risks faced, in addition to credit limits.

Derivative Financial Instruments and Hedges

Source: Emera 2008 Annual Financial Report pg.47-48

- The company manages its exposure to foreign exchange, interest rate, and commodity risks in accordance with established risk management policies and procedures.
- The company uses financial instruments consisting mainly of foreign exchange forward contracts, interest rate options and swaps, and coal, oil and gas options and swaps.
- Coal/Petroleum Coke – enter into fixed-price and index price contractual arrangements with several suppliers as part of the fuel procurement portfolio strategy. All index priced contractual arrangements

are matched with a corresponding financial instrument to fix the price. Physical contracts are used to hedge coal price risk, due to the lack of liquidity in the financial markets for coal.

- Heavy Fuel Oil – manage exposure to changes in market price through the use of swaps, options, and forward contracts.
- Natural Gas – entered multi-year contracts to purchase approximately 65,600 mmbtu of natural gas per day. Volumes exposed to market prices are managed using financial instruments where the fuel is required for NSPI's generation; and the balance is sold against market prices where available for resale. Fixed price gas volumes not required for generation will be resold into the gas market with the margin hedged using financial instruments.

4. Power Sales Management

Long-Term Energy Contracts

- NSPI is an opportunistic exporter of power, but are very much focused in the spot market – long-term export contracts are not seen as profitable due to the nature of its generation.

Source: Emera 2008 Annual Financial Report pg. 11

- NSPI has one long-term contract that was entered into during Q1 2007. Bear Swamp entered into a long-term agreement with the Long Island Power Authority (LIPA) to provide 345 MW of capacity to May 31, 2010 and 100 MW thereafter to April 30, 2021. In addition, Bear Swamp will provide LIPA with 12,200 MWh of super-peak and peak energy weekly at a fixed price, with an annual increase over the 15 year term of the agreement.

Independent Power Producers

Source: Emera 2008 Annual Financial Report pg. 12, 80 & 100

- During 2008, NSPI signed power purchase agreements for 246 MW of new wind energy sources with seven independent power producers.
- NSPI has an annual requirement to purchase approximately 952 GWh of electricity from independent power producers over varying contract lengths ranging from five to 25 years.
- Bangor Hydro has various contracts committing it to purchase annually, net of resale revenues, approximately $7 million to $11 million of electricity for the period from 2009 to 2019 from independent power producers. These commitments are reduced to less than $2 million each year from 2018 to 2026.
- BHE has several above-market purchase power contracts pre-dating the Maine market restructuring (March 2000). Power purchased under these arrangements is resold to a third party at market rates as determined through a bid process administered and approved by the MPUC. The difference between the cost of the power purchased under these arrangements and the revenue collected from the third party is recovered through stranded cost rates.
- NSPI's existing long-term natural gas purchase agreement includes a price adjustment clause covering three years of natural gas purchases. The clause states that NSPI will pay for all gas purchases at the agreed contract price, but will be entitled to a price rebate on a portion of the volumes, settled in November 2007 and November 2010.

Energy Trading

- NSPI traders have defined limits that are communicated daily.
- NSPI has an established strategy group that makes decisions on transactions greater than a specified value or time period.
- NSPI is a winter peaking utility and typically has power available for export into other markets during the summer.

5. Forecasting Models

Modeling Approach

- UARB requires NSPI to use a 23 year average time frame (for hydro assets) when forecasting for rate cases.
- NSPI uses various time periods for internal forecasting (long-, short-, and near-term). They forecast for average, but understand the ability to supply in a range of outcomes.
- At NSPI, they always plan against the average historical waterflow – its view is that 80% of the outcomes are within 10% of their average.
- One of the biggest risks they model for are emission caps; make an allowance for upset conditions
- Approximately 8 dedicated modelers at NSPI.
- Over the last 5 years, not much has changed in terms of their approach to modeling, but have refined their analysis to include more scenario and probabilistic analyses to come up with a range of potential outcomes.

Types of Models

- Models are purchased externally, but are tailored to the specific requirements of their system.
- Stochastic models used when stress testing counterparties and credit allocations.
- Purchase forward curves and modify depending on the commodity (to adjust for bid-ask spread).
- Have started developing model documentation to guide new hires.

1. Corporate Overview

Company Address/Key Contacts

905 N.E. 11th Ave.
Portland, OR 97208
(503) 230-3000
www.bpa.gov

Financial Snapshot ($USD)

Latest Fiscal Year:	2009	**Long-Term Debt:**	$12.40 billion
Revenue:	$2.87 billion	**Equity:**	$2.56 billion
Domestic Revenues:	$2.87 billion	**Debt to Equity:**	83:17
Export/Trade Revenue:	$0.00 billion	**Return on Equity:**	N/A
Net Income:	($0.10 billion)	**Total Assets:**	$19.64 billion
Fiscal Year End:	September		
Employees:			

BPA's rates are not structured to provide a rate of return on rate base assets, therefore regulatory assets are recovered at cost without an additional rate of return.
Source: 2009 BPA Annual Report

Generation Capacity

Installed Capacity:	13,485 MW
Generation:	8,361,000 MWh
Mix:	89% hydro, 8.5% nuclear, 2.5% firm contracts and other resources
Sites:	31 dams in Idaho, Oregon, Washington and Montana

Company Overview

- The agency markets wholesale electric power from 31 federal hydro projects owned by the US Army Corps of Engineers and Bureau of Reclamation, one non-federal nuclear plant owned and operated by a consortium of utilities, and several other small non-federal power plants.
- BPA also operates and maintains about 3/4 of the region's high-voltage transmission system.
- About 1/3 of the electric power in the Pacific Northwest (PNW) is provided via BPA.
- BPA is a self-funding agency that covers its costs by selling or exchanging wholesale power and related services at cost to meet the needs of consumer-owned utilities and investor-owned utilities in the region.
- BPA also sells or exchanges power with some large industries in the region and with markets and utilities in Canada and the western US.

Ownership/Subsidiaries

- BPA is a federal agency situated under the Department of Energy.

Core Strategy

- The Bonneville Power Administration's mission as a public service organization is to create and deliver the best value for its customers and constituents as it acts in concert with others to assure the Pacific Northwest:
  - An adequate, efficient, economical and reliable power supply;

  - A transmission system that is adequate to the task of integrating and transmitting power from federal and non-federal generating units, providing service to BPA's customers, providing interregional interconnections, and maintaining electrical reliability and stability; and
  - Mitigation of the Federal Columbia River Power System's impacts on fish and wildlife.
- BPA is committed to cost-based rates, and public and regional preference in its marketing of power. BPA will set its rates as low as possible consistent with sound business principles and the full recovery of all of its costs, including timely repayment of the federal investment in the system.
- BPA's policy objectives include the following five objectives:
  - A rate design that meets BPA's financial standards, including meeting the 95 percent two-year TPP;
  - Lowest possible rates, consistent with sound business principles, including statutory obligations;
  - Lower, but adjustable, effective rates rather than higher but stable rates;
  - A risk package that includes only those elements BPA believes can be relied upon; and
  - Reserve levels that are not built up to unnecessarily high levels.

Regulatory and Planning Framework

Regulator: Federal Energy Regulatory Commission

Planning:

- The Pacific Northwest Electric Power Planning and Conservation act of 1980 directs BPA to establish and periodically review and revise rates for the sale and disposition of electric energy and capacity and for the transmission of nonfederal power. Rates are to be set to recover the costs associated with the acquisition, conservation and transmission of electric power, including the amortization of federal investment in the Federal Columbia River Power System.

2. Risk Governance

Risk Governance

From 2009 BPA Annual Report:

- In 2002 BPA established an Internal Management Plan as a roadmap to implement Enterprise Risk Management. This set up the overall risk governance structure of the organization.
- BPA has a Chief Risk Officer who reports to the Deputy Administrator. The CRO runs the Risk Management Department which includes Transacting and Credit Risk Management (middle office), Enterprise Risk Management and Business Continuity
- The Enterprise Risk Management Committee (ERMC) aggregates the various key risks faced by the BPA, and understands their overall impact on the organization
- The Transaction Risk Management Committee (TRMC) focuses specifically on transaction-level risks
- The Transactional Risk Policy defines the control environment through which these risks are managed.

From BPA Manual, Chapter 2 – Functional Statement for Office of the Deputy Administrator:

- Enterprise Risk Management (ERM) is responsible for establishing and maintaining BPA's ERM framework, program, and infrastructure to effectively manage its full range of risks on an integrated and agency-wide basis. The ERM program is based on a rigorous and systematic process to identify, analyze, evaluate, and treat risks. This process includes the analysis and measurement of agency financial risk, including the development and maintenance of probabilistic agency financial risk models and metrics, and the development of common procedures for collecting financial risk data from subject-matter experts throughout BPA. The Risk Management group coordinates the activities of the Enterprise Risk Management Committee (ERMC), including definition of agency risk tolerance and the identification, assessment, and treatment of significant risks to agency strategic business objectives.
- Transacting and Credit Risk Management (TCRM) is responsible for measuring, monitoring, controlling, and reporting market risks associated with BPA's commodity transacting activities. It fulfills its risk management and control function in the following ways:
  - Proactively developing commodity transacting risk management policies, procedures and financial risk limits and ensuring that these policies, procedures and limits are updated to reflect leading industry risk management principles and practices;
  - Ensuring that commodity transacting activities are consistent with approved financial risk limits;
  - Institutionalizing key risk measures such as Revenue-at-Risk, scenario analysis, and stress testing to identify potential financial risks under normal and extreme market conditions; and
  - Performing rigorous analysis to quantify market, credit and operational risk exposures to ensure effective senior management and TRMC review of commercial activity. In addition, the TCRM is responsible for administering BPA's insurance programs, providing risk analysis and recommendations for various types and amounts of insurance coverage for the agency.
- Business Continuity Program (BCP) coordinates the development and maintenance of agency wide plans that prepare the agency to continue its essential functions in the event of a major disruption in normal operations. The BCP is responsible for defining standards, tools, and processes to be used in developing the continuity program which are consistent with federal directives and guidelines. Program scope includes Crisis and Incident Management, Emergency Response, Continuity of Operations and Infrastructure Restoration. The BCP supports BPA's service lines and other groups in designing, implementing and maintaining strategies to ensure the availability of essential agency functions, and the necessary business processes, resources, infrastructure and information technology assets, in accordance with management-approved objectives.

From 2010 BPA Rate Case Wholesale Power Rate Final Proposal – Loads and Resources Study July 2009 WP-10-FS-BPA-04:

- Financial reserves are BPA's primary tool for managing the financial risk PS faces. Given the large magnitude of the financial risk, if BPA were to rely solely on augmenting insufficient financial reserves with Planned Net Revenues for Risk (PNRR) for risk mitigation, power rates would need to include a large risk premium to meet BPA's TPP standard.

Middle Office

- There are approximately ten personnel in the middle office – four in the quantitative group, 3.5 in the credit group and 3 in the control group.
- The middle office is responsible for ensuring that regular trading activity falls within the parameters of the Transacting Risk Policy. If a limit is breached, the middle office has the authority to stop the trade. Any trades in a 'gray area' or that are outside of defined policies are directed to the CRO.
- The middle office reviews changes that are made to forecasting models as well as new forecasting models that support trading floor activity. These models are then reviewed by the Risk Committee. Internal Audit is responsible for auditing forecast models.
- Internal Audit conducts regular audits on the roles and responsibilities embedded in the risk policy.
- OpenLink software is used as a real-time database for the front, middle and back offices. Each office has additional software as well.

3. Power Risk Management

Risk Management Policy

From BPA 2009 Annual Report:

- Experienced business and risk analysts and managers conduct simulation and analysis of the hydro supply system and forward market prices to derive market price and credit risk positions. These results are measured against risk limits and reported to senior management daily.
- Credit risk is mitigated by reviewing counterparties for creditworthiness, establishing credit limits and monitoring credit exposure on a daily basis. BPA also obtains credit support, such as letters of credit, parental guarantees, prepayments and deposits or escrow from some counterparties. Counterparties are monitored closely for changes in financial condition and credit reviews are updated regularly.

- BPA has numerous financial and credit limits in place. These are updated on a daily and weekly basis.
- Credit limits include: dollar, tenor, volume and counterparty dollar limits. Each counterparty has individual limits – these may be adjusted as conditions change.
- Risk analytic methods include scenario analysis, stress testing and mark-to-market (for 1 and 30 day periods)
- Risk reports are created for the TRMC and other Senior Managers. Reports include information on credit exposure, trading positions, exposure vs. limits, etc.

Commodity Price Risk

From BPA 2009 Annual Report:

- BPA measures the market price risk in its portfolio on a daily, weekly and monthly basis employing both parametric calculations and non-parametric Monte Carlo simulations to derive net revenues at risk, mark-to-market, VaR, and additional risk metrics as appropriate. The use of these methods requires a number of key assumptions including hydro/price correlations, the selection of a confidence level for expected losses, the holding period for liquidation and the treatment of risks outside standard measures such as sensitivity and scenario testing to determine the impacts of sudden changes in market price, volatility, correlations or hydro inventory.
- Futures, forwards, forwards, swaps and option instruments may be used to mitigate BPA's exposure to price fluctuations.

Derivative Financial Instruments and Hedges

From BPA 2009 Annual Report:

- Effective for fiscal year 2009, BPA adopted new accounting standards for derivatives and hedging, which requires enhanced disclosures on derivative instruments and hedging activities.
- BPA has models which account for winter hedging purchases. In those months and water years when firm loads exceed resources, these winter hedging purchases reduce the amount of balancing power purchases. Conversely, in those months and water years when resources are sufficient to serve firm loads, these winter hedging purchases increase the amount of surplus energy sales.
- BPA does not purchase weather derivatives.

4. Power Sales Management

Long-Term Energy Contracts

Source: 2009 BPA Annual Report:

- In December 2008, BPA signed long-term wholesale power contracts with all 135 preference customers and with most of its investor-owned utility customers. The contracts had been under discussion since 2002.
- Power sales under these contracts will begin in 2012, when most current contracts expire, and will run through FY2028.
- New contracts are paired with a new tiered rate structure, which will send price signals to encourage investments in future electricity infrastructure in the Pacific Northwest.
- Under tiered rates, preference customers will pay Tier 1 rates for power produced by the existing federal system, with limited augmentation.
- As load grows beyond what the system can produce, customers have a choice to secure non-federal power on their own or purchase additional power through BPA at Tier 2 rates.
- Tier 2 rates would be set to cover the full cost of the additional power BPA would buy to meet additional loads
- Rates include a Cost Recovery Adjustment Clause which allows BPA a temporary upward adjustment of power rates up to $36 million
- Long-term contracts represent approximately 80% of BPA's energy sales

5. Forecasting Models

Modeling Approach

From 2010 BPA Rate Case Wholesale Power Rate Final Proposal – Loads and Resources Study July 2009 WP-10-FS-BPA-01:

- In the BPA's WP-93 rate proceeding, it adopted and implemented its 10-Year Financial Plan, which included a policy requiring that BPA set rates to achieve a high probability of meeting its payment obligations to the U.S. Treasury (Treasury). The specific standard set in the 10-Year Financial Plan was a 95 percent probability of making both of the annual Treasury payments in the two-year rate period on time and in full. This TPP standard was established as a rate period standard; that is, it focuses upon the probability that BPA can successfully make all of its payments to Treasury over the entire rate period, rather than setting numerical goals for year-to-year performance.
- PNW regional hydro resource energy generation estimates are used in the forecast of electricity market prices in a Market Price Forecast Study. The regional hydro data includes all PNW regional utility hydro plus NUG hydro for FY 2010-2011. The regional regulated and independent hydro generation is estimated for each of 70 water years of record (October 1929 through September 1998). The regional NUG hydro generation forecast is assumed not to vary by water year because these small run-of-river projects are located on minor rivers or streams that have little or no storage. Therefore, generation levels at NUG hydro projects typically do not have wide variations in generation due to water year variability. The forecast of PNW regional hydro generation is presented for monthly energy in aMW for each of the 70 water years.
- Monthly firm requirement forecasts are prepared for energy in aMW, HLH MWh, LLH MWh, and MW for the Full Service, Partial Service, Slice, and Block customer groups
- Each hydro regulation study specifies particular hydroelectric project operations for fish, such as seasonal flow objectives, minimum flow levels for fish, spill for juvenile fish passage, reservoir target elevations and drawdown limitations, and turbine operation efficiency requirements.
- The HYDSIM model uses streamflows from historical years as the basis for estimating power production of the hydroelectric system.
- There are two modes of operation for the HYDSIM hydro regulation studies: refill and continuous. Both modes estimate the energy production of the hydro system; however, each mode treats a project's initial reservoir conditions differently. Continuous hydro regulation studies operate from one water year to another, using the previous water year's final reservoir elevations as the initial reservoir elevations for the next water year. Refill hydro regulation studies operate each water year independent of all other water years, using the reservoir's initial storage elevation for each water year. Continuous studies are typically used in BPA mid- to long-range planning to provide expected generation estimates for future years. Refill studies are generally incorporated in short-term planning when information on initial reservoir elevations is known.
- BPA determines the amount of its annual forecast firm energy resources under 1937 critical water conditions.
- Variations in monthly loads, resources, natural gas prices, and PS transmission and ancillary service expenses are simulated in risk simulation models (RiskSim). Monthly spot market electricity prices, based on varying loads, resources, and natural gas prices, are estimated by AURORAxmp®. To estimate net revenues, RevSim uses risk data from RiskSim, spot market electricity prices from AURORAxmp®, load and resource data from the Loads and Resources Study, various revenues from the revenue forecast component of the WPRDS; and rates and expenses from the RAM2010.
- The initial water year (FY 2010) of the sequential set of two water years is randomly sampled from 1929 through 1998 using a uniform distribution. When the end of the 70 water years is reached (at the end of water year 1998), monthly hydro production data for water year 1929 is subsequently used.

- The California hydro generation risk factor reflects the uncertainty that the timing and volume of streamflows have on monthly hydro production in a given year in California. Higher California hydro generation generally reduces the need to run thermal plants in California, which results in lower prices paid by California utilities for PNW surplus energy and lower prices paid by PNW utilities for purchased power from California. Lower California hydro generation has the opposite affect.

Types of Models

- Two statistical models are used in the risk analysis step of a rate proposal, the Risk Analysis Model (RiskMod) and the Non-Operating Risk Model (NORM). A third model, the ToolKit, is used to test the effectiveness of risk mitigation tools in the risk mitigation step. AURORAxmp® is the computer model used to develop the market price forecast. Most of the risk simulation models developed to quantify operating risks were developed in Microsoft Excel workbooks using the add-in risk simulation computer package @RISK and Microsoft's Visual Basic for Applications.
- BPA's approach to modeling risks uses Monte Carlo simulation methodology. In this technique, the models RiskMod, NORM, and ToolKit run through 3,500 scenarios, or games. In each game, each of the financial uncertainties is randomly assigned a value based on input specifications for that uncertainty. After all of the games are run, the output data of the set of games are either analyzed and summarized, or passed to other tools for further analysis in the ratesetting process.
- Econometric modeling techniques capture the dependency of values through time. Parameters for the probability distributions are developed from historical data.

1. Corporate Overview

Company Address/Key Contacts

Tennessee Valley Authority
400 West Summit Hill Drive
Knoxville, TN, U.S.A.
(865) 632-2101
www.tva.com

Financial Snapshot ($US)

Latest Fiscal Year:	2009	**Long-Term Debt:**	$21,788 million
Revenue:	$11,255 million US	**Equity:**	$4,218 million
Net Income:	$726 million	**Debt to Equity:**	84/16
Fiscal Year End:	September 30	**Return on Equity:**	18.6%
Employees:	12,219	**Total Assets:**	$40,017 million

Source: TVA 2009 Annual Report

Generation Capacity

Installed Capacity:	33,716 MW (summer net capability)
Generation:	144,772 GWh
Generation Mix:	Coal 53%/Nuclear 37%/Hydro 8%/Other 2%
Sites:	11 coal –fired plants with 59 generating units (14,711 MW) 3 nuclear plants (6,624 MW) 6 hydroelectric facilities with 113 units (5,494 MW) 11 natural gas & oil-fired plants with 93 units (6,871 MW)

Source: TVA 2009 Annual Report

Transmission

- TVA has one of the largest transmission systems in North America. Assets include 15,954 circuit miles of transmission line, 487 transmission substations, power switchyards and switching stations, and 66 individual interconnection points and 1,020 customer connection points.
- TVA has operated with 99.999 percent reliability over the last ten years.

Company Overview

- TVA is engaged in generation and transmission activities, and is a wholesaler of power. TVA generates power from diverse sources including coal, nuclear, hydro and natural gas. It sells power to a network of distributors that resell power to their customers at a retail rate.
- TVA operates the nation's largest public power system and supplies power in most of Tennessee, northern Alabama, northeastern Mississippi, and southwestern Kentucky and in portions of northern Georgia, western North Carolina, and southwestern Virginia, to a population of nearly nine million people. TVA also manages the Tennessee River system to produce power, minimize flood risk, maintain navigation, protect water quality and provide recreational opportunities.
- In 2009, the revenues generated from TVA's electricity sales were $11.1 billion and accounted for virtually all of TVA's revenues.
- Its service area is defined by two federal statutes: *The Tennessee Valley Authority Act of 1933* and the *Federal Power Act.*

Ownership/Subsidiaries

- In 1933, the U.S. Congress created Tennessee Valley Authority, a government corporation, a public power company.
- TVA is owned by the United States Government and is not authorized to issue equity securities.
- Since 1999, TVA has funded all its operations almost entirely from electricity sales and power system financings (primarily the sale of debt securities).

Core Strategy

- TVA's mission is to improve the quality of life in the Tennessee River Valley region through its work in three key areas: energy, the environment and economic development. TVA provides reliable, competitive power, manages the Tennessee River system and associated lands to meet multiple needs, and partners with Valley communities and states for economic development. (Source: *TVA Strategic Plan*).

Key Strengths

- Diversified customer base
- Fuel and geographic diversity
- Good market position, leading producer in the region

Demand Side Management Programs

- In 2009, TVA announced additional energy efficiency programs to promote energy efficiency to residential and commercial customers. The TVA Board directive is to reduce energy use during times of high demand and high cost.

Key Performance Indicators

- TVA has nine key performance indicators: delivered cost of power, fuel cost adjustment costs, productivity, connection point interruptions, customer satisfaction survey, economic development (jobs, investment), equivalent availability, environmental impact index, and workplace safety.
- In addition to corporate level indicators, there are several indicators measured from the COO and Strategic Business Unit report cards.

Regulatory and Planning Framework

Regulator:

- Under the FPA, TVA is not a "public utility", a term which generally includes investor-owned utilities. However, as an "electric utility" and a "transmission utility", TVA is subject to certain aspects of the Federal Energy Regulatory Commission's (FERC) jurisdiction.
- TVA is subject to regulation by the Environmental Protection Agency (EPA) for air and water quality controls and other environmental matters.
- TVA is self-regulated with respect to rates, and the *TVA Act* gives the TVA Board sole responsibility for establishing the rates TVA charges for power. These rates are not subject to judicial review or to review or approval by any state or federal regulatory body.

Under the *TVA Act*, TVA is required to charge rates for power which will produce gross revenues sufficient to provide funds for:

- Operation, maintenance, and administration of its power system;
- Payments to states and counties in lieu of taxes ("tax equivalents");
- Debt service on outstanding indebtedness;
- Payments to the U.S. Treasury in repayment of and as a return on the government's appropriation investment in TVA's power facilities (the "Power Facility Appropriation Investment"); and
- Such additional margin as the TVA Board may consider desirable for investment in power system

assets, retirement of outstanding bonds, notes, or other evidences of indebtedness ("Bonds") in advance of maturity, additional reduction of the Power Facility Appropriation Investment, and other purposes connected with TVA's power business.

In setting TVA's rates, the TVA Board is charged by the TVA Act to have due regard for the primary objectives of the TVA Act, including the objective that power shall be sold at rates as low as are feasible.

Source: TVA 2009 Annual Report, page 10

Planning:

- In 2009, TVA began the preparation of a new Integrated Resource Plan (IRP) entitled TVA's Environmental and Energy Future. The purpose of the IRP is to analyze alternative ways of addressing the Tennessee Valley's electricity needs for the next 20 years. The IRP builds on the energy resource portfolio that resulted from TVA's 1995 IRP. The alternative portfolios developed for this effort will be evaluated using several criteria including capital and fuel costs, reliability, possible environmental impacts including climate change, compliance with existing and anticipated future regulations, and other factors. TVA expects to issue a final IRP in early 2011.

Environmental - Emissions

- TVA's 2008 Environmental Policy aims towards obtaining 50% of its power supply from clean (zero or low carbon emission) sources by 2020. In 2009, about 45% of TVA's total generation came from non-CO2 emitting sources as defined by TVA (hydro, nuclear, renewable wind and solar energy).
- TVA produces about 100 million tons of CO2 emissions per year. In 1995, TVA was the first utility to participate in the Department of Environment's voluntary greenhouse gas emissions program, and over the past decade, TVA has reduced, avoided or sequestered over 305 million tons of CO2. (*TVA 2009 Annual Report*, pg 28).

2. Risk Governance

Risk Governance

- TVA is governed by a nine member Board appointed by the President of the United States with the advice and content of the U.S. Senate.
- In 2007, the Board approved the Strategic Plan. A significant priority of the plan is for the TVA system to have the right balance of generating capacity and energy supply to meet the growth in consumer demand and reduce exposure to the price volatility of the energy markets. Specific actions to carry out the plan are reflected in TVA's annual business and performance plans and budgets.

From TVA 2009 Annual Report, pg. 76:

- The Enterprise Risk Council (ERC) was created in 2005 to strengthen and formalize TVA's enterprise-wide risk management efforts. The ERC is responsible for the highest level of risk oversight at TVA and is also responsible for communicating enterprise-wide risks with policy implications to the TVA Board or a designated TVA Board committee. The ERC's current members are the CEO (chair), the chief financial officer and chief risk officer, the chief operating officer, the General Counsel, and a designated representative from the Office of the Inspector General as an advisory member.
- The ERC has established a subordinate Risk Management Steering Committee (RMSC). The RMSC is responsible for: (1) reviewing risk management policies to ensure their consistency with TVA's Enterprise Risk Management policies and guidelines, (2) reviewing Strategic Business Unit risks and emerging issues, (3) providing executive guidance and support in enterprise risk assessments and risk management plans, (4) recommending enterprise risks for approval to the ERC, (5) recommending general risk management processes and methodologies for the enterprise, and (6) sponsoring special projects related to cross-functional risk management activities.
- TVA has a designated ERM organization within its Financial Services organization, responsible for: (1) coordinating risk assessment efforts at TVA organizations, (2) facilitating enterprise risk discussions with the risk subject matter experts, at the RMSC, ERC, and TVA Board levels, and (3) developing and improving risk governance structure and risk assessment processes and methodologies.

Key Risks

- "The amount of electricity that TVA is able to generate from its hydroelectric plants depends on a number of factors outside TVA's control, including the amount of precipitation, runoff, initial water levels, and the need for water for competing water management objectives. The amount of electricity generation is also dependent upon the availability of its hydroelectric generation plants, which is in TVA's control. When these factors are unfavorable, TVA must increase its reliance on more expensive generation plants and purchased power." (*TVA 2009 Annual Report*, page 14)
- TVA's 10-K Form outlines several Risk Factors (pg. 34-41). These include: regulatory risks, market demand risk, weather risk, operational risks, market and credit risks, financial risks and other factors.

Middle Office

- CFO Office has an enterprise risk area that the Middle Office reports to. Within the financial services area, the Chief Risk Officer is in the chain of command.
- Middle office has less than 10 employees in the commodity risk area; there are also enterprise risk personnel that deal with broader financial risks.
- The commodity risk group provides oversight, accountability and reports any violations. They provide daily positions and daily reports to the front office traders. Understanding is weekly reports go to the CFO and monthly reports go to the members of the Enterprise Risk Council.
- Commodity and risk management IT system is Commodity XL from Triple Point Technology.
- Middle office has some accountability for price forecasting models.
- Subject to internal reviews, federal regulator review as well as external reviews.

- Scope of the middle office has not changed significantly in the past five years, but continues to evolve and is largely focused on commodity issues.

3. Power Risk Management

Risk Management Policy

- As outlined in Risk Governance, TVA has a corporate Enterprise Risk Council and Enterprise Risk Management policies and guidelines. The Risk Management Steering Committee reports to the ERC and reviews risk management policies, provides guidance and support in enterprise risk assessments and risk management plans, and recommends risk management processes and methodologies. There is also a designated enterprise risk management organization within Financial Services.
- TVA has catalogued major short-term and long-term enterprise level risks across the organization.
- Understanding is that TVA does enterprise risk mapping that will affect hedging strategies and trading. Hedging activities and strategies are documented and communicated up the organization. Limits are continually being re-evaluated to ensure they are appropriate for activities.

Commodity Price Risk

- TVA is exposed to effects of market fluctuations in the price of commodities that are critical to its operations, including coal, uranium, natural gas, fuel oil, crude oil, construction materials, emission allowances, and electricity. TVA's commodity price risk is substantially mitigated by its cost-based rates, including its automatic FCA mechanism.
- To manage cost volatility for its wholesale and direct-served customers, TVA has established a Financial Trading Program (FTP). Under the FTP, TVA currently hedges the risks associated with the price of natural gas, fuel oil, and crude oil. TVA is prohibited from taking speculative positions.
- TVA previously used value at risk (VaR) as a measure of commodity price risk. While the VaR approach is a reasonable approach for measuring the risks of portfolios that are primarily speculative in nature, it is less informative when used to measure the risks of hedging programs. Because of TVA policy of not entering into speculative commodity positions and that TVA's exposure to commodity prices is substantially mitigated by its cost-based rates, TVA is discontinuing the use of VaR in favor of a sensitivity analysis of its commodity positions in its Financial Trading Program. (*TVA 2009 Annual Report*, pg. 76).
- In 2007, the TVA Board expanded the FTP: (1) to permit financial trading for the purpose of hedging or otherwise limiting the economic risks associated with the price of electricity, coal, emission allowances, nuclear fuel, and other commodities included in TVA's FCA calculation, as well as the price of natural gas and fuel oil, (2) to authorize the use of futures, swaps, options, and combinations of these instruments as long as these instruments are standard in the industry, (3) to authorize the use of the Intercontinental Exchange as well as the NYMEX to trade financial instruments, and (4) to increase the aggregate transaction limit to $130 million (based on one-day value at risk). In 2009, the TVA Board further expanded the FTP to permit financial trading for the purpose of hedging or otherwise limiting the economic risks associated with the price of construction materials. The maximum hedge volume for these transactions is 75 percent of the underlying net notional volume of the material that TVA anticipates using in approved TVA projects, and the market value of all outstanding hedging transactions involving construction materials is limited to $100 million at the execution of any new transaction. The TVA Board also expanded the FTP to permit financial trading to manage financial risks that occur when TVA contracts for goods priced in or indexed to foreign currencies. The portfolio value at risk limit for these transactions is $5 million and is separate and distinct from the $130 million transaction limit discussed above. (*TVA 2009 Annual Report*, pg. 111).

Derivative Financial Instruments and Hedges

- To help manage certain of these risks, TVA has entered into various derivative transactions, principally commodity option contracts, forward contracts, swaps, swaptions, futures, and options on futures. Other than certain derivatives instruments in investment funds, it is TVA's policy to enter into these derivative transactions solely for hedging purposes and not for speculative purposes. (*TVA 2009 Annual Report, pg 107).*
- There are hedging strategies for each type of commodity used to generate power that gets vetted through the agency, typically will hedge 3-4 years out.
- TVA does not purchase weather insurance/derivatives.

4. Power Sales Management

Long Term Energy Contracts

- Virtually all of TVA's power sales are long-term contracts, based on cost of service.

- Revenues from distributor customers accounted for 86% of TVA's operating revenues in 2009. At September 30, 2009, TVA had wholesale power contracts with 158 municipalities and cooperatives. Each contract requires distributor customers to purchase all of their electric power and energy requirements from TVA.

- All distributor customers purchase power under one of three basic termination notice arrangements:
  - contracts that require 5 years' notice to terminate;
  - contracts that require 10 years' notice to terminate; and
  - contracts that require 15 years' notice to terminate.

TVA Distributor Customer Contracts
As of September 30, 2009

Contract Arrangements*	Number of Distributor Customers	Sales to Distributor Customers in 2009 (in millions)	Percentage of Total Operating Revenues in 2009
15-year termination notice	5	105	0.9
10-year termination notice	48	3,174	28.2
5-year termination notice	103	6,310	56.1
termination notice given**	2	55	0.5
Total	158	9,644	85.7

Notes:
*Ordinarily the distributor customer and TVA have the same termination notice period; however, in contracts with six of the distributor customers with five-year termination notices, TVA has a 10-year termination notice (which becomes a five-year termination notice if TVA loses its discretionary wholesale rate-setting authority). Also, under TVA's contract with Bristol Virginia Utilities, a five-year termination notice may not be given until January 2018.
**One contract is due to terminate in December 2009, and the second is due to terminate in January 2010.

Source: TVA 2009 Annual Report, page 9

- The power contracts between distributor companies provide wholesale rates set by the TVA Board.

Beginning in 2007, rates were automatically adjusted quarterly pursuant to a formula reflecting the changing costs of fuel, purchased power and emissions allowances, called the "fuel cost adjustment". Starting October 2009, rates will adjusted monthly rather than quarterly.

- "The TVA Board regulates distributor customers primarily through the provisions of TVA's wholesale power contracts. All of the power contracts between TVA and the distributor customers require that power purchased from TVA be sold and distributed to the ultimate consumer without discrimination among consumers of the same class, and prohibit direct or indirect discriminatory rates, rebates, or other special concessions. In addition, there are a number of wholesale power contract provisions through which TVA seeks to ensure that the electric system revenues of the distributor customers are used only for electric system purposes. Furthermore, almost all of these contracts specify the specific resale rates and charges at which the distributor customers must resell TVA power to their customers. These rates are revised from time to time, subject to TVA approval, to reflect changes in costs, including changes in the wholesale cost of power. The regulatory provisions in TVA's wholesale power contracts help carry out the TVA Act's objective of providing for an adequate supply of power at the lowest feasible rates." (*TVA Annual Report Form 10-K*, page 10).
- Revenues from industrial customers directly served accounted for 12 percent of TVA's total operating revenues in 2009. In 2009, contracts for customers directly served were generally for terms ranging from five to 10 years. These contracts are subject to termination by TVA or the customer upon a minimum notice period that varies according to the customer's contract demand and the period of time service has been provided.
- Approval process for contracts based on size thresholds. The middle office checks terms and price on commodity contracts.

Independent Power Producers

- Under federal law, TVA is required to purchase energy from qualifying facilities, cogenerators, and small power producers at TVA's avoided cost of self-generating or purchasing this energy from another source. At September 30, 2009, there were seven suppliers, with a combined capacity of 914 MW, whose power is purchased by TVA under this law.

Energy Trading

- To supplement its power generation, TVA acquires power from a variety of power producers through long-term and short-term power purchase agreements as well as through power spot market purchases. During 2009, TVA acquired 27 percent of the power that it purchased on the power spot market, 4 percent through short-term power purchase agreements, and 69 percent through long-term power purchase agreements that expire more than one year after September 30, 2009.

	F2005	F2006	F2007	F2008	F2009
Purchased power (GWh)	14,892	20,887	22,141	19,019	14,892
Percent of TVA's Total Power Supply	13.1%	11.6%	12.4%	10.9%	8.5%

Source: TVA 2009 Annual Report Form 10-K, page 17

5. Forecasting Models

Modeling Approach

- TVA has extensive modeling for hydro and has over 100 years of water flow data. Note hydro constitutes a relatively small (8%) but material part of TVA's total energy sales.
- Previous few years were the worst drought period in 100 years.

From TVA 2009 Annual Report (page 15) on the hydrological model:

- A preliminary analysis that was part of TVA's update to its hydrology model indicated that dam overtopping would occur at four TVA dams under the model's assumptions that define "probable maximum flood" levels. While the "probable maximum flood" is an extremely unlikely event, TVA is taking actions with the aim of ensuring that overtopping would not occur even under these conditions. TVA plans to implement interim dam modifications by January 1, 2010. Permanent dam modifications are being planned to prevent the "probable maximum flood" from overtopping these dams, and cost estimates, which could reach several tens of millions of dollars per dam, are being prepared.
- As a result of the update, TVA is performing additional hydrologic assessments at most of its other dams to determine how many of these dams may also be susceptible to unacceptable overtopping during the "probable maximum flood." The total financial impact of permanent modifications to any additional dams which may be identified as a result of the ongoing assessment will be determined as these assessments are completed in 2010.

Types of Models

- Models are based on a combination of internal and external models customized to TVA. Models have been well developed over time and hydro models are well integrated into the total portfolio.
- Approximately 5-10 personnel are dedicated to hydrological modeling.
- Model mechanics have not changed, continuing to get better from documenting the various interfaces.

1. Corporate Overview

Note: This case study was undertaken to review the hydrological forecasting techniques of the Bureau of Reclamation. The Bureau of Reclamation is responsible for generating hydropower, but does not sell or market to third parties. Therefore, this case study is focused exclusively on its models.

Company/Address/Key Contacts

Denver Federal Centre
6th & Kipling, Building 67
Denver, CO 80225
(304) 445-3514
http://www.usbr.gov/

Financial Snapshot ($CDN)

Latest Fiscal Year:	
Revenue:	n/a
Net Income:	n/a
Employees:	5,642

Generation Capacity

Installed Capacity:	14,859 MW
Generation:	Approximately 40,000 GWh
Mix:	100% Hydro – produce 17% of the hydropower in the US
Sites:	58 hydroelectric power plants

Company Overview

Source: U.S. Department of the Interior – Bureau of Reclamation 2008 Annual Report pg. 2

- The Bureau of Reclamation ("Reclamation") is the largest wholesale water supplier in the United States and the second largest producer of hydroelectric power.
- Responsible for delivering water and generating power in the 17 western states.
- The mission of Reclamation is to manage, develop and protect water and related resources in an environmentally and economically sound manner in the interest of the American public.

Ownership/Subsidiaries

- Branch of the United States Department of the Interior.

Core Strategy

Source: U.S. Department of the Interior – Bureau of Reclamation 2008 Annual Report pg. 4

Some of Reclamation's priorities are:
- Ensure the continued delivery of water and power benefits in conformity with contracts, statutes, and agreements.
- Operate and maintain projects in a safe and reliable manner, protect the health and safety of the public and Reclamation employees, and improve financial accountability and transparency to contractors.
- Plan for the future with programs that focus Reclamation's financial and technical resources on areas in the West where conflict over water currently exists or is likely to occur in coming years.

Key Strengths

United States Bureau of Reclamation (Hoover Dam)

Source: U.S. Department of the Interior – Bureau of Reclamation 2008 Annual Report pg. 25, 61

- Reclamation is a leader in the hydropower industry with respect to low costs and high reliability.
- Forced outage time was at 1.13% compared to the industry average of 1.9%.

Demand Side Management

Source: U.S. Department of the Interior – Bureau of Reclamation 2008 Annual Report pg. 52

- The goal of the Energy Independence and Security Act 2007 is to reduce energy use by 3% a year from 2008 through 2015.
- Reclamation is looking for ways to reduce energy use through water conservation and will use more cost-effective renewable energy technologies including: solar, wind, geothermal and biomass systems.

Key Performance Indicators

Source: U.S. Department of the Interior – Bureau of Reclamation 2008 Annual Report pg. 5

- Reclamation identified 41 action items for 2008 in their *Managing for Excellence* Action Plan that focused on several facets of their organization, practices and culture.
- In FY2008, Reclamation completed the 41 action items (see 2008 Annual Report for more details).

2. Forecasting Models

Modeling Approach

Source: Reclamation presentation on Colorado River Basin and Operational Models

- Look at 4 different time horizons with respect to their operational activities:

Long-term planning
- Have a historical flow record of observed flows dating back to the early 1900s.
- Within the last 3 or 4 years, have started looking at paleo records through tree ring analysis (performed at University of Arizona) to reconstruct flows on the basin dating back to 700 AD. There are droughts that occurred during this period much greater than any observed droughts.
- Huge uncertainties in projecting future water supply and demand; they use the Colorado River Simulation System (CRSS) model for long-term projections.
- Look basin-wide on a monthly time step and use model to compare various operational policies while looking into the future.
- They try to quantify some of the uncertainty in future water flows by running multiple simulations (over 100) to get a probabilistic sense of water flow.
- Most inputs are held constant across scenario runs to help isolate differences across scenario outputs.
- Provides a range of future system conditions to aid comparative analysis of policies.
- Have started looking at climate outcomes/scenarios – precipitation and temperature are run through the hydrological models to try and predict run-off.

Mid-term operations
- These models help determine how they will operate their facilities on a month-to-month basis given the policies that have been put in place.
- Simulate the operation of the 12 reservoirs in the Colorado River basin (including energy generation) for 24 months into the future.
- A set of operational guidelines are provided for the reservoirs; this model projects monthly levels of the reservoirs based on the level in January
- The operational tier for the year (as outlined in the operational guidelines) is determined based on the projections.
- These models are updated every month to reflect changes in hydrology and water demand.
- Monthly forecast data for these models comes from NOAA National Weather Service.

Short-term scheduling
- Schedule releases from dams – trying to meet water delivery targets within constraints (lake elevation targets, energy targets)
- Updated daily to reflect changes in demand and energy targets (or other constraints), look out approximately one month.
- Requires a lot of coordination between offices and agencies.
- Used to set Hoover Dam energy generation target for the month.

Real-time control
- These models are used for automatic generation and control at the facilities.
- The time horizon on these models is about 1 to 7 days.

- Long-term planning group has a team of 3 modelers; the mid-term operations and short-term scheduling group has about 5 or 6 people.
- Modelers have an engineering background with a focus on hydrology.
- There is no user manual for the models, but they do have documented procedures – a new hire would

shadow an incumbent modeler to gain a better understanding of the models.
- Over the last 5 years, they have shifted away from relying on history for future water flows.

Types of Models

- All models are developed using the modeling software RiverWare.
- Use stochastic re-sampling technique to produce future water flow outputs and then perform statistical analyses on outputs.

1. Corporate Overview

Company Address/Key Contacts

LCRA Headquarters
3700 Lake Austin Blvd.
Austin, Texas 78703
(512) 473-3200
www.lcra.org

Financial Snapshot ($USD)

Latest Fiscal Year:	June 2009	**Long-Term Debt:**	$2.93 billion
Revenue:	$1.31 billion	**Equity:**	$0.87 billion
Net Income:	$0.59 billion	**Total Assets:**	$4.22 billion
Fiscal Year End:	June		

Generation Capacity

Installed Capacity: 3,400 MW

Mix: 50% coal, 46% natural gas, 2% hydroelectric, 2% wind

Sites: LCRA generates electricity at a coal-fired power plant (Fayette Power Project in Fayette County), two natural gas-fired plants (Thomas C. Ferguson at Marble Falls, Sim Gideon at Bastrop), and one combined-cycle gas-fired plant (Lost Pines 1 Power Project at Bastrop). LCRA also generates hydroelectric power at its Highland Lakes dams — Buchanan, Inks, Wirtz, Starcke, Mansfield and Tom Miller — and purchases wind power from three West Texas wind projects.

- Hydroelectric generation used to be the major source of LCRA's electric generation capacity. Now they provide power at times of peak demand as water levels allow.
- Hydroelectric generation is now primarily a byproduct of other river operations activities.

Transmission

- LCRA operates more than 3,300 miles of transmission lines throughout the State of Texas.

Company Overview

- LCRA plays a variety of roles in Central Texas: delivering electricity, managing the water supply and environment of the lower Colorado River basin, developing water and wastewater utilities, providing public recreation areas, and supporting community and economic development.

Ownership/Subsidiaries

- LCRA is a conservation and reclamation district created by the Texas Legislature in 1934. It has no taxing authority and operates solely on utility revenues and fees generated from supplying energy, water and community services.
- LCRA has four operating units — Wholesale Power Services, Transmission Services, Water Services and Community Services. In addition, a Corporate Services unit provides shared and corporate services.
- LCRA has two major separate affiliates: GenTex Power Corporation (GenTex), a nonprofit electric generation affiliate that owns Lost Pines 1; and LCRA Transmission Services Corporation, a nonprofit, taxable transmission affiliate that seeks to provide transmission services throughout Texas.

Core Strategy

- The mission of the Lower Colorado River Authority (LCRA) is to provide reliable, low-cost utility and public services in partnership with our customers and communities and to use our leadership and environmental authority to ensure the protection and constructive use of the area's natural resources.

Regulatory and Planning Framework

- Rates for electricity, water and water utilities are set by LCRA's Board of Directors. The Public Utility Commission of Texas approves transmission rates.

2. Risk Governance

Risk Governance
▪ LCRA is governed by a 15 member Board of Directors that is appointed by the Governor of Texas. The Board sets policies to establish the strategic vision of the organization. ▪ Risk management is covered by the Finance and Administration committee on the Board. ▪ There is a Financial Oversight Group (FOG) that reports to the General Manager. The FOG acts as the risk management oversight committee. This group is chaired by the CFO and is staffed with finance staff members. ▪ There is a Risk Control Officer that reports to the CFO. This individual acts as the organization's middle office.

3. Power Risk Management

Risk Management Policy
▪ LCRA's two largest risks are natural gas prices, and counterparty exposure. ▪ Overall program limits are in place, and are updated based on natural gas prices. ▪ There are credit thresholds for margin calls. ▪ They do not purchase weather insurance. ▪ Risk reports are created daily by the back office to recap trading activity. ▪ The Risk Control Officer creates weekly reports on positions, mark to market and standby capacity. ▪ A strategy document is prepared monthly for discussion with the FOG – this document outlines strategic objectives and documents activities related to those objectives.

Derivative Financial Instruments and Hedges
From 2009 Annual Report: ▪ In FY 2009 spot prices for natural gas ranged from $2 to more than $13 per mmBtu. In an effort to mitigate the financial and market risk associated with these price fluctuations, LCRA enters into futures contracts, swaps and options for energy price risk management purposes. ▪ Natural gas prices are hedged mostly for one year into the future, but can be hedged up to four years.

4. Power Sales Management

Long-Term Energy Contracts

From FY2010 LCRA Business Plan:

- As of April 1, 2009, 31 of LCRA's 43 wholesale electric customers had committed to continuing their wholesale power relationships with LCRA until 2041. These customers represent about 62% of LCRA's total energy sales. LCRA continues discussions with the remaining customers and expects that some of them will choose to continue their relationship beyond the 2016 expiration of their current agreements.
- Any excess energy, after contracted load capacity is met, is sold on the spot market. If additional load is required it is purchased in the spot market.
- Electric rates are designed to recover the costs of providing wholesale electric power. LCRA does this through two rate components, a fuel and nonfuel rate, that recover LCRA's costs as listed below:
  - Fuel rate covers costs of fuels used to generate electricity, managing and transporting these fuels to power plants and storage facilities, purchased power, labor for fuel-related activity and risk management. LCRA adjusts this rate periodically to reflect changing costs. This portion varies as input prices change.
  - Non-fuel rate covers labour for non-fuel related activity, operations and maintenance, debt service, hydroelectric operations, expenses from corporate services, contributions to public service fund and other costs. This portion is fixed over the life of the contract.
  - These two rates are combined into a time-of-use pricing structure. Each customer pays the exact same rate for energy based on when it is used. This structure provides LCRA customers with pricing predictability. Any over-payment/under-payment is trued up periodically.
- There is a "closed loop" budgeting process where generation customers receive contractual assurance that revenues collected through electric generation rates, with the exception of contributions to the Public Service Fund, are used for the benefit of the generation system. This also applies to hydroelectric activity.
- All contracts are entered into for 30 years, with the same contractual end date. Each contract is negotiated with "most favoured nations" status, so each customer can choose whether they want the same contract terms that other parties are able to negotiate.

5. Forecasting Models

Modeling Approach

From FY2010 LCRA Business Plan:

- Wholesale Power Services' generation resource plan strategy incorporates the most current view of the wholesale customers' load obligations and key uncertainties such as fuel and market prices, potential environmental regulations, transmission congestion costs, electric market design, new generation opportunities, and generation technology costs. The action plan includes incremental steps to mitigate risk while adding the advantages of fuel diversity and flexibility over the longer term.
- The Drought of Record refers to the decade-long drought that affected Central Texas from the late 1940s through the late 1950s. No other drought in history was as severe or as long. LCRA's Water Management Plan uses this drought as the basis for setting lake storage amounts that serve as "trigger points" for the drought management plan. When the amount of water stored in lakes Buchanan and Travis falls to a combined total of 1.1 million acre-feet, LCRA begins curtailing interruptible water customers. Typically, the levels of the lakes at that storage amount would be about 1,001 feet above mean sea level for Lake Buchanan and about 645 feet above mean sea level for Lake Travis.
- Currently hydrological modeling is done as part of their water services forecasting. LCRA does not forecast their future hydrological load capacity; they only model to optimize the prices of available hydroelectric power.
- For hydrological purposes they take the average capacity over the past twenty years and use this in their models. They do not look back to the Drought of Record as there were no constraints on water supply then, so it is no longer a relevant input.

Types of Models

- Purchase "off the shelf" energy forecasting models, and tailor them to their needs. Most of their models are probabilistic or stochastic.

1. Corporate Overview

Company Address/Key Contacts

123 Main St
White Plains, NY 10601
(941) 681-6200
www.nypa.gov

Financial Snapshot ($USD)

Latest Fiscal Year:	December 2008	**Long-Term Debt:**	$1,744 million
Revenue:	$3,185 million	**Equity:**	$2,567 million
Domestic Revenues:	n/a	**Debt to Equity:**	40:60
Export/Trade Revenue:	n/a	**Total Assets:**	$7,007 million
Net Income:	$299 million		
Fiscal Year End:	December		

Generation Capacity

Installed Capacity:	6,846 MW
Generation:	
Mix:	74% Hydro, 26% Oil/Gas
Sites:	14 oil- and gas-fired generating stations 8 hydroelectric generating stations

Transmission

- 1,400 circuit-miles of high voltage transmission lines

Company Overview

- Largest state-owned, non-profit power organization in the U.S.
- Generation and transmission of electricity
- Sells power to business and industrial customers, government agencies and public systems, investor-owned utilities and healthcare, cultural and educational institutions

Ownership/Subsidiaries

- Owned by the State of New York, but is not supported by any tax revenue or state credit

Core Strategy

- Mission is "to provide clean, economical and reliable energy consistent with our commitment to safety, while promoting energy efficiency and innovation for the benefit of our customers and all New Yorkers."
- To provide low-cost power electricity to New York State
- Provide economical electricity to help promote economic development in the State

Energy Efficiency Services

- NYPA has undertaken more than 1,500 energy efficiency programs at 2,300 public buildings across the State
- These measures reduced demand by more than 190,000 KW – equivalent to the output of a medium sized power plant

2. Risk Governance

Risk Governance

From NYPA Enterprise Risk Management Program May 19, 2009:

- NYPA has a Vice-President and Chief Risk Officer - Energy Risk Assessment and Controls that reports directly to the CFO.
- The CRO is responsible for establishing policies and procedures for identifying, reporting and controlling energy-price and fuel-price-related risk exposure connected with energy and fuel related hedging transactions.
- This role has assumed greater importance since the NYPA began participating in the NYISO energy markets.

- There is an Enterprise Risk Management Committee (ERC) chaired by the CRO which manages the Enterprise Risk Management Policy and direct its implementation. The ERMC's members include:
  - EVP and Chief Engineer – Power Supply
  - SVP Marketing and Economic Development
  - SVP Energy Resource Management
  - SVP Corporate Planning and Finance
  - SVP Enterprise Shared Services
  - VP and Controller
  - Director Insurance Risk
- The ERMC reports to the Executive Leadership Team (ELT) which provides overall risk policy direction and oversight. The ELT will report periodically to Board's Audit Committee on NYPA's critical risks.
- There is also an Energy Risk Management Committee (ERMC)
- Within each department at NYPA there are Risk Owners (RO) who will assess risks, develop and implement risk management plans and Risk Identifiers (RI) who identify and define risks within a department.
- An Enterprise Risk Management group was established in the past year to focus on the organizations most critical risks as established by Senior Management.

Key Risks

- Energy price risk

Middle Office

- Energy Risk Assessment and Controls (ERAC) group, NYPA's middle office has 8 staff members divided into an Energy Risk Reporting group and an Enterprise Risk Planning group. All four people making up the Energy Risk Reporting Group are considered members of the middle office overseeing energy trading activities, while the remaining four staff oversee enterprise risk activities.
- Enterprise Risk Planning acts as the facilitator of the ERM policy, providing consultative advice and assistance on matters relating to risk and the tools and techniques supporting risk identification, assessment, measurement and reporting. They report up through the ERC.
- Energy Risk Reporting performs risk analysis to calculate risk exposure on transactions and the overall portfolio, Monitors counterparty credit, establish credit limits and collateral requirements.
- Report up through the ERMC
- The Controller's Office and the Office of Internal Audit each conduct independent reviews to ensure activities are carrier out under the Risk Management Policy.
- The back office reports up through accounting, and ultimately to the CFO.

3. Power Risk Management

Risk Management Policy

From the Governing Policies for Energy Risk Management January 31, 2006:

- "The objective of the [ERM program] is to identify exposures to movements in energy prices; to understand the impact on the company's financial statements, and its economic well-being and to mitigate the impact of those exposures where they might exceed NYPA's appetite for risk, while maintaining adequate flexibility to improve financial performance."

- Monthly ERM meetings are held to keep everyone informed of market updates, customer requests, and proposed request responses.
- Risk definitions are included in documented policies and procedures
- Most limits are credit-based. There are transaction limits for traders, managed by the counterparty limits. Traders have access to the RM IT system to help them monitor their exposure vs. limits.
- Earnings-at-Risk is a very important metric to the organization
- Perform stress testing – look at the 1% probability outcome
- Over the past 5 years, monitoring energy hedge counterparty credit has become a more important function of the middle office.

Derivative Financial Instruments and Hedges

From the Governing Policies for Energy Risk Management January 31, 2006:

Risk management transactions may include the following:

- Hedging the cost of energy and energy products to be procured for normal business purposes
- Hedging the price of energy and energy products sold by NYPA
- Hedging the margin between energy procured and energy produced where NYPA owns conversion capacity (e.g., "spark spread")
- Hedging the geographic cost differential for energy procured in order to reduce price uncertainty at the location of desired use
- Dynamic hedging will be permitted for the purpose of limiting the divergence of fixed position values from market opportunities, or to secure credits embedded in previous hedge transactions. (subject to constraints set by CEO)
- Contracts to provide energy, capacity or ancillary services

From the Minutes of the Regular Meeting of the Power Authority of the State of New York – June 30,2009:

Authorization Limits[1] for Energy- and Energy Hedging-Related Transactions[2]

(financial and physical settlement, spot and term tenure, excluding transactions with the NYISO)

	Physical	Financial		Transaction Notional Value [3,4,5]			Term[6, 4]
Title[7]	--	OTC	NYMEX[8]	Fuel[9, 10] ($MM)	Electricity[11] ($MM)	Emissions[12] ($MM)	(months)
President and Chief Executive Officer	✓	✓	✓	30	30	10	48
Chief Operating Officer	✓	✓	✓	30	30	10	48
Executive Vice President and Chief Financial Officer	✓	✓	✓	30	30	10	48
Executive Vice President – Energy Marketing and Corporate Affairs	✓	✓		30	30	10	48
Senior Vice President and Chief Engineer – Power Generation	✓			25		4	36
Senior Vice President – Energy Resource Management and Strategic Planning	✓	✓	✓	20	20	2	36
Senior Vice President – Marketing and Economic Development	✓	✓			25	1	36
Director – Power Resource Planning and Acquisition	✓	✓			15	1	24
Others - trading authorization limits delegated by respective department executive[13]							

- 99% of hedging is done on behalf of two customer groups to find the risk tolerance that both the customers and the utility are comfortable with for the upcoming year.

4. Power Sales Management

Long-Term Energy Contracts

- Majority of wholesale transactions are hydro-based. Typically have between 2-2.5 TWh to sell into the competitive wholesale NY market.
- Always sell wholesale power in the spot market.
- All of its customer contracts are long-term – from 10-25 years.
- Preference customer contracts – municipalities, out-of-state hydro customers, residential customers – are priced at the cost of service.
- Other customer contracts are priced with an index. Indices include Producer Price Indices for commodities, electric power and commodities less fuel and the Energy Information Administration Industrial Electric Power Index.
- Many of its contracts are legislatively required. Marketing department handles contract negotiations.
- Contracts need to be approved by the Board. Only financial hedges need to be approved by the middle office, unless of a long-term nature where Board of Trustees approval is needed.

Independent Power Producers

- Have a 5 year PPA for 2TWh for NYC customers.

5. Forecasting Models

Modeling Approach (Hydrological Models)

- NYPA produces a forecast of monthly Niagara and St Lawrence River flows and net generation.
- The GLERL (Great Lakes Environmental Research Lab) developed the AHPS (Advanced Hydrological Prediction System) to model flow of water in the Great Lakes watershed. AHPS consists of a Net Basin Supply (NBS) forecasting model and a lake levels routing model.
- The NBS is overlake precipitation + runoff – lake evaporation
- NBS uses actual meteorological data to determine the current basin moisture and lake heat storage conditions. This determines the current state of the Great Lakes Watershed.
- Historical weather data (1948-98) are used to predict overlake precipitation, runoff and lake evaporation in coming months.

1. Corporate Overview

Company Address/Key Contacts

Puget Sound Energy
10885 NE 4th Street
P.O. Box 97034
Bellevue WA 98009-9734
www.pse.com
www.pugetenergy.com

Financial Snapshot ($USD)

Latest Fiscal Year:	2008
Revenue:	$3.35 billion
Export/Trade Revenue:	$0.84 billion
Net Income:	$0.15 billion
Fiscal Year End:	December
Employees:	2,800

Source: 2008 Annual Report

Generation Capacity

Installed Capacity:	2,926 MW
Generation:	23.6 million MWh
Mix:	13% wind, 8% hydroelectric, 56% natural gas, 23% coal
Sites:	2 wind facilities 3 hydro facilities 8 natural gas facilities 1 coal facility

Source: www.pse.com

Transmission

- 2,639 miles of transmission lines (over 55kV)
- 20,186 mils of distribution lines (under 55kV)

Company Overview

- PSE is an energy company providing electrical power and natural gas in the Puget Sound region of the Northwest United States.
- It serves electrical power to more than 1 million customers in 9 counties
- It provides natural gas to more than 720,000 customers in 6 counties.

Ownership/Subsidiaries

- Puget Sound Energy is owned by a holding company, Puget Energy Inc.
- Puget Energy Inc, was publicly traded, but was purchased by a consortium of private investors in 2009

Core Strategy

- Puget Energy's focus is to concentrate on its core business: retail utility service within a regulated environment. The company's strategy emphasizes meeting the energy needs of the growing PSE customer base through incremental, cost-effective energy conservation, low-cost procurement of traditional energy resources, and far-sighted investment in energy-delivery infrastructure.
- As Washington State's oldest local energy utility, with a 6,000-square-mile service area stretching across 11 Washington counties, primarily in the Puget Sound region, PSE serves more than 1 million electric customers and nearly 750,000 natural gas customers.

Demand Side Management

Program Type	2009 Goal	2009 Actual	Percent of Goal Reached	Actual Achievement
Electric Energy Efficiency Programs	296,353,000 kWh	272,320,002 kWh	91%	Enough electricity savings to power about 23,300 homes.
Natural Gas Efficiency Programs	3,128,600 therms	4,627,320 therms	148%	Enough natural gas savings to heat about 5,500 homes.
Green Power Program	295,647,000 kWh	275,749,000 kWh	93%	This is a CO2 off-set equivalent to taking about 32,600 cars off the road.

Regulatory and Planning Framework

- PSE is regulated by the Washington Utilities and Transportation Commission

2. Risk Governance

Risk Governance

- The Board oversees the risk management policies of the organization. These policies are outlined in the Energy Risk Policy Document.
- Puget has an Executive Risk Committee (ERC) which is made up of:
  - 3 Executive Vice-Presidents
  - Chief Resources Officer
  - CFO
  - COO
  - Head of Systems Operations
- The ERC establishes the risk policies and processes. These are documented in a Hedging and Operational Procedures Manual.
- Under the ERC are three groups – the Risk Management Group, the Portfolio Group and the Risk Control Group.
- The Risk Management group manages the input parameters to the models and control risk management systems. It is staffed with 8-9 employees.
- The Portfolio group maintains the trading portfolio against pre-defined limits.
- The Risk Control group acts as the middle office. It runs risk control systems and assesses the risk of daily operations. It is staffed with 8 employees.
- Software used for trading is OATI and GMS

3. Power Risk Management

Risk Management Policy

- When Puget was bought by private investors in 2009 they conducted an Organizational Risk Assessment. Each of the 5 departments were asked to inventory their risks, assess the exposure of unmitigated risks, document what mitigation strategies are assigned to each and rate each of the risks.
- The long list of risks was prioritized into the 15 largest risks for the organization. This list is updated on a quarterly basis.
- On a daily basis traders get limit reports. If a limit is exceeded a Limit Violation Report is created – then the Trader and the Head Trader need to explain how they will mitigate these risks. The report goes to the ERC.
- Understanding is that they do not use VaR to measure limits. As PSE is a net short utility they do not view VaR as a relevant measure.

Derivative Financial Instruments and Hedges

From 2008 Annual Report:

- PSE is focused on commodity price exposure and risks associated with volumetric variability in the gas and electric portfolios and the related effects noted above. It is not engaged in the business of assuming risk for the purpose of speculative trading. PSE hedges open gas and electric positions to reduce both the portfolio risk and the volatility risk in prices. The exposure position is determined by using a probabilistic risk system that models 250 simulations of how PSE's gas and power portfolios will perform under various weather, hydro and unit performance conditions. The objectives of the hedging strategy are to:
  - ensure physical energy supplies are available to reliably and cost-effectively serve retail load;
  - manage the energy portfolio prudently to serve retail load at overall least cost and limit undesired impacts on PSE's customers and shareholders;
  - reduce power costs by extracting the value of PSE's assets; and
  - meet the credit, liquidity, financing, tax and accounting requirements of PSE.

- Where deemed appropriate, PSE may request collateral or other security from its counterparties to mitigate the potential credit default losses. Criterion employed in this decision includes, among other things, the perceived creditworthiness of the counterparty and the expected credit exposure.
- It is possible that volatility in energy commodity prices could cause PSE to have material credit risk exposures with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, PSE could suffer a material financial loss. However, as of December 31, 2008, approximately 99.9% of the counterparties with transaction amounts outstanding in PSE's energy portfolio are rated at least investment grade by the major rating agencies and 0.1% are either rated below investment grade or are not rated by rating agencies. PSE assesses credit risk internally for counterparties that are not rated.
- PSE has entered into commodity master arrangements with its counterparties to mitigate credit exposure to those counterparties. PSE generally enters into the following master arrangements: (1) Western Systems Power Pool agreements (WSPP) - standardized power sales contract in the electric industry; (2) International Swaps and Derivatives Association agreements (ISDA) - standardized financial gas and electric contracts; and (3) North American Energy Standards Board agreements (NAESB) - standardized physical gas contracts. PSE believes that entering into such agreements reduces the risk of default by allowing a counterparty the ability to make only one net payment.
- PSE purchased weather derivatives, specifically heating degree day options in 2002 and then stopped after one year because of the negative accounting treatment of these instruments.
- Understanding is that PSE's hedging program is based on dollar-cost averaging with hedging instruments purchased monthly, regardless of their price. Hedges go out four year – 100% of exposure

is hedged in the first year, approx. 50% in the second year and diminished amounts in year 3 and 4.

4. Power Sales Management

Long-Term Energy Contracts

- Puget is a net short load serving utility so they do not sell energy through long-term contracts.
- The majority of energy sales are through the IESO-administered spot market.
- Power purchase agreements are typically three month contracts, although 5% of their contracts are greater than 5 years.
- Almost all contracts are based on current market prices, but there is some indexing through the winter.
- Prices are calculated based on avoided cost calculations.
- All contracts longer than three years need to go through the Resource Acquisition Group. These purchase agreements are originated through an RFP process and then are compared to the overall impact on the portfolio.

5. Forecasting Models

Modeling Approach

- Modellers for operational models sit in the risk management group; modelers for long-term Integrated Resource Plan models sit within the Resource Planning group. There are eight modelers in each department.
- As Puget's system is predominantly hydro each year can have 30-40% variability in generation output.

The following data refers to operational models only:

- Puget has 70 years of historical water flow data, however regulators direct them to use 50 years for modeling purposes.
- Puget uses 50 years of data and runs it through a system of models with scenario analysis to simulate each year and they take the median water flow for modeling purposes.
- They do not consider 'black swan' events in their planning. As the year progresses and their water flow data becomes more refined they take some years out of the original data set of 50 to tailor the flow forecast to actual conditions. For example, this year flows are lower than normal so they have stripped the top eight years of historical water flow out of the forecast.
- In order to more accurately determine their forecasts they track government sources of water flows for transparency.
- They purchase one forward curve for their price assumptions.
- Production co-efficient assumptions are determined by the generation resource team.
- In their operational models they do not account for climate change, but this is accounted for in their long-term planning models. Operational models look ahead 3 years.
- Models are audited by Internal Audit every six months. The modelers and the risk team meet weekly to review the model outputs and conduct a check on the models.
- Internal modeling processes have not changed significantly over time.

1. Corporate Overview

Company Address/Key Contacts

Salt River Project
1521 N. Project Drive
Tempe, AZ 85281-1298
(602) 236-5900
www.srpnet.com

Financial Snapshot ($USD)

Latest Fiscal Year:	April 2008
Revenue:	$2.7 billion
Domestic Revenues:	$2.3 billion
Export/Trade Revenue:	$0.4 billion[1]
Net Income:	($0.1 billion)
Fiscal Year End:	April
Employees:	4,431

Generation Capacity

Installed Capacity:	8,094 MW
Generation:	33,064 GWh
Mix:	
Sites:	6 coal-fires generating stations 4 natural gas-fired generation stations 1 nuclear generation stations 5 dams and 3 hydro-electric facilities

- SRP purchases 812 MW of power through contracts for traditional power and 210 MW of hydroelectric power. The amount of power purchased is lower in the winter months.

Company Overview

From SRP Website www.srpnet.com:

- The Salt River Project (SRP) is the collective name used to represent two separate entities:
  - Salt River Project Agricultural Improvement and Power District - A political subdivision of the state of Arizona that provides electricity to retail customers in the Phoenix area
  - Salt River Valley Water Users' Association - A private company that maintains and operates a water deliver system that delivers water to a service area in central Arizona
- The majority of this case study will discuss the practices of the Power District.

Ownership/Subsidiaries

- SRP is a political sub-division of the State of Arizona.

Core Strategy

[1] *Total revenues also include $14 million for water revenues.*

From SRP Website www.srpnet.com:

- "SRP delivers high-value electricity and water for the benefit of our customers, our shareholders and the communities we serve."

Demand-Side Management

From SRP 2009 Annual Sustainability Report Summary:

- SRP offers 20 energy-efficiency and demand-reduction programs to help customers reduce energy use and save money. In FY09, these programs resulted in annual aggregate energy savings of more than 348,000 megawatt-hours.

Regulatory and Planning Framework

From SRP Website www.srpnet.com:

- SRP is a political subdivision of the state of Arizona and is designated as a quasi-municipality. As a quasi-municipality it is not regulated by the Arizona Corporation Commission, the regulator of investor-owned utilities.
- SRP is governed by a Board of Directors which establishes policies for management and has the responsibility of overseeing the conduct of business affairs. Under Arizona law, the Board also has the exclusive authority to establish electric prices.

Environmental - Emissions

From SRP 2009 Annual Sustainability Report Summary:

- More than 20% of SRP's energy is produced without greenhouse-gas emissions.

2. Risk Governance

Risk Governance

From SRP 2009 Annual Report:

- "The District has an Energy Risk Management Program to limit exposure to risks inherent in retail and wholesale energy business operations by identifying, measuring, reporting and managing exposure to market, credit and operational risks."
- The Energy Risk Management Program's policy and risk "appetite" is approved by the Board of Directors and is overseen by a Risk Oversight Committee (ROC). The Risk Oversight Committee is composed of SRP management executives and is chaired by their equivalent of a CFO and includes the firm's other Associate General Managers.
- Under the ROC is the Energy Risk Management department (ERM) whose role is to identify, measure, and report commodity trading positions associated with SRP's commodity trading activity. ERM operates under the purview of the ROC, which gets its direction from the SRP Board and sets the limits and guidelines. ERM monitors, manages and reports on SRP's trading positions to ensure trading activities are in compliance. ERM also acts as SRP's Middle Office.
- The ERM reports commodity positions to the ROC every month or as requested. The ROC reviews risk reports, authorizations, credit limits, position limits, stop losses, VARs, etc. and makes decisions delegated to the ROC under the Board's direction. ERM also reports to a quarterly ROC which consists of SRP's General Manager (equivalent to a CEO), President and Vice President of SRP's Board. The General Manager has the authority to appoint members of the ROC. ERM also reports to the SRP Board semi-annually or as needed if the topic is one that requires Board level approval. Additional market position reports and risk assessments are provided daily to the managers of ERM and the Trading group.

Middle Office

- The ERM has 13 dedicated professionals each focus on one of credit, market or operational risk. ERM has an independent reporting structure to an executive manager who also oversees the Trading and Resource Planning areas (ERM is not a group within the Trading area but the manager of the trading area and the manager of ERM both report to an executive manager who also is a member of the ROC).
- The ERM reviews forecasting models that are created, but it doesn't have an audit role. It uses part of the forecasting models for use in its own software which contributes to the wholesale trading activities
- At SRP the traders use OD WebTrader and ERM uses Sungard's Aligne software as well as Great Plains and Cognos.
- SRP's front, middle and back offices are audited by both internal and external auditors each year.
- SRP's risk governance and middle office structure were first established in 1997-98. While SRP's risk appetite as defined by the SRP Board has not changed significantly, SRP has expanded hedging programs to additional commodities as the market has evolved.

3. Power Risk Management

Risk Management Policy

- Risk identification
  - The ERM group has a procedures manual that defines each type of risk and responsibilities.
  - There is a Complex Deal Committee that meets on a regular basis to assess major trades. The committee includes members from the front, middle and back office to review potential new counterparties, agreements, regulatory issues, etc. to ensure each area is involved in and can weigh in on activities according to their area of expertise.
- Risk measurement
  - There are limits in place for various commodities – VaR thresholds and stop loss limits and counterparty limits
  - Limits are set by commodity. Additionally, there are individual trader limits set by commodity, term, and notional dollar amount.
  - If a threshold is passed, the appropriate level of management is notified as defined in the ERM Policy.
- Risk mitigation
  - Purchase options and collars – they have a lot of financial hedges as opposed to physical trading.
  - Purchase a lot of ISDA hedges.
  - SRP does not purchase weather derivatives.
  - SRP hedges further into the future now than they did five years ago. They have also expanded into hedging several new commodities.
  - The ROC and/or Board has the authority to change policies at any time based on market conditions or the company's risk appetite. In the event of a violation of the risk policies, executive management is notified immediately and the ROC is notified at its next scheduled meeting.
- Risk reporting
  - There are daily risk reports that measure and report various credit, market and operational risks. The reports are sent to the traders and several members of management each day to let them know when they are getting close to their limits. The market risk group also puts together several daily informational reports for traders and management.
  - On a monthly basis, or as requested, various risk reports are created and presented to the ROC, which includes summaries of the daily reports and aggregated lists such as the Top 10 counterparties, risk breakdowns by commodity trading activity, VaR reports on unhedged positions, etc. Additionally, on a quarterly basis, or as requested, various reports are created and presented to the Quarterly ROC. Further, on a bi-annual basis, or as requested, various reports are created and presented to the SRP Board.

4. Power Sales Management

Long-Term Energy Contracts

- SRP generates power to meet its retail load. Any excess power is available for sale in the wholesale market. Excess energy may be sold in the forward, day ahead or spot markets.
- As a quasi-governmental entity, SRP may enter into various long-term power sales contracts with governmental districts and smaller retail customers. Several of these are legacy contracts.
- Indices used include the Palo Verde power index, San Juan gas index and others.
- Contract prices are determined by a number of factors including indices, generation costs, market price forecasts, market risks, resource planning risks and regulatory risks. Prices aim to be below the index.
- Contracts are reviewed by several groups within the organization, including legal, accounting, resource planning, ERM, and regulatory affairs.
- If a contract is 5 years or longer it requires Board approval, which then also requires review by the ROC.

5. Forecasting Models

Modeling Approach
▪ n/a

1. Corporate Overview

Company Address/Key Contacts

Endesa Chile
Santa Rosa 76
833-0099 Santiago, Chile
(56-2) 6309000
www.endesa.cl

Financial Snapshot (converted to US$)

Latest Fiscal Year:	2008	**Long-Term Liabilities:**	$4,195 million US
Revenue:	$3,915 million US	**Equity:**	$2,994 million US
Net Income:	$620 million US	**Debt to Equity:**	
Fiscal Year End:	December 31	**Return on Equity:**	
Employees:	1,948	**Total Assets:**	$10,873 million US

Source: Endesa Chile 2008 Form 20-K (US$ in U.S. GAAP, pg. 12-13)

Exchange rate is based on Observed Exchange Rate at Dec. 31, 2008 of Ch$ (Chilean pesos) 636.45 per US dollar

Generation Capacity

Installed Capacity:	13,298 MW across South America, with 5,284 MW in Chile and 3,652 MW in Argentina
Generation:	59,859 GWh
Mix:	62% hydro, 38% thermal
Sites:	52 power plants, including 27 in Chile

Transmission

- Transmission is owned by a separate transmission company in Chile and most other South American countries where Endesa operates. Endesa previously owned the grid but under new regulations had to sell the transmission system about a decade ago. Generators have open access to transmission and transmission rates are regulated by state bodies in each country.

Company Overview

- The principal activity of Endesa Chile and subsidiaries is the generation and sale of electricity. They also provide consultancy and engineering services.
- Endesa Chile is the principal electricity generator in Chile, and also has significant operations in Argentina, Columbia, Peru and Brazil.

Ownership/Subsidiaries

- Empresa Nacional de Electricidad S.A. ("Endesa Chile") is a publicly held limited liability stock company incorporated under the laws of the Republic of Chile on December 1, 1943. The Company is commercially referred to as both Endesa and Endesa Chile.
- The company was state-owned until 1987 and the privatization through public share offerings was completed in 1989. Endesa Chile is one of the largest publically traded companies in Chile.
- In 1999, Enersis S.A. became controller of the company with a 60% shareholding of Endesa Chile's capital stock. Since October 10, 2007, the Italian energy company, Enel, and the Spanish construction company, Acciona, jointly hold 92.1% of the share capital of Endesa Spain, which in turns owns

60.6% of Enersis.

- Endesa Chile has several subsidiary companies operating in Chile, Argentina, Peru and Columbia and interests in projects in Brazil.

Key Performance Indicators

- Endesa Chile tracks a number of key performance indicators, financial and non-financial.

Regulatory and Planning Framework

- Endesa Chile is a publicly-traded company, regulated by the Chilean Superintendence of Securities and Insurance (Superintendencia de Valores y Seguros or "SVS") as well as by the United States Securities and Exchange Commission (SEC) since registering American Depositary Shares in 1994.
- Endesa Chile and subsidiaries participate in the generation and sale of electricity in four countries in South America, each with a different regulatory framework.
- The goal of the Chilean Electricity Law is to provide incentives to maximize efficiency and to provide a simplified regulatory scheme and tariff-setting process to establish objective criteria for setting prices. The regulatory system is designed to provide a competitive rate of return to stimulate private investment while ensuring the availability of electricity service throughout the country.
- In Chile, the National Energy Commission (CNE) calculate retail tariffs and wholesale prices, which requires the final approval of the Ministry of Economy, and prepares the indicative plan as a 10-year guide to system expansion. The SEF sets and enforces the technical standards of the system and the compliance to law. The Ministry of Economy also regulates the granting of concessions to electricity generation, transmission and distribution companies.

Environmental - Emissions

- The Company received a "Silver Class" distinction in the Sustainability Yearbook 2009, being placed among six electricity companies with the best sustainability performance.
- Nearly all facilities in South America have their environmental management system certified under the ISO 14001 standard.

2. Risk Governance

Risk Governance

- Endesa Chile is managed by its Executive Officers under the direction of a nine member Board of Directors, elected at an annual shareholders' meeting.
- Risk responsibility is in the office of Energy Management, and reports to the General Manager.
- Enterprise risk management ultimately resides in the parent company in Spain. The parent company has a Chief Risk Officer, there is not a CRO in Endesa Chile.
- There is a Risk Manager in the office of Energy Management, inside the middle office.
- Risk policy is part of Energy Management's commercial policy that is approved by the General Manager and the corporate Energy Management Committee. This includes approval limits required for different thresholds of contracts.
- The focus is on energy management and short and long-term contracts, not on trading.
- Understanding is the structure and policies have not changed much in the past five years, most were put in place 8-9 years ago.

Key Risks

In its *2008 Annual Report* (pg. 69-70), Endesa identifies its key risk factors:

- Regulatory Risks – All the legislations regulate the electricity sector of each country and impose obligatory compliance. However, there are interpretations as well as the provisions of the regulatory authority that are adapted to the complexity of the system and that could affect the general conditions of the business.

- Environmental Factors – In Chile, the sector is subject to environmental regulations requiring environmental impact assessments (EIA) or declarations (EID) to be approved for electricity generation projects for obtaining the environmental permit (environmental qualification resolution) necessary in order to start construction work. The other countries where Endesa Chile operates have similar regulations. Endesa Chile and its subsidiaries have adapted their projects and operations to the environmental regulations of the different countries where they operate and comply with these, including carrying out environmental investments over and above those required by the applicable environmental standards. As of December 31, 2008, 99% of the installed capacity of Endesa Chile and subsidiaries in Latin America was certified under the ISO 14001 international standard for environmental management systems. This translates into a better control and monitoring of aspects susceptible to generating an environmental impact, based on the principle of continuous improvement.

- Hydrology – A substantial part of the Company's operations are hydroelectric which means that it has a certain dependence on rainfall conditions in the zones and countries where it operates. The Company has designed its commercial policy to reduce the risk related to extremely-dry conditions, with sale commitments in line with the firm energy capacity of its generating plants in a dry year, giving preference to its better contracts and customers, and including contract clauses mitigating the risk in some contracts with non-regulated customers.

- Exchange risks – The Chilean peso and other currencies in which Endesa Chile and its subsidiaries operate have been subject to volatility against the US dollar. Historically, a large part of consolidated debt has been denominated in US dollars and despite a large portion of revenues being indexed to the dollar, the match may not always be perfect and the Company could be exposed to fluctuations in local currencies against the dollar.

- Value of long-term energy sale contracts – The Company faces an economic exposure with respect to market price fluctuations for certain basic products because of the long-term energy sales contracts we have signed. Generating subsidiaries have substantial obligations under long-term electricity sales contracts, whose prices fluctuate according to the exchange rate, the market price for electricity, the market prices of principal inputs, like natural gas, oil, coal and other energy-related products. It is impossible to introduce indexation formulas that correlate perfectly the changes in the market prices of these commodities, the exchange rate and the market price of electricity with electricity production costs. There may therefore be times when the price received under these contracts is below electricity production or acquisition cost. The Company does not use commodity derivatives for hedging its exposure to commodity price fluctuations.

- Natural gas shortage – The natural gas shortage in Argentina could continue to have a negative impact on some generating plants in that country, especially those that use natural gas as input. As a result of this shortage, in Argentina, gas-supply cuts have affected supplies to the combined-cycle plants, forcing them to operate with oil. This causes an increase in operating costs which, although financed by the whole system, ends up reducing the margin on contracts and spot market sales. In Chile, the Tal Tal plant of Endesa Chile and its subsidiary San Isidro purchase natural gas from their Argentine suppliers subject to the availability of this fuel. However, cuts in gas supplies from Argentina have been replaced with oil, affecting both the production volume and the operating costs of these plants, a situation that will be mitigated from the second half of 2009 with the availability of liquefied natural gas at the new Quintero terminal.

Hydrological:

- Approximately 62% of consolidated installed generation capacity is hydroelectric. Accordingly, extreme hydrological conditions affect the business and may have a substantial influence over results. During periods of drought, thermal plants, that use natural gas, fuel oil or coal as a fuel, are dispatched more frequently. Operating expenses increase during these periods and, depending on the size of commitments, they may have to buy electricity from other parties in order to comply with contractual supply obligations. The cost of these electricity purchases in the spot market may exceed the price at which they sell contracted electricity, thus producing losses from those contracts.
- Generation subsidiaries have a commercial policy in order to limit the potential impact of interruptions to the ability to supply electricity to our customers, including those caused by droughts, interruptions in gas supply and prolonged plant stoppages. Pursuant to this policy, a level of contracts is determined for each generation company by reducing the hydrological risk to acceptable levels, assured by a degree of statistical reliability of 95%. Any contracts for volumes that exceed this 95% level are required to include clauses transferring the risk of interruptions and its related costs to the customers. Notwithstanding this risk-reduction policy, a prolonged drought will adversely affect results.
  Source: Risk Factors in Endesa Chile 2008 Form 20-K, pg. 16-17

Middle Office

- The "middle office" is within Energy Management. Each country has a front office and middle office. Approximately 20-25 personnel in Chile operate as the middle office, providing policies, controls and reviews of contracts, prices and fuel.
- The middle office reviews the mathematical models for energy management.
- While the middle office has a methodology to evaluate credit risk, financial risks and policies are evaluated in Finance.
- Provide monthly reports to the General Manager and executives related to energy management, as well as to the Chief Risk Officer in Spain.
- The middle office is subject to internal review from the parent company.
- The structure has been in place for around a decade and has not changed in the past five years.

3. Power Risk Management

Risk Management Policy

- Endesa Chile has documented definitions of risk and how risks are measured and managed.
- Risk management policies are documented in terms of what the company can do and not do, as well as limits of approval.
- There are various risk limits such as volume, tenor and counterparty limits within each country.
- Risk analytics include value at risk, scenario analysis and stress testing. VaR limits are decided by the Committee.
- Analysis is focused on margin at risk and EBITDA risk. Reports on the position of VaR and EBITDA risk are done monthly looking at the present year and next year.

Commodity Price Risk

- Endesa is primarily hydro based, enabling them to do more natural hedging.
- Endesa Chile is exposed to price fluctuation risk on some commodities, basically fuel purchases for electricity generation and also energy trading transactions in the local markets. Looking forward to reduce risks of extreme drought conditions, the company has a trading policy that defines sales commitment levels consistent with its firm energy capacity of its generating power plants in a dry condition, and includes risk mitigation clauses in some contracts with non-regulated customers. *(Endesa Chile Form 6-K, January 2010)*
- The Company has commodity contracts that are unique, due to their long-term nature and complexity. In establishing the fair value of contracts management makes assumptions using available market data and pricing models. Factors such as commodity price risk are also included in the fair value calculation. Inputs to pricing models include estimated forward prices of electricity and natural gas, interest rates, foreign exchange rates, inflation indices, transmission costs, and others. These inputs become more difficult to predict and the estimates are less precise, the further out in time these estimates are made. As a result, fair values are highly sensitive to the assumptions being used.

Source: Endesa Chile Form 20-K pg. 147

Derivative Financial Instruments and Hedges

- The Company is exposed to the impact of market fluctuations in the price of electricity, natural gas, petroleum, coal, and other energy-related products, interest rates, and foreign exchange rates. The Company has policies and procedures in place to manage the risks associated with these market fluctuations on a global basis through strategic contract selection, fixed-rate and variable-rate portfolio targets, net investment hedges, and financial derivatives. The Company has chosen to apply hedge accounting under US GAAP for derivatives and non-derivative instruments that meet the criteria for hedge accounting under SFAS 133, the accounting treatment for these instruments depends on whether they qualify as fair value, cash flow or net investment hedges. Derivatives that do not meet hedge criteria are accounted at fair value with changes in fair value recorded in earnings.
- The Company has generation and distribution commodity contracts that meet the definition of a derivative under SFAS 133 and are required to be accounted for at fair value. These derivative contracts were evaluated for qualification under the normal purchase and sale exception. A number of contracts could not qualify under such exemption because they had prices tied to an unrelated underlying such as a local and/or foreign inflationary index.

Source: Endesa Chile Form 20-K pg. 146-147

- Endesa Chile does not purchase weather derivatives/insurance. Not a common product.

4. Power Sales Management

Long-Term Energy Contracts

- In Chile, the Company has long-term contracts with industrial clients and regulated contracts with distribution companies that are 10-15 years. The average term of long-term contracts is 5 to 7 years.
- Long-term contracts are generally fixed price with an escalator. The escalator is primarily based on fuel prices as well as inflation in some countries.
- Mostly managing energy supply within each country where they operate.
- In Chile, close to 70% of power is sold in contracts, with approximately 30% spot market. In other countries, the percentages are different.
- The middle office reviews that the front office is making the offer according to policies.
- Contract approval process depends on size thresholds, with larger contracts going to the executive level for approval.

Endesa Chile Consolidated Physical Sales by Type of Customers

	GWh	*% of Sales Volume*
Regulated customers	23,779	42.7
Non-regulated customers	14,503	26.0
Electricity pool market sales	17,453	31.3
Total Electricity Sales	55,734	100.0

- In general, in the countries in which they operate, the potential for contracting electricity is related to the volume of electricity demand. Customers identified as small volume-regulated customers, such as residential customers, subject to government regulated electricity tariffs, must purchase electricity directly from a distribution company. These distribution companies, which purchase large amounts of electricity for small residential customers, generally enter into contractual agreements with generators at a regulated tariff price. Those identified as large volume industrial customers also enter into contractual agreements with energy suppliers. However, such large volume industrial customers are not subject to the regulated tariff price. Instead, these customers are allowed to negotiate the price of energy with generators based on the characteristics of the service required. Finally, the market pool, where energy is normally sold at the spot price, is not carried out through contractual agreements.

- The specific energy (measured in GWh) consumption limit for regulated and non-regulated customers is country specific. Moreover, regulatory frameworks often require that regulated distribution companies have contracts to support their commitments to small customers and also determine which customers can purchase energy in electricity pool markets.

- Under normal hydrological and fuel conditions, regulated and non-regulated customers carry out their commercial relationships by means of contracts. The electricity pool market sales are not governed by contracts, but instead comply with pool market operations.
Source: Endesa Chile Form 20-F, June 2009, pg. 27

Endesa Chile Consolidated Physical Sales by Customer Price Segment

	GWh	*% of Sales Volume*
Contracted	38,282	68.7
Non-contracted	17,453	31.3
Total Electricity Sales	55,734	100.0

- In terms of expenses, the primarily variable costs involved in the electricity generation business, in addition to the direct variable cost of generating hydroelectric or thermal electricity such as fuel costs, are energy purchases and transportation costs. During periods of relatively low rainfall conditions, the amount of thermal generation increases. This not only involves increasing the total cost of fuel, but also the cost of transporting that fuel to the thermal generation power plants. Under drought conditions, electricity that is contractually agreed to provide may exceed the amount of electricity that the company is able to generate, requiring them to purchase electricity in the pool market in order to satisfy contractual commitments. The cost of these pool market purchases may, under certain circumstances, exceed the price at which they sell electricity under contracts, and result in a loss. They attempt to minimize the effect of poor hydrological conditions on our operations in any year primarily by limiting contractual sales requirements to an amount that does not exceed the estimated production in a "dry year." In determining estimated production in a dry year, they take into account available statistical information concerning rainfall and water flows, and the capacity of key reservoirs. In addition to limiting contracted sales, they may adopt other strategies such as installing temporary thermal capacity, negotiating lower consumption levels with unregulated customers, negotiating with other water users and including pass-through costs clauses in contracts with clients.

Source: Endesa Chile Form 20-F, June 2009, pg. 27-28

- In Chile, sales may be made to final customers under contracts or to other generation companies, on a spot basis. Generation companies may also be engaged in contracted sales among each other at negotiated prices. Historically, sales to distribution companies for resale to regulated customers have been made through contracts at regulated prices ("node prices") in effect at the relevant locations ("nodes") on the interconnected system through which such electricity is supplied. Nevertheless, since 2005 all new contracts between generation and distribution companies for the supply to regulated customers must be the result of international bids which have a maximum regulated offer price equal to 56% over the average price paid by the unregulated customers at the time that the bid is made. If a first bid is unsuccessful, authorities may increase this maximum price by an additional 15%. The bids are awarded on a minimum price basis. The price associated with these bids will be transferred directly to final users, replacing the current regulated price regime. During the life of the contract, the energy and capacity prices will be indexed according to formulas set forth in the bid documentation and linked to fuel, investment and other costs of energy generation. Under the bid system all distribution companies will have electricity contracts from 2010 onwards.

- Regulated customers are those with a maximum consumption capacity not exceeding 0.5 MW. Customers between 0.5 and 2 MW may choose their status as regulated or unregulated. Customers with capacity needs over 2 MW are unregulated. Two node prices are paid by distribution companies: one for capacity and the other for energy consumption. Node prices for capacity are calculated based on the marginal cost of increasing the existing capacity of the electricity system with the least expensive dispatch by any generating facility.

Source: Endesa Chile Form 20-F, June 2009, pg. 46-47

5. Forecasting Models

Modeling Approach

Understanding of Endesa's model approach:

- Hydrological models generally look at 40-60 years of historical data. Models simulate driest or wettest years and many variables.
- Plan is for 95% probability of water flows, not the worst case scenario.
- Models do not take into account climate change at this stage.
- Stochastic/probabilistic models running a few thousand scenarios.
- For price forecasts, look at forward curves in each country as a reference. Price forecasts are developed internally.

Types of Models

- Mix of internal and external model components, but the model combining all parts is designed internally.
- Approximately 5-6 personnel in Chile are specifically concentrated on modeling, plus modelers in each country where they operate.
- The basic model mechanics has not changes in the past five years, but more sophisticated in variables and scenarios.

Meridian Energy Limited (New Zealand)

1. Corporate Overview

Company Address/Key Contacts

Meridian Energy Limited (New Zealand)
33 Customhouse Quay
PO Box 10840
Wellington, New Zealand 6143
+04 381 1200
www.meridianenergy.co.nz

Financial Snapshot ($NZ)

Latest Fiscal Year:	2009	**Net Debt:**	$NZ 1,126 million
Revenue:	$NZ 1,892 million	**Equity:**	$NZ 4,285 million
Net Income:	$NZ 89 million	**Debt to Equity:**	21/79
Fiscal Year End:	June 30	**Return on Equity:**	2.1%
Employees:		**Total Assets:**	$NZ 7,177 million

Source: Meridian Energy 2008 Annual Report

Exchange rate June 30, 2009 $NZ 1.55 = $US 1.00

Generation Capacity

Installed Capacity:	2,693 MW
Generation:	12,237 GWh
Mix:	96% hydro/ 4 % wind
Sites:	12 hydro power stations and three wind farms

Transmission

- In New Zealand, transmission is owned and operated by a separate company.

Company Overview

- Meridian Energy is the largest state-owned electricity generation company in New Zealand, providing around 30% of the country's total generation. Meridian also retails electricity to 187,000 customers.
- Core business is the generation and retailing of hydroelectricity.

Ownership/Subsidiaries

- Meridian Energy is a state-owned enterprise of the Government of New Zealand under the *State-Owned Enterprise Act 1986.*
- Operates primarily in New Zealand and through subsidiaries and joint ventures has operations in Australia, the U.K. and Spain.

Core Strategy

- Focused in delivering shareholder value and producing energy in the most reliable, cost-effective way with the least impact on the environment.

Key Performance Indicators

- Meridian reports on economic, environmental and social performance, using G3 Sustainability Reporting Guidelines produced by the Global Reporting Initiative.
- Annual performance scorecard compares targets to actuals and includes indicators of: financial results, financial ratios, generation performance, wholesale and retail segments, ventures portfolio, capital expenditures, GHG emissions, and health and safety.

Regulatory and Planning Framework

Regulator: Electricity Commission in New Zealand

Environmental - Emissions

- Meridian has a Greenhouse Gas Measurement and Management Policy that sets out initiatives and targets to reduce emissions.
- In 2008-2009, Meridian initiated the development of a climate change adaptation plan to assess the possible outcomes and longer term impacts of climate change on water and wind resources, determine additional information required to improve their understanding, and initiate appropriate adaptive responses.

2. Risk Governance

Risk Governance

- The Crown Companies Monitoring and Advisory Unit (CCMAU) provides the liaison between the company and the shareholding Ministers. The Board provides direction to the company and operates under the CCMAU Owner's Expectation Manual. The CCMAU sets out the Ministers' expectations of the Board including reporting, accountability and performance.
- The Board's Audit and Risk Committee's responsibilities include ensuring the efficient and effective management of all business risks and compliance.

Source: Meridian Energy Annual Report 2009, pg. 20- 24

- Meridian has a systematic approach to risk management. It regularly identifies, assesses and manages key risks that may impact the Company's ability to achieve its objectives and/or protect its people, assets or reputation. As set out in Meridian's Risk Management Policy, Meridian adopts a managed approach to risk that encourages appropriate risk taking, acceptance or avoidance, depending upon the consequences and likelihood of risks' occurrence, and the potential associated benefits or opportunities.
- Risk management is ingrained in strategic and operational activities including business planning, investment analysis, portfolio and project management and day-to-day operations. Meridian's policies, including the Delegation of Authority policy, provide a framework for decision making and risk management. In relation to financial risks around treasury transactions, the Board has approved principles and policies that specify who may authorize transactions and segregates the duties of those carrying them out. The Audit and Risk Committee has overall responsibility for ensuring management's risk management framework, including policies and procedures, are appropriate and that they appropriately identify, consider and manage risks. The Audit and Risk Committee reviews the Company's risk profile regularly.
- The Audit and Risk Committee also receives reports on the operation of risk management policies and procedures. The internal audit function reports to the Audit and Risk Committee on the extent and effectiveness of Meridian's risk management program. The Committee reports this information to the Board.
- Internal audit in Meridian provides independent assurance to the Board and management that key risks are being adequately managed and the company's internal control framework is operating effectively. Meridian's internal audit function is provided via an outsourced arrangement with Ernst and Young, managed by Meridian's Group Risk Manager. The internal audit function reports to the Board through the Audit and Risk Committee. Meridian's internal audit function is independent from the activities and operations it audits including risk management systems and has unrestricted access to Meridian records and staff.

Source: Meridian Energy Annual Report 2009, pg 75-76

- In recent months, the company completed an organizational restructuring. This created a Strategy and Finance business unit of approximately 12 personnel and Risk is part of this group.
- Each business unit identifies its top ten risks and the risk group consolidates this into a top ten risk profile for the company.

- The Middle Office is responsible for measuring revenues, monitoring risk, maintaining the forecasting tools, optimizing reservoir use to maximize revenues, wholesale trading deal valuation, guidance on portfolio design, transactional bias required to achieve best risk /revenue position and maintaining the risk management policy.
- The Middle Office includes three analysts looking after risk and revenue management, two analysts focused on Transmission, two model development analysts and three analysts focused on short-term generation control, hydrological management and weather forecasting.
- The Middle Office has autonomy in looking after the core optimization model. The Strategy group runs similar models where input assumptions are checked an model outputs are cross-validated.
- Generate weekly performance reports, and a monthly performance and risk management report that goes to the Board and management. The Board owns the risk parameters and risk appetite for the company.
- Subject to internal audit reviews during the year, and every few years, an external audit of trading and wholesale trading policy and methodology.
- The Middle Office has not changed significantly in the past five years, and the recent reorganization has not significantly affected this office.

3. Power Risk Management

Risk Management Policy

- Meridian's activities expose it to a variety of financial risks: market risk (including electricity and other price risk, currency risk, interest rate risk, cash flow risk) credit risk and liquidity risk.
- Meridian's overall risk management program focuses on the unpredictability of financial markets and the electricity spot price and seeks to minimize potential adverse effects on the financial performance and economic value of the Group.
- Meridian uses sensitivity analysis to measure the amount of risk it is exposed to for: price risk, foreign exchange risk, interest rate risk and aging analysis for credit risk.
- Risk management for interest rate risk and currency risk is carried out by the Group Treasury department under policies approved by the Board.
- Electricity price risk management is carried out by a centralized electricity risk management group. These groups identify, evaluate and economically hedge financial risks in close co-operation with the Group's operating units. Hedges are undertaken on an economic basis based on net exposures and cash flows. The Board provides written principles for overall risk management, as well as policies covering specific areas such as electricity price risk, interest rate risk, foreign exchange risk and credit risk.

Source: Meridian Energy Annual Report 2009, pg. 112-113

- Meridian maintains a detailed wholesale trading and hedging policy.
- The risk management framework uses a market optimization model to create up to 150 scenarios which represent the plausible range of possible generation, price and revenue outcomes. The forecast revenue distribution is presented as annual financial year cumulative probability distributions ("S curves"). The mean of the distribution is typically used for revenue planning purposes and the 5%ile of the distribution is used as part of Meridians "Revenue at risk" risk management framework. This 5%ile is compared to two board approved financial risk parameters which represent minimum revenue requirements.
- Financial limits are reviewed regularly (quarterly) and set after considering capital expenditure, OPEX and credit rating requirements. Changes in the 5%ile revenue distribution and relative change to the financial risk parameters are reported to the Board on a monthly basis.
- The Company also maintains a set of physical risk parameter to manage specific locational, hydrological and profile risks.

Commodity Price Risk

- Meridian is exposed to movements in the spot price of electricity arising through the sale and purchase of electricity to and from the market. Meridian manages this exposure by entering into contract for differences (CfD's) to manage the net risk. Meridian does not enter into CfD's for speculative purposes.
- It is Group policy to manage this risk on a net basis by entering into CfD's which swap receipt (payment) of spot electricity prices based on a specified volume of electricity with fixed electricity payments (receipts) for an equivalent volume. Cash settlements are made on these instruments on a monthly basis and impact income on an accrual basis.
- The CfD's include both forward contracts traded with reference to the energy hedge market and bi-lateral CfD's with other electricity generators and major customers. Meridian estimates both expected generation and electricity purchase requirements and determines its net position of generation less sales. Based on this net position, Meridian enters into CfD's to protect against price volatility within trading parameters set and monitored by the Board. Although Meridian considers itself economically hedged in relation to electricity price risk, it has decided, effective 1 January 2009 to no longer meet the requirements to enable it to adopt hedge accounting for any of its CfD's. Consequently, for accounting purposes, from 1 January 2009 all of the CfD's are classified as held for trading with

movements in fair value recognised in the income statement.

- For the first six months of the year and the comparative reporting period Meridian applied hedge accounting to a portion of the hedge book. These contracts were considered as part of an effective cash flow hedge relationship with the effective portion of the gains and losses deferred in a cash flow hedge reserve until the forecast electricity sales/purchases designated as the hedged item are transacted. Upon cessation of hedge accounting the balance in the cash flow hedge reserve is amortised as contract volumes expire over the remaining life of the respective contracts. The aggregate notional volume of the outstanding electricity derivatives at 30 June 2009 is 77,860 GWh.

Source: Meridian Energy Annual Report 2009, pg. 113-114

Derivative Financial Instruments and Hedges

- Meridian uses derivative financial instruments to hedge certain risk exposures such as: foreign exchange contracts and options, cross currency interest rate swaps, interest rate swaps, and electricity CfD's to hedge certain risk exposures.
- No weather derivatives.

Source: Meridian Energy Annual Report 2009 (details in financial statement note 26)

4. Power Sales Management

Long-Term Energy Contracts

- Meridian has one major long-term contract. Most sales are spot market with the remaining wholesale trading. Majority of contracts are approximately three years.
- In October 2007, Meridian and New Zealand Aluminum Smelters (NZAS) entered into an electricity price agreement (which includes a CfD) based on 572 MW of continuous consumption at the smelter. The agreement is for a period of up to 18 years and will take effect from January 2013. Under an existing contract which expires in 2012, Meridian is responsible for delivered energy supply to the smelter. This means Meridian is responsible for the electricity, its quality, and its transmission to the smelter. The new agreement is a pricing agreement rather than a supply agreement. NZAS will be responsible for purchasing electricity from the national market itself, and Meridian will provide NZAS with price certainty for that electricity. The agreed base price under the new agreement is significantly higher than under the current electricity supply contract. This base price is subject to escalation with reference to a multi-year average market price for electricity in New Zealand, the world price for aluminum (as determined by an independent benchmark), and a component as a proxy for price inflation.
- Meridian considers this formula will best ensure that the electricity price NZAS pays will remain competitive for electricity demand of the unique type created by the smelter, while recognizing both the commodity-price driven cycles of NZAS's business environment and the wholesale electricity price cycles to which Meridian is exposed.

Source: Meridian Energy Annual Report, pg. 93

- Meridian has some power purchase agreements with independent power producers, but these are relatively small.

5. Forecasting Models

Modeling Approach

- Hydrological data goes back close to 80 years.
- Worst case scenario in planning process uses the worst forecast revenue sequence to identify the largest 1-3 month revenue loss and/or cash flow risks due to market and hydrological conditions. The 5th percentile of the revenue distribution is used in the risk management framework for analyzing poor financial year outcomes.
- Not directly looking at climate change.
- Power and supply looks at trends in the short-term market, and long-term models are looking at annual data and are much broader.
- Core processes on running the models are documented.
- Price forecasting looks at supply and cost curves of the plants and develops a marginal cost curve. Generally, the models forecast an average outcome.
- Attempt to separate who owns the assumptions (e.g., state of the market, pricing) from who runs the model. One person is responsible for a quarterly update of the assumptions.

Types of Models

- The internal model is a least cost model and optimization model is probabilistic and examines many scenarios.
- Rely on internal and external experts to look after and maintain the models.

F

Appendix F: Manitoba Hydro Power Sales and Operations 2009 Document

Now Is The Time – A Strategic Opportunity

Global concern over climate change has created a unique time-sensitive opportunity for Manitoba Hydro. In exchange for advancing the development of 1800 MW of new hydro-electric projects in northern Manitoba and a long-term sale commitment for a portion of newly available surplus renewable energy, US customers will commit to build the next major new interconnection with Manitoba.

This opportunity benefits both Manitoba and Manitoba Hydro's US customers. Manitoba benefits from the economic, environmental and social benefits of new hydro construction and increased more certain market access for surplus electricity sales. Transmission reliability and energy security are also enhanced. Revenues from the sale of the additional power will continue to keep rates lower in Manitoba than they would otherwise be. Aboriginal participation in the projects will provide resource revenue, employment, business opportunities and capacity building in northern communities. The additional surplus hydro-power produced will offset generation that would otherwise come from predominately carbon based resources in the US. This displacement will benefit the environment.

In the US Manitoba Hydro's export customers will benefit from a supply of affordable renewable energy that is needed in response to the evolving requirements of a carbon free world. And in order to make Manitoba's abundant supply of hydro-electricity available to them, Wisconsin Public Service and Minnesota Power have committed to building a major new interconnection in order to increase their access to Manitoba's renewable surplus.

This commitment to build a new interconnection with Manitoba is very significant to the optimum development of Manitoba's hydro-electric and wind resources. By the middle of this century most of the remaining developable hydro-electric sites will be needed to meet the growing provincial requirement for dependable supplies of power. Following that, other clean dependable supplies will be required. A consequence will be a large increase in the availability of surplus non-dependable energy that could be exported. However to enable those exports, additional transmission interconnection capability in the order of 3,000 MW to 4,000 MW will be needed.

Geographically, Manitoba is on the northern periphery of North American electric grid. Markets of sufficient size, capable of absorbing Manitoba's potential energy surpluses are far away, ranging from 700 km to Minneapolis to 1,700 km to Toronto to 2,900 km to Las Vegas. Transmission access to these markets is feasible but it requires a commitment and investment of billions of dollars by others in major transmission lines. WPS and MP have indicated a willingness to make that commitment.

Convincing others to construct major interconnections is a long and uphill challenge made even more difficult on this project given its international nature. However with the threat of climate change, renewables have become the jet stream on which major new transmission is being justified and is being built. If Manitoba acts now and commits to the development of Keeyask and Conawapa, it can leverage the Manitoba advantage of abundant renewable hydro-electricity into a major new interconnection which will provide benefits to the Province in perpetuity. Failing to act will result in a lost opportunity that may never come again.

Power Sales and Operations
Manitoba Hydro
ADC/090619

G

Appendix G: Manitoba Hydro's Long-Term Contracts for Export Sales

In this section, we present a summary of MH's existing long-term contracts together with the long-term contract summary provided by MH. The material in this section is MH's trade secret and confidential material.

mH
4.

	Counterparty	Capacity (MW)	Capacity Factor	Type of Contract	Start Date	End Date	Capacity Price (2009US$ / MWh)	On-Peak Energy Price (2009US$/ MWh)	All-In Price (2009US$/ MWh)	Escalator
1.	MP	[redacted]	[redacted]	System Participation	05/01/05	04/30/09	[redacted]	[redacted]	[redacted]	[redacted]
1.	MP	[redacted]	[redacted]	System Participation	05/01/09	04/30/15	[redacted]	[redacted]	[redacted]	[redacted]
2.	NSP	[redacted]	[redacted]	System Participation	05/01/05	04/30/15	[redacted]	[redacted]	[redacted]	[redacted]
3.	NSP	[redacted]	[redacted]	Diversity Exchange	05/01/95	04/30/15	[redacted]	[redacted]	[redacted]	[redacted]
4.	NSP	[redacted]	[redacted]	Diversity Exchange	11/01/96	10/31/16	[redacted]	[redacted]	[redacted]	[redacted]
5.	OTP	[redacted]	[redacted]	System Participation	05/01/00	04/30/10	[redacted]	[redacted]	[redacted]	[redacted]
6.	GRE	[redacted]	[redacted]	Diversity Exchange	05/01/95	04/30/15	[redacted]	[redacted]	[redacted]	[redacted]
7.	MMPA	[redacted]	[redacted]	System Participation	05/01/00	04/30/09	[redacted]	[redacted]	[redacted]	[redacted]
7.	MMPA	[redacted]	[redacted]	System Participation	05/01/09	04/30/12	[redacted]	[redacted]	[redacted]	[redacted]
8.	SMMPA	[redacted]	[redacted]	System Participation	04/01/08	03/31/13	[redacted]	[redacted]	[redacted]	[redacted]

Source: Manitoba Hydro

Note: the numeric references in the table above relate to the summaries provided below.

The following summary is directly from Manitoba Hydro.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

MH 1, 2, 4

KPMG

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

#

2.4.

6-4

KPMG

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

MH
1., 2., '

KPMG

[redacted]

2.4

G-6

H

Appendix H: Manitoba Hydro Term Sheets for Export Power Sales

MH has signed term sheets with Northern States Power, Minnesota Power and Wisconsin Public Service Corporation that are in various stages of negotiations for definitive power sale agreements. In this section, we present a summary of MH's term sheets together with the summary provided by MH. The material in this section is MH's trade secret and confidential material.

KPMG

2.,4.

	Counterparty	Capacity (MW)	Capacity Factor	Type of Contract	Start Date	End Date	Capacity Price (2009US$ /MWh)	On-Peak Energy Price (2009US$/ MWh)	All-In Price (2009US$/ MWh)	Escalator
1.	NSP	375/500[1]	[redacted]	System Participation	05/01/15	04/30/25	[redacted]	[redacted]	[redacted]	[redacted]
2.	NSP	350	[redacted]	Diversity Exchange	05/01/15	04/30/25	[redacted]	[redacted]	[redacted]	[redacted]
3.	MP	250	[redacted]	System Participation	05/01/22	04/30/25	[redacted]	[redacted]	[redacted]	[redacted]
4.	WSP	500[2]	[redacted]	System Participation	06/01/18	05/31/32	[redacted]	[redacted]	[redacted]	[redacted]

Source: Manitoba Hydro

MH MH MH MH MH

Note: the numeric references in the table above relate to the summaries provided below.

[1] *375MW May1, 2015 to April 30, 2015 and 500MW for period May 1, 2021 to April 30, 2025*

2. [redacted] MH

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

M#
1,2,4

KPMG

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

2.,4.

[redacted]

- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

MH
1.,2.,4.

Appendix I: Manitoba Hydro Approvals Process for Long-Term Power Sales

In this section, we describe MH's long-term power sales approvals process and evidence of this process being followed.

Summary of Policy Framework and Procedures for Long-Term Contract Sales[1]

Current policy and procedures that apply to long-term contract sales are:

- Management Control Plan
- Contract Documentation and Review Procedure
- Generation Planning G195

Relevant policy and procedure requirements are summarized below:

- Volumes available for long-term energy sales must conform to the Dependable Energy criteria policy. The long-term dependable supply is based on the Power Resource Plan.
- Long-term sales that don't require new generation may be entered into if it is determined that sufficient capacity and surplus dependable energy are available from the existing system.
- Long-term sales requiring new generation would not be entered into without following internal assessment processes and obtaining the appropriate corporate approvals.
- Pricing should reflect at a minimum the expected value as determined by the long-term price forecast prepared by Resource Planning and Market Analysis Dept.
- Pricing lower than the expected value outlined in the long-term price forecast must be approved by the Division Manager, Power Planning.

[1] *Source: MH document*

- Supply and pricing must be verified with the Market and Customer Information Analysts, Export Power Marketing and may include discussions with Resource Planning and Market Analysis Dept. and Power Trading departments where appropriate.

- Proposed terms and conditions, prior to final negotiations, must be reviewed concurrently with:

  - Contract Administration, Export Power Marketing
  - Law Department
  - Transmission Access, Export Power Marketing
  - Manager, Business Services, Power Supply and Operations
  - Manager, Power Trading

- The Departments are to follow a sign off document acknowledgement that they have had an opportunity to review and provide their comments.

- The statutory purpose of the Manitoba Hydro Act includes: market and supply power to persons outside the province on terms and conditions acceptable to the Board.

- In addition, the Manitoba Hydro Act requires Order in Council approval prior to entering into any export commitments that would require the construction of new generation.

We reproduce, as an example of the approvals process being followed, two MH Board minutes evidencing that term sheets for proposed long-term power sales were brought to the MH Board's attention:

1. Board minute 791-08-06 dated 22 May 2008:

<u>791-08-06</u>

Messrs. Adams and Cormie entered the meeting and gave a presentation on the Term Sheets recently signed with [redacted] and with	**Update on Export Power Term Sheets**

MH 1

[redacted], and the potential implications for future hydro-electric development in Northern Manitoba.

The presentation was received as information. The Board requested additional information in a number of areas (Schedule "A" to Minute No. 791-08-11 below). It was agreed that the Corporation in consultation with its stakeholder needs to develop a plan to explain the magnitude of the developments, opportunities and risks to the general public.

Note: KPMG followed up with MH regarding the MH Board's request for additional information pertaining to the export power term sheets. The additional information requested on the export power term sheets appears in Schedule A to Minute No. 791-08-11 and is reproduced below:

Schedule "A" to
Minute No. 791-08-11

Questions and Tasks Taken Under Advisement

1. Prepare a financial analysis of proposed Term Sheet sales and associated proposed new generating and transmission facilities, comparing the Corporation's Operating Statement with and without the sales

2. Provide a description of land that will be flooded at Keeyask, how it is currently used and plans to mitigate any damage

3. Prepare a spreadsheet that shows all generating and transmission projects proposed and underway

4. In conjunction with stakeholder, prepare a plan

to explain to the general public the magnitude of the developments, opportunities and risks of Term Sheet sales

5. Provide Board Member with a copy of the materials on IFRS that will be going to the Audit Committee

6. Provide details on new [redacted] lobbyist for PCN MH 1

7. Review Aboriginal employment targets in light of additional employees who have self-declared themselves as Aboriginal

2. Board minute 779-06-02 dated 16 November 2006

<u>779-06-02</u>

K.R.F. Adams and D. Cormie entered the meeting and briefed the Board on a Term Sheet signed with [redacted] which sets out the significant terms for a Power Purchase Agreement and a seasonal Diversity Sale Agreement during the period 2015 to 2021.

[redacted] MH 1

MH 1.

The presentation was received as information.

J

Appendix J: Detailed Scenario Runs

This appendix presents the results of the detailed runs conducted by MH at our behest of various drought scenarios, including five, ten and fifteen year low flow years to understand their impact on the key MH financial metrics.

The results of the five year droughts are followed by the extended low flow ten and fifteen year analyses.

The five-year drought Sale Scenarios are as follows:

Five Year Drought Sale Scenario 1

This scenario assumes a recurrence of the worst five year drought on record (1937 to 1941) commencing in 2013, coinciding with the construction stage of both Keeyask and Conawapa, and returning to average revenues for all 94 flow conditions in the periods preceding and following the drought period assuming expected, high and low export and natural gas prices as determined by the 2008 Price Forecast. All other assumptions are held constant with no adjustments to projected rate increases to consumers.

Exhibit J-1: Impact of Five Year Drought – Commencing in 2013

Sale Scenario Impact of Five Year Drought - Commencing in 2013 ($ millions)						
Forecast Fiscal Year	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**5-Year Total**
Water Flow Year	**1937**	**1938**	**1939**	**1940**	**1941**	**1937-1941**
LOW PRICES						
Revenue						
Extra Provincial Sales	(85.8)	(166.8)	(212.3)	(289.9)	(243.0)	**(997.8)**
Expenses (Recovery)						
Water Rentals	(10.5)	(17.9)	(28.3)	(37.1)	(29.6)	**(123.4)**
Fuel & Power Purchased	11.2	68.1	299.5	490.2	345.7	**1,214.7**
Reduction in Net Income (excluding financing costs)	**(86.5)**	**(217.0)**	**(483.5)**	**(743.0)**	**(559.1)**	**(2,089.1)**
Changes in Energy (GWh)						
Hydro Generation	(3,137.6)	(5,347.4)	(8,467.8)	(11,092.3)	(8,856.6)	**(36,901.7)**
Extra Provincial Sales	(2,466.8)	(3,663.0)	(4,021.1)	(4,575.3)	(4,154.6)	**(18,880.8)**
Fuel & Power Purchased	670.8	1,684.4	4,446.8	6,517.0	4,701.8	**18,020.8**
EXPECTED PRICES						
Revenue						
Extra Provincial Sales	(111.9)	(220.1)	(291.6)	(389.0)	(329.8)	**(1,342.4)**
Expenses (Recovery)						
Water Rentals	(10.5)	(17.9)	(28.3)	(37.1)	(29.6)	**(123.4)**
Fuel & Power Purchased	13.8	88.5	396.0	648.2	470.6	**1,617.1**
Reduction in Net Income (excluding financing costs)	**(115.2)**	**(290.7)**	**(659.3)**	**(1,000.1)**	**(770.8)**	**(2,836.1)**
Changes in Energy (GWh)						
Hydro Generation	(3,146.1)	(5,356.6)	(8,463.7)	(11,100.0)	(8,864.5)	**(36,930.9)**
Extra Provincial Sales	(2,486.4)	(3,684.4)	(4,104.2)	(4,587.1)	(4,168.6)	**(19,030.7)**
Fuel & Power Purchased	659.8	1,672.1	4,359.6	6,512.9	4,695.9	**17,900.3**
HIGH PRICES						
Revenue						
Extra Provincial Sales	(152.6)	(281.9)	(390.5)	(566.1)	(474.6)	**(1,865.7)**
Expenses (Recovery)						
Water Rentals	(10.6)	(17.9)	(28.4)	(37.1)	(29.8)	**(123.8)**
Fuel & Power Purchased	29.0	158.1	547.4	844.0	635.9	**2,214.4**
Reduction in Net Income (excluding financing costs)	**(171.0)**	**(422.1)**	**(909.5)**	**(1,373.0)**	**(1,080.7)**	**(3,956.3)**
Changes in Energy (GWh)						
Hydro Generation	(3,168.2)	(5,356.7)	(8,492.5)	(11,108.4)	(8,919.3)	**(37,045.1)**
Extra Provincial Sales	(2,451.7)	(3,463.1)	(3,987.3)	(4,660.9)	(4,190.2)	**(18,753.2)**
Fuel & Power Purchased	716.5	1,893.4	4,505.2	6,447.4	4,729.2	**18,291.7**

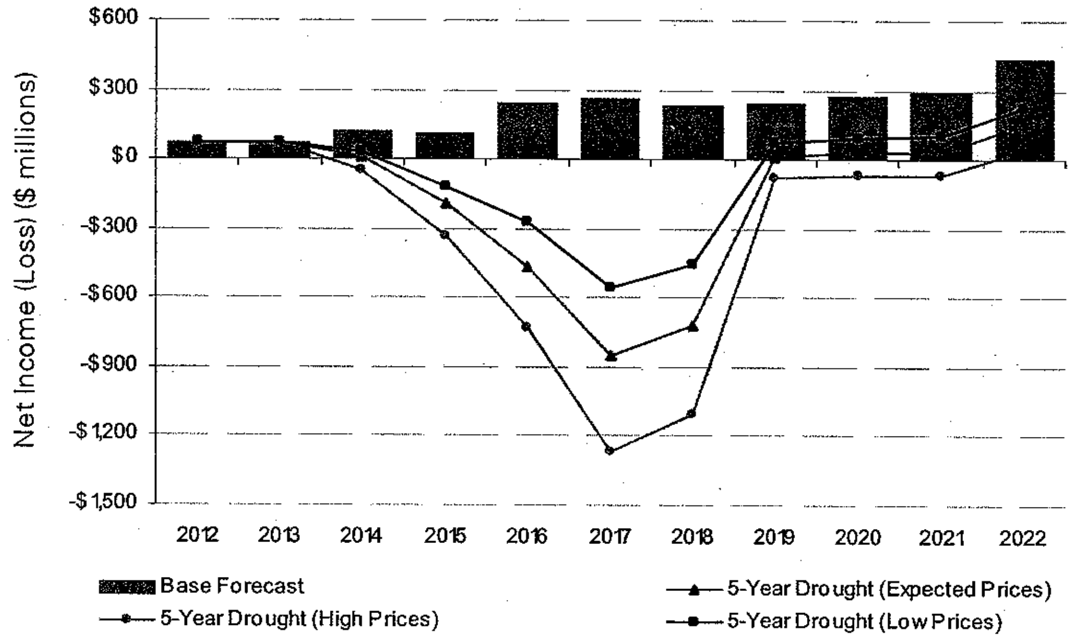
Source: derived from Manitoba Hydro data and model runs.

As illustrated in Exhibit J-1, the estimated financial impact of a five year drought beginning in 2013 would reduce Net Income otherwise available in the range of \$2.089 to \$3.956 billion, assuming low, expected and high export and natural gas prices.

The following graphs summarize the financial impact, including financing costs, of a five year drought commencing in 2013 on MH's key economic indicators, Net

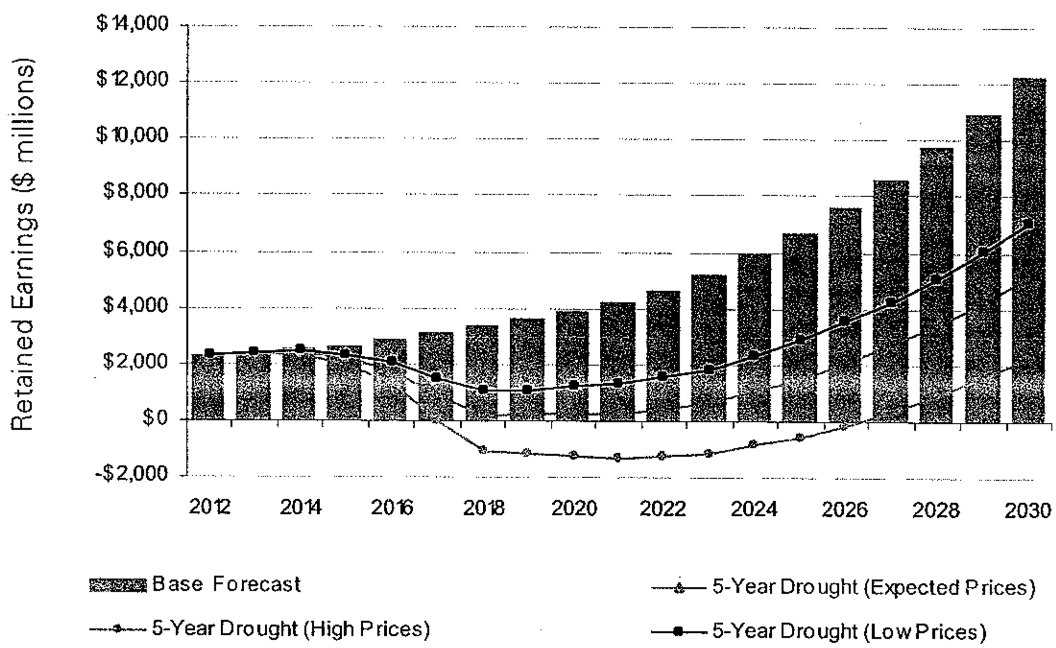
Income, Retained Earnings, and Debt Ratio compared to the Base Forecast contained in the 20 Year Financial Outlook.

Exhibit J-2: Sale Scenario Impact on Net Income of 5-Year Drought Commencing in 2013



Source: derived from Manitoba Hydro data and model runs.

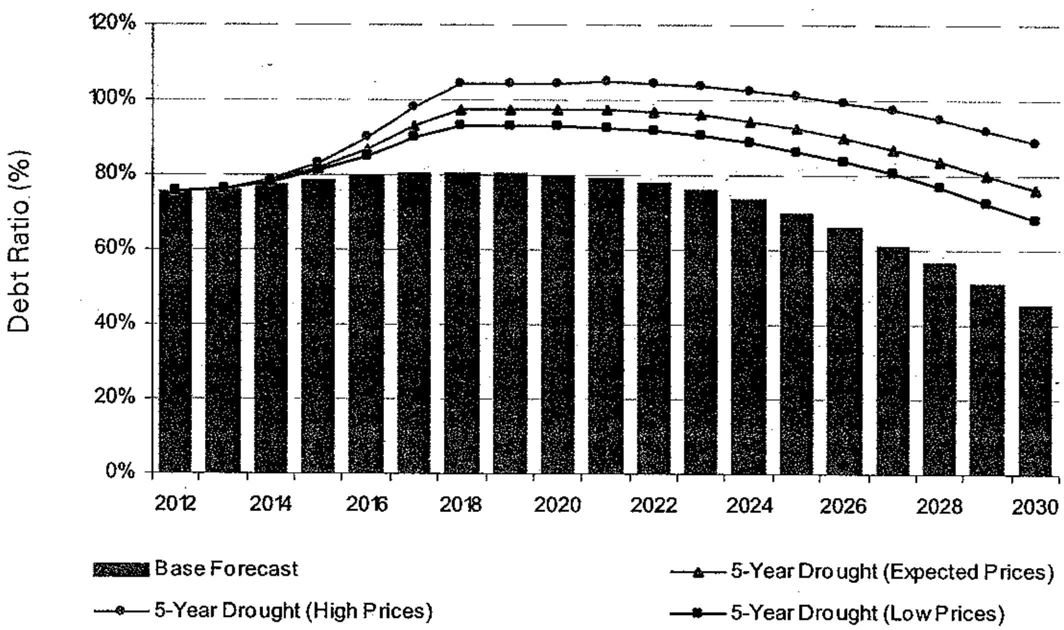
Exhibit J-3: Sale Scenario Impact on Retained Earnings of 5-Year Drought Commencing in 2013



Source: derived from Manitoba Hydro data and model runs.

MH's ability to withstand the financial impact of a five year drought will be dependent on the Retained Earnings available to MH during the drought periods. As indicated above, the estimated financial impact of a five year drought commencing in 2013 will result in nominal Retained Earnings assuming low and expected prices, and Deficits of up to $1.3 billion in the periods 2018 to 2026 assuming high prices.

Exhibit J-4: Sale Scenario Impact on Debt Ratio of 5-Year Drought Commencing in 2013



Source: derived from Manitoba Hydro data and model runs.

As indicated, assuming low and expected prices, the Debt Ratio will exceed the 75% target beginning in 2014 and will reach 93% and 97% in 2018 for low and expected prices respectively, returning to target levels by 2029/2030. Assuming high prices, the Debt Ratio will exceed the target beginning in 2014 and will reach 105% in 2021 and return to target levels in 2034.

Five Year Drought Sale Scenario 2

This scenario assumes a recurrence of the worst five year drought on record (1937 – 1941) commencing in 2019, coinciding with the in service date for Keeyask and construction stage of Conawapa, returning to average revenues for all 94 flow conditions in the periods preceding and following the drought period assuming expected, high and low prices. All other assumptions have been held constant and no adjustments were made to projected rate increases to consumers.

Exhibit J-5: Impact of Five Year Drought – Commencing in 2019

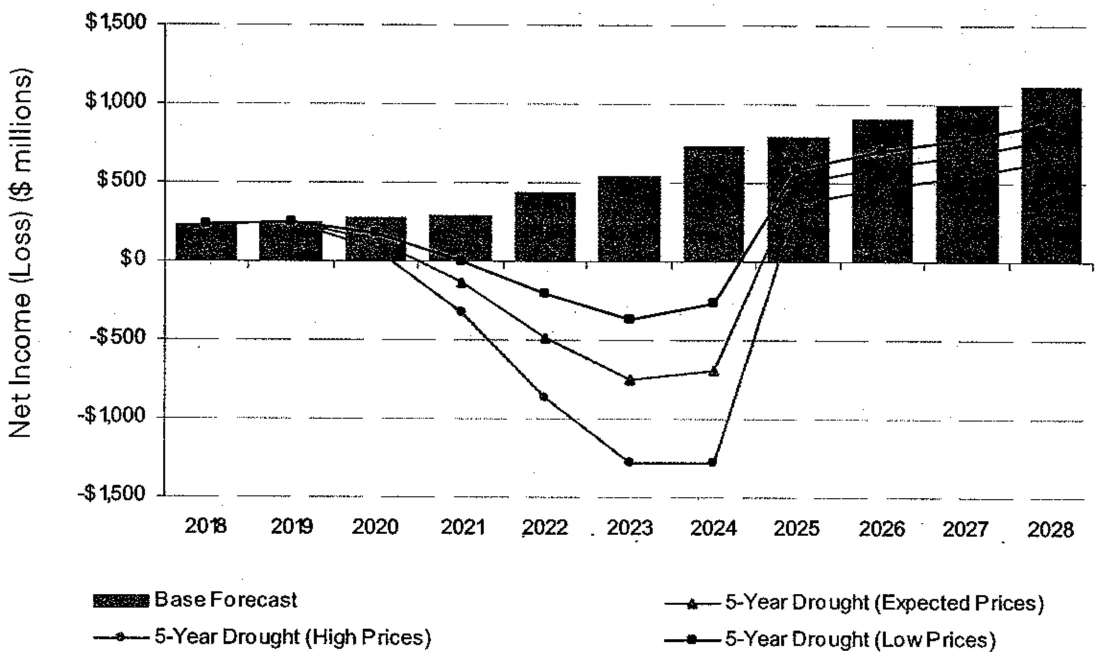
Sale Scenario Impact of Five Year Drought - Commencing in 2019 ($ millions)						
Forecast Fiscal Year Water Flow Year	2019/20 1937	2020/21 1938	2021/22 1939	2022/23 1940	2023/24 1941	5-Year Total 1937-1941
LOW PRICES						
Revenue						
Extra Provincial Sales	(75.9)	(161.1)	(207.7)	(194.1)	(225.2)	**(864.0)**
Expenses (Recovery)						
Water Rentals	(10.3)	(20.1)	(32.5)	(37.8)	(38.9)	**(139.6)**
Fuel & Power Purchased	32.0	142.0	429.9	653.4	645.1	**1,902.4**
Reduction in Net Income (excluding financing costs)	**(97.6)**	**(283.0)**	**(605.1)**	**(809.7)**	**(831.4)**	**(2,626.8)**
Changes in Energy (GWh)						
Hydro Generation	(3,075.0)	(6,002.1)	(9,720.1)	(11,302.2)	(11,654.7)	**(41,754.1)**
Extra Provincial Sales	(1,926.6)	(3,148.6)	(3,546.9)	(3,017.0)	(3,893.3)	**(15,532.4)**
Fuel & Power Purchased	1,148.5	2,853.5	6,172.9	8,285.3	7,761.3	**26,221.5**
EXPECTED PRICES						
Revenue						
Extra Provincial Sales	(109.3)	(198.3)	(299.7)	(285.8)	(328.9)	**(1,222.0)**
Expenses (Recovery)						
Water Rentals	(10.3)	(20.1)	(32.5)	(37.8)	(39.1)	**(139.8)**
Fuel & Power Purchased	40.3	232.6	590.9	904.7	901.6	**2,670.1**
Reduction in Net Income (excluding financing costs)	**(139.3)**	**(410.8)**	**(858.1)**	**(1,152.7)**	**(1,191.4)**	**(3,752.3)**
Changes in Energy (GWh)						
Hydro Generation	(3,091.2)	(6,015.2)	(9,721.8)	(11,314.7)	(11,694.9)	**(41,837.8)**
Extra Provincial Sales	(1,982.0)	(2,957.9)	(3,598.6)	(3,090.6)	(3,959.1)	**(15,588.2)**
Fuel & Power Purchased	1,109.0	3,057.2	6,123.3	8,224.0	7,735.7	**26,249.2**
HIGH PRICES						
Revenue						
Extra Provincial Sales	(136.1)	(293.3)	(471.9)	(465.1)	(502.5)	**(1,868.9)**
Expenses (Recovery)						
Water Rentals	(10.3)	(20.1)	(32.6)	(37.9)	(39.1)	**(140.0)**
Fuel & Power Purchased	75.3	319.7	771.9	1,202.1	1,218.2	**3,587.2**
Reduction in Net Income (excluding financing costs)	**(201.1)**	**(592.9)**	**(1,211.2)**	**(1,629.3)**	**(1,681.6)**	**(5,316.1)**
Changes in Energy (GWh)						
Hydro Generation	(3,097.3)	(6,007.7)	(9,742.8)	(11,336.1)	(11,698.8)	**(41,882.7)**
Extra Provincial Sales	(1,868.2)	(3,019.6)	(3,813.4)	(3,370.1)	(4,120.3)	**(16,191.6)**
Fuel & Power Purchased	1,229.0	2,988.4	5,929.5	7,966.1	7,578.4	**25,691.4**

Source: derived from Manitoba Hydro data and model runs.

As illustrated in Exhibit J-5, the estimated financial impact of a five year drought beginning in 2019 would reduce Net Income otherwise available in the range of $2.627 to $5.316 billion, assuming low, expected and high export and natural gas prices.

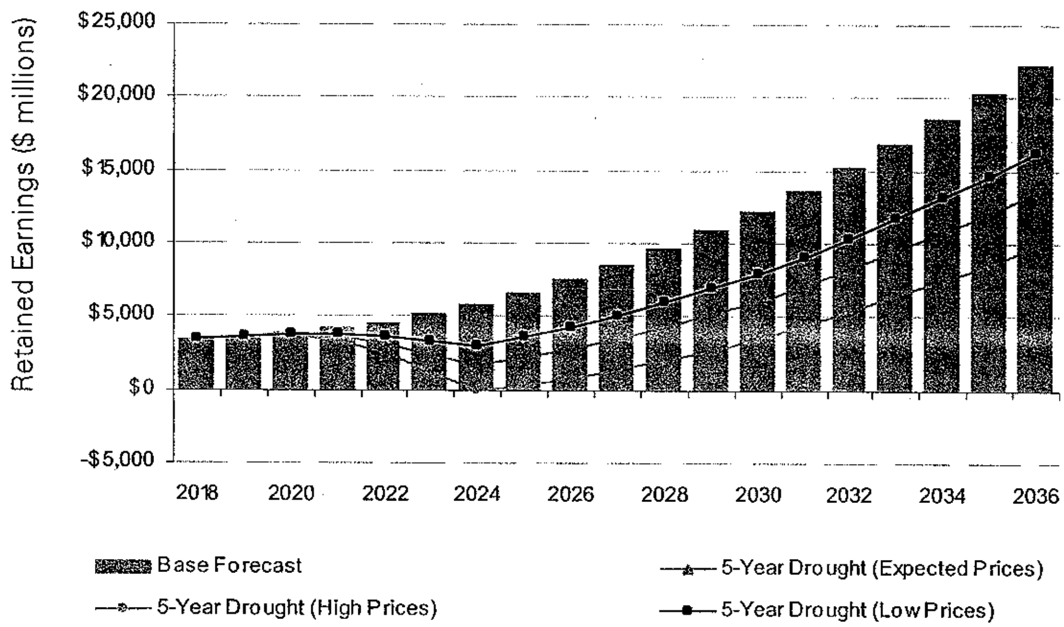
The following graphs summarize the financial impact including financing costs of a five year drought commencing in 2019 on the key economic indicators, Net Income, Retained Earnings, and the Debt Ratio compared to the Base Forecast contained in the 20 Year Financial Outlook.

Exhibit J-6: Sale Scenario Impact on Net Income of 5-Year Drought Commencing in 2019



Source: derived from Manitoba Hydro data and model runs.

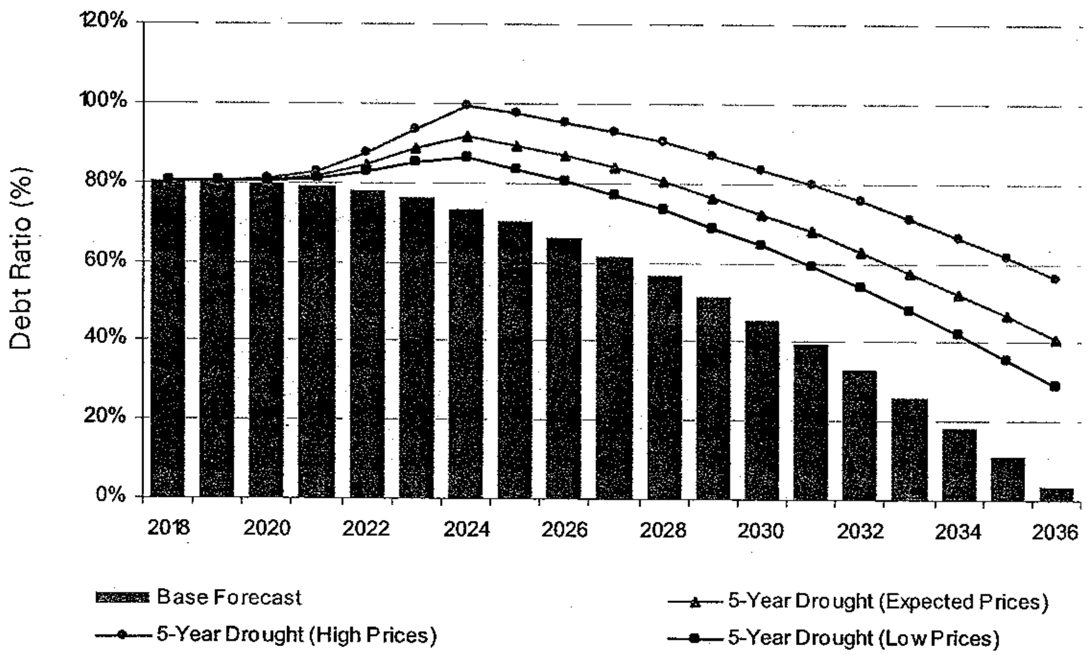
Exhibit J-7: Sale Scenario Impact on Retained Earnings of 5-Year Drought Commencing in 2019



Source: derived from Manitoba Hydro data and model runs.

As indicated, the estimated financial impact of a five year drought commencing in 2019 will result in sufficient Retained Earnings to withstand the drought assuming both low and expected price, and a nominal Deficit in 2024 and Retained Earnings immediately thereafter assuming high prices.

Exhibit J-8: Sale Scenario Impact on Debt Ratio of 5-Year Drought Commencing in 2019



Source: derived from Manitoba Hydro data and model runs.

The Debt Ratio will reach highs of 86%, 91% and 99% in 2024 assuming low, expected and high prices respectively.

Five Year Drought Sale Scenario 3

This scenario assumes a recurrence of the worst five year drought on record (1937 – 1941) commencing in 2025, coinciding with the in service date of Conawapa, returning to average revenues for all 94 flow conditions in the periods preceding and following the drought period assuming low, expected and high prices. All other assumptions have been held constant and no adjustments were made to projected rate increases to consumers.

Exhibit J-9: Impact of Five Year Drought – Commencing in 2025

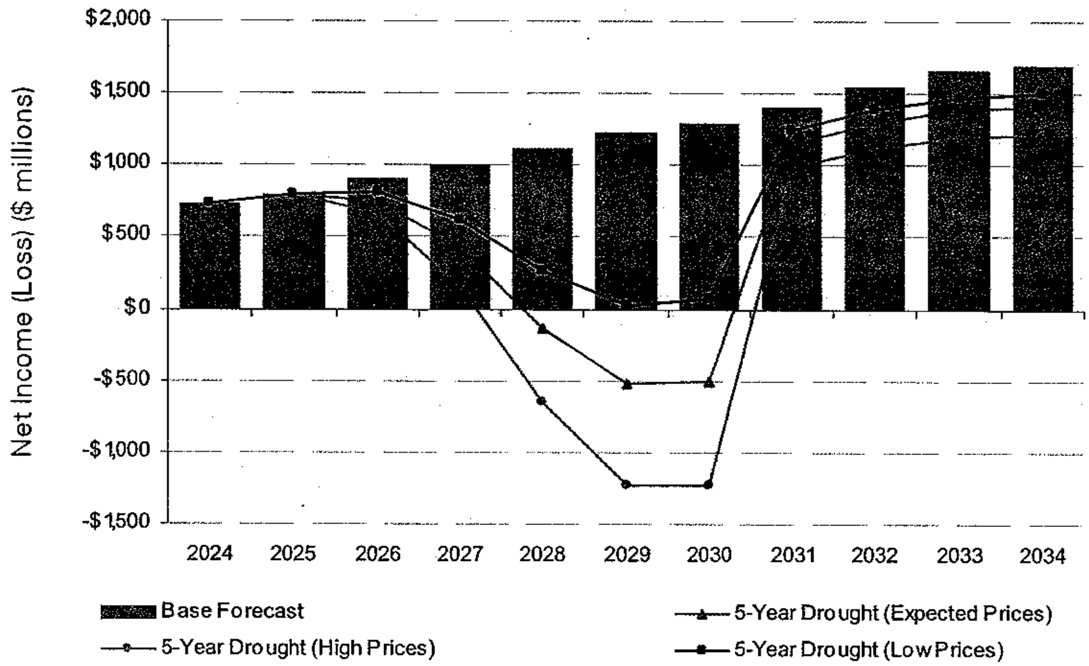
Sale Sceanrio Impact of Five Year Drought - Commencing in 2025 ($ millions)						
Forecast Fiscal Year	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**5-Year Total**
Water Flow Year	**1937**	**1938**	**1939**	**1940**	**1941**	**1937-1941**
LOW PRICES						
Revenue						
Extra Provincial Sales	(114.8)	(240.7)	(379.6)	(469.6)	(487.7)	**(1,692.4)**
Expenses (Recovery)						
Water Rentals	(12.6)	(24.0)	(38.4)	(45.3)	(43.5)	**(163.8)**
Fuel & Power Purchased	(0.4)	154.6	473.4	694.5	651.6	**1,973.7**
Reduction in Net Income (excluding financing costs)	**(101.8)**	**(371.3)**	**(814.6)**	**(1,118.8)**	**(1,095.8)**	**(3,502.3)**
Changes in Energy (GWh)						
Hydro Generation	(3,760.3)	(7,180.0)	(11,489.2)	(13,561.6)	(13,007.5)	**(48,998.6)**
Extra Provincial Sales	(3,035.9)	(4,473.3)	(5,655.3)	(6,141.1)	(6,204.5)	**(25,510.1)**
Fuel & Power Purchased	724.4	2,706.7	5,833.8	7,420.6	6,803.0	**23,488.5**
EXPECTED PRICES						
Revenue						
Extra Provincial Sales	(165.9)	(360.2)	(508.2)	(711.3)	(736.5)	**(2,482.1)**
Expenses (Recovery)						
Water Rentals	(12.5)	(24.0)	(38.5)	(45.4)	(43.5)	**(163.9)**
Fuel & Power Purchased	4.4	224.3	731.3	964.1	913.3	**2,837.4**
Reduction in Net Income (excluding financing costs)	**(157.8)**	**(560.5)**	**(1,201.0)**	**(1,630.0)**	**(1,606.3)**	**(5,155.6)**
Changes in Energy (GWh)						
Hydro Generation	(3,727.4)	(7,181.2)	(11,517.2)	(13,576.2)	(13,025.5)	**(49,027.5)**
Extra Provincial Sales	(3,024.2)	(4,519.3)	(5,404.1)	(6,198.2)	(6,230.8)	**(25,376.6)**
Fuel & Power Purchased	703.2	2,661.9	6,113.2	7,378.0	6,794.7	**23,651.0**
HIGH PRICES						
Revenue						
Extra Provincial Sales	(238.4)	(479.1)	(694.8)	(1,048.1)	(1,047.8)	**(3,508.2)**
Expenses (Recovery)						
Water Rentals	(12.5)	(24.0)	(38.6)	(45.4)	(43.0)	**(163.5)**
Fuel & Power Purchased	14.1	366.0	1,028.8	1,281.1	1,204.3	**3,894.3**
Reduction in Net Income (excluding financing costs)	**(240.0)**	**(821.1)**	**(1,685.0)**	**(2,283.8)**	**(2,209.1)**	**(7,239.0)**
Changes in Energy (GWh)						
Hydro Generation	(3,741.5)	(7,183.8)	(11,540.0)	(13,594.1)	(12,879.3)	**(48,938.7)**
Extra Provincial Sales	(3,030.7)	(4,348.1)	(5,242.9)	(6,280.8)	(6,205.9)	**(25,108.4)**
Fuel & Power Purchased	711.0	2,835.8	6,297.0	7,313.3	6,673.6	**23,830.7**

Source: derived from Manitoba Hydro data and model runs.

As illustrated in Exhibit J-9, the estimated financial impact of a five year drought beginning in 2025 would reduce net income otherwise available in the range of $3.502 to $7.239 billion, assuming low, expected, and high export and natural gas prices.

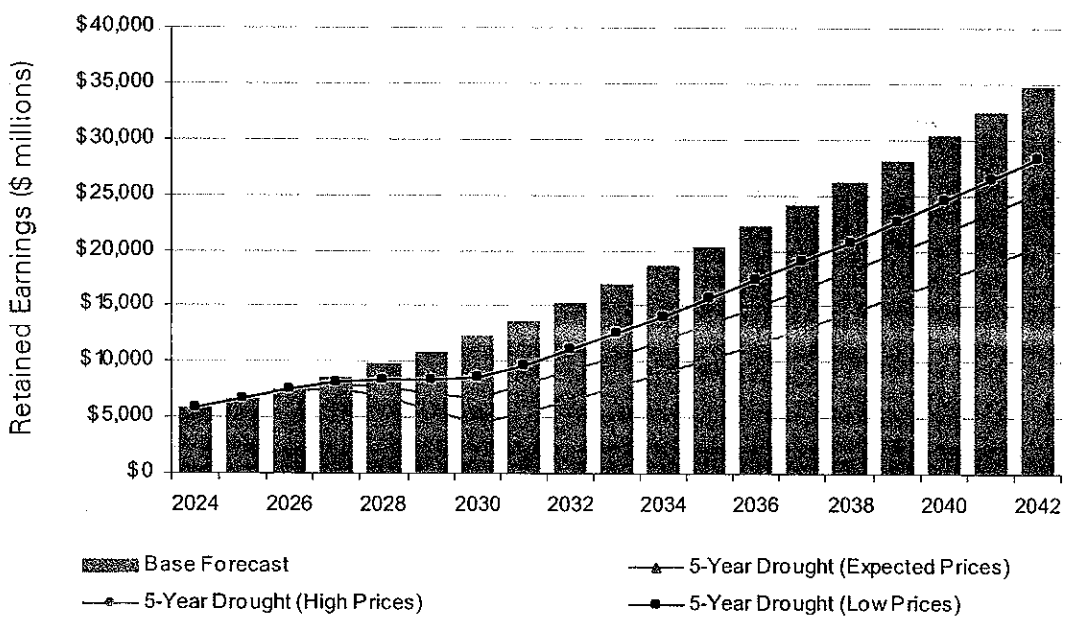
The following graphs summarize the financial impact including financing costs of a five year drought commencing in 2025 on the key economic indicators, Net Income, Retained Earnings, and the Debt Ratio compared to the Base Forecast contained in the 20 Year Financial Outlook.

Exhibit J-10: Sale Scenario Impact on Net Income of 5-Year Drought Commencing in 2025



Source: derived from Manitoba Hydro data and model runs.

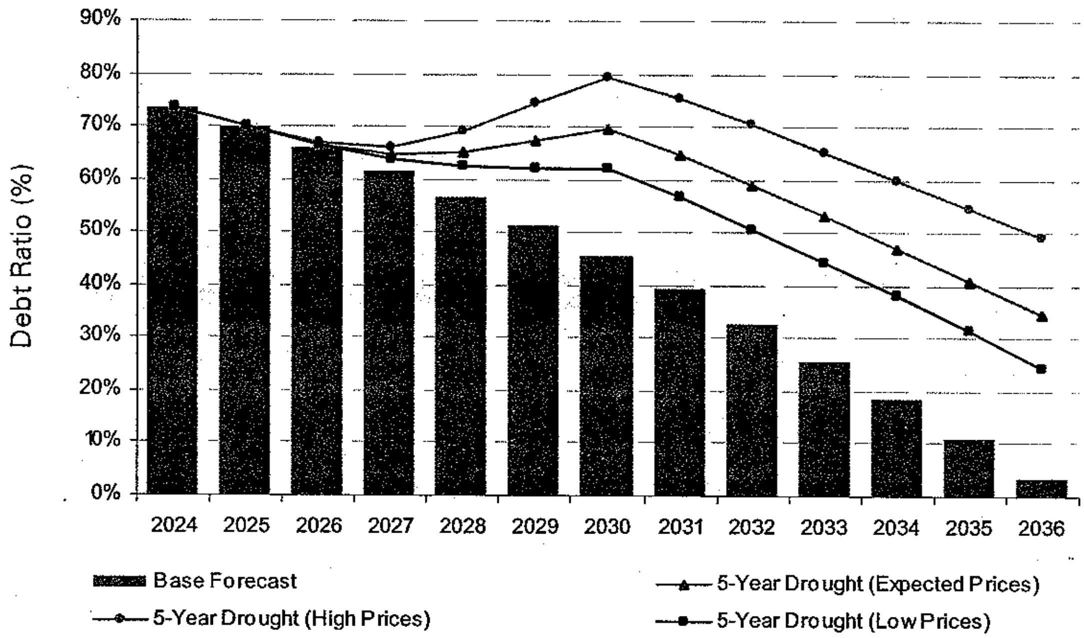
Exhibit J-11: Sale Scenario Impact on Retained Earnings of 5-Year Drought Commencing in 2025



Source: derived from Manitoba Hydro data and model runs.

As indicated, assuming low, expected or high prices, there should be sufficient Retained Earnings to withstand the estimated financial impact of a five year drought commencing in 2025.

Exhibit J-12: Sale Scenario Impact on Debt Ratio of 5-Year Drought Commencing in 2025



Source: derived from Manitoba Hydro data and model runs.

The Debt Ratio and will be below the target debt ratio of 75% in all years for both low and expected prices, and will reach 80% in 2030 assuming high prices.

Alternative Development Plan Sequence Analysis

In this section we consider the impact of drought risk related to the new generation development sequence and the related long-term export contracts.

We asked MH to consider the impact of five year droughts commencing at various times in a situation where new generation capacity is only added as required to meet Manitoba load growth. The development sequence required to meet Manitoba load growth includes Conawapa in 2021/22 (advanced one year from 2022/23 in the IFF09 and 20 Year Financial Outlook) and a combined cycle combustion turbine in 2033/34. This sequence excludes the export sales related to the WPS and MP contracts, the construction of Keeyask, and the planned US transmission interconnection (herein defined as the "No Sale Scenario").

A comparison of the financial impacts of drought conditions under a Sale Scenario and a No Sale Scenario will allow us to isolate the financial risks associated with the associated development investments of additional generation (Keeysak), new US transmission interconnection, and the related long-term export contracts with WPS and MP. The quantification of drought risk is represented by the change in the financial position of MH in comparison to the Alterative No Sale financial forecast prepared by MH ("Alternative Base").

A summary of the five year drought under a No Sale Scenario at various commencement periods is provided below.

Five Year Drought No Sale Scenario 1

This No Sale Scenario assumes a recurrence of the worst five year drought on record (1937 – 1941) commencing in 2013, returning to average revenues for all 94 flow conditions in the periods preceding and following the drought period assuming expected, high and low prices, with all other assumptions held constant and no adjustments to projected rate increases to consumers.

Exhibit J-13: Impact of Five Year Drought – Commencing in 2013

No Sale Scenario Impact of Five Year Drought - Commencing in 2013 ($ millions)						
Forecast Fiscal Year	2013/14	2014/15	2015/16	2016/17	2017/18	5-Year Total
Water Flow Year	1937	1938	1939	1940	1941	1937-1941
LOW PRICES						
Revenue						
Extra Provincial Sales	(85.7)	(166.8)	(211.7)	(290.7)	(242.9)	**(997.8)**
Expenses (Recovery)						
Water Rentals	(10.5)	(17.9)	(28.3)	(37.3)	(29.7)	**(123.7)**
Fuel & Power Purchased	11.0	67.4	299.6	493.5	350.9	**1,222.4**
Reduction in Net Income (excluding financing costs)	**(86.2)**	**(216.3)**	**(483.0)**	**(746.9)**	**(564.1)**	**(2,096.5)**
Changes in Energy (GWh)						
Hydro Generation	(3,134.1)	(5,344.1)	(8,467.7)	(11,170.8)	(8,886.8)	**(37,003.5)**
Extra Provincial Sales	(2,467.5)	(3,666.9)	(4,017.9)	(4,603.6)	(4,145.5)	**(18,901.4)**
Fuel & Power Purchased	666.7	1,677.1	4,449.8	6,567.2	4,741.3	**18,102.1**
EXPECTED PRICES						
Revenue						
Extra Provincial Sales	(112.0)	(220.1)	(290.9)	(390.2)	(329.6)	**(1,342.8)**
Expenses (Recovery)						
Water Rentals	(10.5)	(17.9)	(28.3)	(37.3)	(29.7)	**(123.7)**
Fuel & Power Purchased	13.4	87.6	396.2	652.6	477.2	**1,627.0**
Reduction in Net Income (excluding financing costs)	**(114.9)**	**(289.8)**	**(658.8)**	**(1,005.5)**	**(777.1)**	**(2,846.1)**
Changes in Energy (GWh)						
Hydro Generation	(3,141.6)	(5,353.1)	(8,464.4)	(11,179.1)	(8,891.9)	**(37,030.1)**
Extra Provincial Sales	(2,488.1)	(3,689.0)	(4,101.7)	(4,616.7)	(4,159.5)	**(19,055.0)**
Fuel & Power Purchased	653.5	1,664.1	4,362.7	6,562.4	4,732.4	**17,975.1**
HIGH PRICES						
Revenue						
Extra Provincial Sales	(152.5)	(282.3)	(389.6)	(567.7)	(462.6)	**(1,854.7)**
Expenses (Recovery)						
Water Rentals	(10.6)	(17.9)	(28.4)	(37.4)	(29.9)	**(124.2)**
Fuel & Power Purchased	28.6	156.4	547.6	850.3	650.3	**2,233.2**
Reduction in Net Income (excluding financing costs)	**(170.5)**	**(420.8)**	**(908.8)**	**(1,380.6)**	**(1,083.0)**	**(3,963.7)**
Changes in Energy (GWh)						
Hydro Generation	(3,164.2)	(5,352.6)	(8,491.7)	(11,186.0)	(8,939.0)	**(37,133.5)**
Extra Provincial Sales	(2,452.4)	(3,471.3)	(3,984.3)	(4,688.2)	(4,128.2)	**(18,724.4)**
Fuel & Power Purchased	711.8	1,881.5	4,507.3	6,497.7	4,810.9	**18,409.2**

Source: derived from Manitoba Hydro data and model runs.

As illustrated in Exhibit J-13, the impact of a five year drought beginning in 2013 would reduce Net Income in the range of $2.096 to $3.964 billion, assuming low, expected and high export and natural gas prices.

The following graphs summarize the financial impact including financing costs of a five year drought commencing in 2013 assuming a No Sale Scenario, and the key economic indicators Net Income, Retained Earnings, and the Debt Ratio compared to the Alternative Base financial forecast.

Exhibit J-14: No Sale Scenario Impact on Net Income of 5-Year Drought Commencing in 2013

mh

[redacted]

Alternative Base
5-Year Drought (High Prices)
5-Year Drought (Expected Prices)
5-Year Drought (Low Prices)

Source: derived from Manitoba Hydro data and model runs.

Exhibit J-15: No Sale Scenario Impact on Retained Earnings of 5-Year Drought Commencing in 2013

mh

[redacted]

Alternative Base
5-Year Drought (High Prices)
5-Year Drought (Expected Prices)
5-Year Drought (Low Prices)

Source: derived from Manitoba Hydro data and model runs.

As indicated, assuming low price, there will be sufficient Retained Earnings to withstand the drought. For expected prices, the deficit will reach $.145 billion in 2020 and for high prices, the deficit will reach up to $1.67 billion in 2021.

Exhibit J-16: No Sale Scenario Impact on Debt Ratio of 5-Year Drought Commencing in 2013

4., 7.

[redacted]

Alternative Base
5-Year Drought (High Prices)
5-Year Drought (Expected Prices)
5-Year Drought (Low Prices)

Source: derived from Manitoba Hydro data and model runs.

The Debt Ratio will reach 94% in 2019 assuming low prices, and 99% and 108% in 2021 assuming expected and high prices respectively.

Five Year Drought No Sale Scenario 2

This No Sale Scenario assumes a recurrence of the worst five year drought on record (1937 – 1941) commencing in 2019, returning to average revenues for all 94 flow conditions in the periods preceding and following the drought period assuming expected, high and low prices. All other assumptions have been held constant and no adjustments were made to projected rate increases to consumers.

Exhibit J-17: Impact of Five Year Drought – Commencing in 2019

Forecast Fiscal Year	2019/20	2020/21	2021/22	2022/23	2023/24	5-Year Total
Water Flow Year	1937	1938	1939	1940	1941	1937-1941
LOW PRICES						
Revenue						
Extra Provincial Sales	(117.1)	(183.6)	(219.1)	(289.3)	(270.6)	**(1,079.7)**
Expenses (Recovery)						
Water Rentals	(10.7)	(17.6)	(28.1)	(38.6)	(36.4)	**(131.4)**
Fuel & Power Purchased	3.6	118.2	396.6	584.2	530.8	**1,633.4**
Reduction in Net Income (excluding financing costs)	**(110.0)**	**(284.2)**	**(587.6)**	**(834.9)**	**(765.0)**	**(2,581.7)**
Changes in Energy (GWh)						
Hydro Generation	(3,215.1)	(5,278.9)	(8,405.8)	(11,559.6)	(10,894.1)	**(39,353.5)**
Extra Provincial Sales	(2,621.5)	(3,408.4)	(3,533.3)	(4,954.6)	(4,905.1)	**(19,422.9)**
Fuel & Power Purchased	593.6	1,870.7	4,872.4	6,605.0	5,989.1	**19,930.8**
EXPECTED PRICES						
Revenue						
Extra Provincial Sales	(164.4)	(259.8)	(311.1)	(414.3)	(390.9)	**(1,540.5)**
Expenses (Recovery)						
Water Rentals	(10.8)	(17.7)	(28.1)	(38.7)	(36.4)	**(131.7)**
Fuel & Power Purchased	2.8	161.0	545.2	807.0	731.7	**2,247.7**
Reduction in Net Income (excluding financing costs)	**(156.4)**	**(403.1)**	**(828.2)**	**(1,182.6)**	**(1,086.2)**	**(3,656.5)**
Changes in Energy (GWh)						
Hydro Generation	(3,217.8)	(5,294.8)	(8,410.6)	(11,573.8)	(10,905.4)	**(39,402.4)**
Extra Provincial Sales	(2,647.9)	(3,447.3)	(3,553.6)	(4,991.6)	(4,940.8)	**(19,581.2)**
Fuel & Power Purchased	569.9	1,847.6	4,856.9	6,582.1	5,964.8	**19,821.3**
HIGH PRICES						
Revenue						
Extra Provincial Sales	(247.7)	(316.2)	(445.3)	(603.4)	(569.7)	**(2,182.3)**
Expenses (Recovery)						
Water Rentals	(10.7)	(17.8)	(28.3)	(38.7)	(36.5)	**(132.0)**
Fuel & Power Purchased	0.1	278.7	748.0	1,086.1	975.0	**3,087.9**
Reduction in Net Income (excluding financing costs)	**(237.1)**	**(577.1)**	**(1,165.0)**	**(1,650.8)**	**(1,508.2)**	**(5,138.2)**
Changes in Energy (GWh)						
Hydro Generation	(3,209.8)	(5,315.9)	(8,484.7)	(11,581.0)	(10,917.8)	**(39,509.2)**
Extra Provincial Sales	(2,721.5)	(3,134.6)	(3,560.2)	(5,029.2)	(4,982.2)	**(19,427.7)**
Fuel & Power Purchased	488.4	2,181.3	4,924.6	6,551.8	5,935.6	**20,081.7**

Source: derived from Manitoba Hydro data and model runs.

As illustrated above, the impact of a five year drought beginning in 2019 would reduce Net Income in the range of $2.582 to $5.138 billion, assuming low, expected and high export and natural gas prices.

The following graphs summarize the financial impact including financing costs of a five year drought commencing in 2019 assuming a No Sale Scenario and the key economic indicators Net Income, Retained Earnings, and the Debt Ratio compared to the Alternative Base financial forecast.

Exhibit J-18: No Sale Scenario Impact on Net Income of 5-Year Drought Commencing in 2019

4.7. MH

Net Income (Loss) ($ millions)

[redacted]

Alternative Base
5-Year Drought (High Prices)
5-Year Drought (Expected Prices)
5-Year Drought (Low Prices)

Source: derived from Manitoba Hydro data and model runs.

Exhibit J-19: No Sale Scenario Impact on Retained Earnings of 5-Year Drought Commencing in 2019

4.7. MH

Retained Earnings ($ millions)

[redacted]

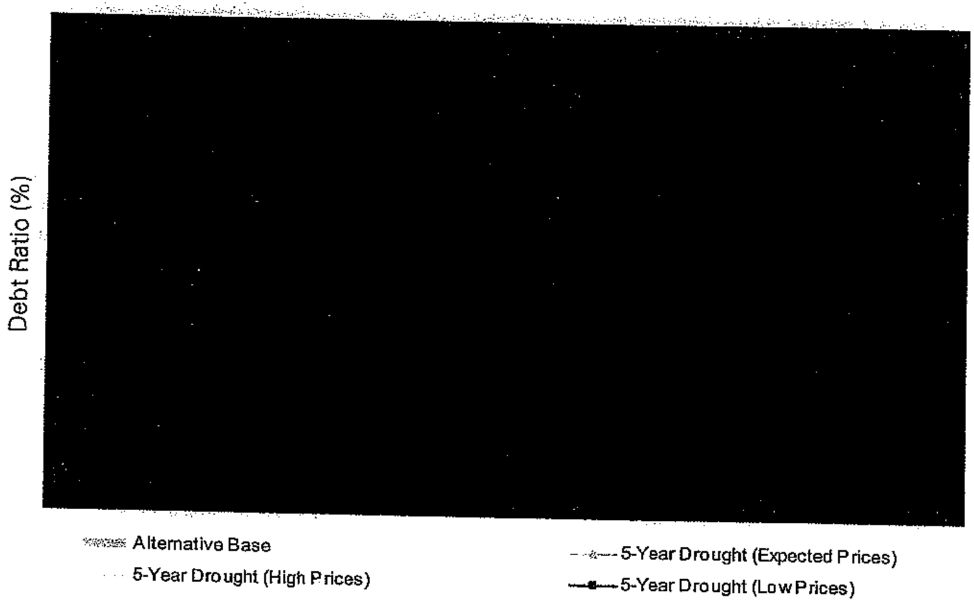
Alternative Base
5-Year Drought (High Prices)
5-Year Drought (Expected Prices)
5-Year Drought (Low Prices)

Source: derived from Manitoba Hydro data and model runs.

As illustrated, there should be sufficient Retained Earnings to withstand the drought assuming low and expected prices, and a Deficit reaching $.292 billion in 2024 assuming high prices.

Exhibit J-20: No Sale Scenario Impact on Debt Ratio of 5-Year Drought Commencing in 2019

MH



Source: derived from Manitoba Hydro data and model runs.

As indicated, assuming expected prices, the Debt Ratio will exceed the 75% target and reach 84%, 91% and 100% in 2024 assuming low, expected and high prices.

Five Year Drought No Sale Scenario 3

This No Sale Scenario assumes a recurrence of the worst five year drought on record (1937 – 1941) commencing in 2025, returning to average revenues for all 94 flow conditions in the periods preceding and following the drought period assuming both expected, high and low prices. All other assumptions have been held constant and no adjustments were made to projected rate increases to consumers.

Exhibit J-21: Impact of Five Year Drought – Commencing in 2025

Forecast Fiscal Year	2025/26	2026/27	2027/28	2028/29	2029/30	5-Year Total
Water Flow Year	1937	1938	1939	1940	1941	1937-1941
LOW PRICES						
Revenue						
Extra Provincial Sales	(96.6)	(275.3)	(487.2)	(591.0)	(543.9)	**(1,994.0)**
Expenses (Recovery)						
Water Rentals	(11.1)	(20.7)	(34.3)	(41.5)	(38.0)	**(145.6)**
Fuel & Power Purchased	(6.2)	45.7	280.6	500.9	428.7	**1,249.7**
Reduction in Net Income (excluding financing costs)	**(79.3)**	**(300.3)**	**(733.5)**	**(1,050.4)**	**(934.6)**	**(3,098.1)**
Changes in Energy (GWh)						
Hydro Generation	(3,314.8)	(6,198.2)	(10,264.7)	(12,429.8)	(11,382.0)	**(43,589.5)**
Extra Provincial Sales	(2,917.6)	(5,072.9)	(7,076.8)	(7,679.0)	(7,315.1)	**(30,061.4)**
Fuel & Power Purchased	397.1	1,125.1	3,187.8	4,750.9	4,066.9	**13,527.8**
EXPECTED PRICES						
Revenue						
Extra Provincial Sales	(145.6)	(411.7)	(631.9)	(894.0)	(760.4)	**(2,843.6)**
Expenses (Recovery)						
Water Rentals	(11.1)	(20.7)	(34.3)	(41.6)	(38.1)	**(145.8)**
Fuel & Power Purchased	(10.8)	65.1	472.4	673.4	640.4	**1,840.5**
Reduction in Net Income (excluding financing costs)	**(123.7)**	**(456.1)**	**(1,070.0)**	**(1,525.8)**	**(1,362.7)**	**(4,538.3)**
Changes in Energy (GWh)						
Hydro Generation	(3,321.8)	(6,208.2)	(10,280.5)	(12,438.3)	(11,393.0)	**(43,641.8)**
Extra Provincial Sales	(2,964.5)	(5,128.3)	(6,610.5)	(7,740.6)	(7,046.8)	**(29,490.7)**
Fuel & Power Purchased	357.3	1,079.8	3,670.0	4,697.7	4,346.1	**14,150.9**
HIGH PRICES						
Revenue						
Extra Provincial Sales	(219.0)	(529.4)	(822.0)	(1,300.2)	(1,042.2)	**(3,912.8)**
Expenses (Recovery)						
Water Rentals	(11.1)	(20.9)	(34.3)	(41.6)	(38.1)	**(146.0)**
Fuel & Power Purchased	(16.3)	164.9	703.0	869.7	884.0	**2,605.3**
Reduction in Net Income (excluding financing costs)	**(191.6)**	**(673.4)**	**(1,490.7)**	**(2,128.3)**	**(1,888.1)**	**(6,372.1)**
Changes in Energy (GWh)						
Hydro Generation	(3,323.7)	(6,242.3)	(10,271.8)	(12,436.9)	(11,398.1)	**(43,672.8)**
Extra Provincial Sales	(3,012.1)	(4,834.2)	(6,230.9)	(7,759.0)	(6,822.7)	**(28,658.9)**
Fuel & Power Purchased	311.5	1,408.1	4,040.7	4,677.9	4,575.3	**15,013.5**

Source: derived from Manitoba Hydro data and model runs.

As illustrated above, the impact of a five year drought beginning in 2025 would reduce Net Income in the range of $3.098 to $6.372 billion, assuming low, expected and high export and natural gas prices.

The following graphs summarize the No Sale Scenario financial impact including financing costs of a five year drought commencing in 2025 and the key economic

Exhibit J-21: Impact of Five Year Drought – Commencing in 2025

No Sale Scenario Impact of Five Year Drought - Commencing in 2025 ($ millions)						
Forecast Fiscal Year	**2025/26**	**2026/27**	**2027/28**	**2028/29**	**2029/30**	**5-Year Total**
Water Flow Year	**1937**	**1938**	**1939**	**1940**	**1941**	**1937-1941**
LOW PRICES						
Revenue						
Extra Provincial Sales	(96.6)	(275.3)	(487.2)	(591.0)	(543.9)	**(1,994.0)**
Expenses (Recovery)						
Water Rentals	(11.1)	(20.7)	(34.3)	(41.5)	(38.0)	**(145.6)**
Fuel & Power Purchased	(6.2)	45.7	280.6	500.9	428.7	**1,249.7**
Reduction in Net Income (excluding financing costs)	**(79.3)**	**(300.3)**	**(733.5)**	**(1,050.4)**	**(934.6)**	**(3,098.1)**
Changes in Energy (GWh)						
Hydro Generation	(3,314.8)	(6,198.2)	(10,264.7)	(12,429.8)	(11,382.0)	**(43,589.5)**
Extra Provincial Sales	(2,917.6)	(5,072.9)	(7,076.8)	(7,679.0)	(7,315.1)	**(30,061.4)**
Fuel & Power Purchased	397.1	1,125.1	3,187.8	4,750.9	4,066.9	**13,527.8**
EXPECTED PRICES						
Revenue						
Extra Provincial Sales	(145.6)	(411.7)	(631.9)	(894.0)	(760.4)	**(2,843.6)**
Expenses (Recovery)						
Water Rentals	(11.1)	(20.7)	(34.3)	(41.6)	(38.1)	**(145.8)**
Fuel & Power Purchased	(10.8)	65.1	472.4	673.4	640.4	**1,840.5**
Reduction in Net Income (excluding financing costs)	**(123.7)**	**(456.1)**	**(1,070.0)**	**(1,525.8)**	**(1,362.7)**	**(4,538.3)**
Changes in Energy (GWh)						
Hydro Generation	(3,321.8)	(6,208.2)	(10,280.5)	(12,438.3)	(11,393.0)	**(43,641.8)**
Extra Provincial Sales	(2,964.5)	(5,128.3)	(6,610.5)	(7,740.6)	(7,046.8)	**(29,490.7)**
Fuel & Power Purchased	357.3	1,079.8	3,670.0	4,697.7	4,346.1	**14,150.9**
HIGH PRICES						
Revenue						
Extra Provincial Sales	(219.0)	(529.4)	(822.0)	(1,300.2)	(1,042.2)	**(3,912.8)**
Expenses (Recovery)						
Water Rentals	(11.1)	(20.9)	(34.3)	(41.6)	(38.1)	**(146.0)**
Fuel & Power Purchased	(16.3)	164.9	703.0	869.7	884.0	**2,605.3**
Reduction in Net Income (excluding financing costs)	**(191.6)**	**(673.4)**	**(1,490.7)**	**(2,128.3)**	**(1,888.1)**	**(6,372.1)**
Changes in Energy (GWh)						
Hydro Generation	(3,323.7)	(6,242.3)	(10,271.8)	(12,436.9)	(11,398.1)	**(43,672.8)**
Extra Provincial Sales	(3,012.1)	(4,834.2)	(6,230.9)	(7,759.0)	(6,822.7)	**(28,658.9)**
Fuel & Power Purchased	311.5	1,408.1	4,040.7	4,677.9	4,575.3	**15,013.5**

Source: derived from Manitoba Hydro data and model runs.

As illustrated above, the impact of a five year drought beginning in 2025 would reduce Net Income in the range of $3.098 to $6.372 billion, assuming low, expected and high export and natural gas prices.

The following graphs summarize the No Sale Scenario financial impact including financing costs of a five year drought commencing in 2025 and the key economic indicators Net Income, Retained Earnings, and the Debt Ratio compared to the Alternative Base financial forecast.

Exhibit J-22: No Sale Scenario Impact on Net Income of 5-Year Drought Commencing in 2025

Net Income (Loss) ($ millions)

[redacted]

MH

Alternative Base
5-Year Drought (High Prices)
5-Year Drought (Expected Prices)
5-Year Drought (Low Prices)

Source: derived from Manitoba Hydro data and model runs.

Exhibit J-23: No Sale Scenario Impact on Retained Earnings of 5-Year Drought Commencing in 2025

Retained Earnings ($ millions)

[redacted]

MH

Alternative Base
5-Year Drought (High Prices)
5-Year Drought (Expected Prices)
5-Year Drought (Low Prices)

Source: derived from Manitoba Hydro data and model runs.

As illustrated, there should be sufficient Retained Earnings to withstand the drought assuming low, expected prices, and high prices.

Exhibit J-24: No Sale Scenario Impact on Debt Ratio of 5-Year Drought Commencing in 2025

4.7.

MH

Debt Ratio (%)

[redacted]

Alternative Base
5-Year Drought (High Prices)
5-Year Drought (Expected Prices)
5-Year Drought (Low Prices)

Source: derived from Manitoba Hydro data and model runs.

As indicated, assuming low and expected prices, the Debt Ratio target will be achieved throughout the period. Assuming high prices, the Debt Ratio will exceed the target and reach 78% in 2030 and return to below target levels by 2031.

Five Year Drought Risk - Sale Scenario Compared to No Sale Scenario

In this section we compare the financial impact of the Sale Scenario to the No Sale Scenario and consider the impact on the quantification of drought risk under each scenario.

As indicated in the analysis above, the Sale Scenario increases the financial impact on Net Income over a five year drought commencing at various times compared to a No Sale Scenario. However, the ability to withstand the financial impact of a five year drought is significantly improved under a Sale Scenario, as there is increased Retained Earnings and improved Debt Ratios in comparison to the No Sale Scenario.

Five Year Drought Sale vs. No Sale Scenario 1

The net change in the reduction in Net Income of a Sale Scenario compared to No Sale Scenario, assuming a five year drought commencing in 2013 with low, expected and high export and natural gas prices is as follows.

Exhibit J-25: Impact of Five Year Drought – Commencing in 2013 on a Sale vs. No Sale Scenario

Impact of Five Year Drought - Commencing in 2013 on a Sale vs. No Sale Scenario ($ millions)						
Forecast Fiscal Year	**2013/14**	**2014/15**	**2015/16**	**2016/17**	**2017/18**	**5-Year Total**
Water Flow Year	**1937**	**1938**	**1939**	**1940**	**1941**	**1937-1941**
LOW PRICES						
Revenue						
Extra Provincial Sales	(0.1)	-	(0.6)	0.8	(0.1)	-
Expenses (Recovery)						
Water Rentals	-	-	-	0.2	0.1	**0.3**
Fuel & Power Purchased	0.2	0.7	(0.1)	(3.3)	(5.2)	**(7.7)**
Increase in Net Income (excluding financing costs)	**(0.3)**	**(0.7)**	**(0.5)**	**3.9**	**5.0**	**7.4**
Changes in Energy (GWh)						
Hydro Generation	(3.5)	(3.3)	(0.1)	78.5	30.2	**101.8**
Extra Provincial Sales	0.7	3.9	(3.2)	28.3	(9.1)	**20.6**
Fuel & Power Purchased	4.1	7.3	(3.0)	(50.2)	(39.5)	**(81.3)**
EXPECTED PRICES						
Revenue						
Extra Provincial Sales	0.1	-	(0.7)	1.2	(0.2)	**0.4**
Expenses (Recovery)						
Water Rentals	-	-	-	0.2	0.1	**0.3**
Fuel & Power Purchased	0.4	0.9	(0.2)	(4.4)	(6.6)	**(9.9)**
Increase in Net Income (excluding financing costs)	**(0.3)**	**(0.9)**	**(0.5)**	**5.4**	**6.3**	**10.0**
Changes in Energy (GWh)						
Hydro Generation	(4.6)	(3.5)	0.7	79.1	27.4	**99.2**
Extra Provincial Sales	1.7	4.6	(2.5)	29.6	(9.1)	**24.3**
Fuel & Power Purchased	6.3	8.0	(3.1)	(49.5)	(36.5)	**(74.8)**
HIGH PRICES						
Revenue						
Extra Provincial Sales	(0.1)	0.4	(0.9)	1.6	(12.0)	**(11.0)**
Expenses (Recovery)						
Water Rentals	-	-	-	0.3	0.1	**0.4**
Fuel & Power Purchased	0.4	1.7	(0.2)	(6.3)	(14.4)	**(18.8)**
Increase in Net Income (excluding financing costs)	**(0.5)**	**(1.3)**	**(0.7)**	**7.6**	**2.3**	**7.4**
Changes in Energy (GWh)						
Hydro Generation	(4.0)	(4.1)	(0.8)	77.6	19.7	**88.4**
Extra Provincial Sales	0.7	8.2	(3.0)	27.3	(62.0)	**(28.8)**
Fuel & Power Purchased	4.7	11.9	(2.1)	(50.3)	(81.7)	**(117.5)**

Source: derived from Manitoba Hydro data and model runs.

Five Year Drought Sale vs. No Sale Scenario 2

The net change in the reduction of Net Income of a Sale Scenario compared to No Sale Scenario, assuming a five year drought commencing in 2019 with low, expected and high export and natural gas prices is as follows.

Exhibit J-26: Impact of Five Year Drought – Commencing in 2019 on a Sale vs. No Sale Scenario

Impact of Five Year Drought - Commencing in 2019 on a Sale vs. No Sale Scenario ($ millions)						
Forecast Fiscal Year	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**	**5-Year Total**
Water Flow Year	**1937**	**1938**	**1939**	**1940**	**1941**	**1937-1941**
LOW PRICES						
Revenue						
Extra Provincial Sales	41.2	22.5	11.4	95.2	45.4	**215.7**
Expenses (Recovery)						
Water Rentals	0.4	(2.5)	(4.4)	0.8	(2.5)	**(8.2)**
Fuel & Power Purchased	28.4	23.8	33.3	69.2	114.3	**269.0**
Reduction in Net Income (excluding financing costs)	**12.4**	**1.2**	**(17.5)**	**25.2**	**(66.4)**	**(45.1)**
Changes in Energy (GWh)						
Hydro Generation	140.1	(723.2)	(1,314.3)	257.4	(760.6)	**(2,400.6)**
Extra Provincial Sales	694.9	259.8	(13.6)	1,937.6	1,011.8	**3,890.5**
Fuel & Power Purchased	554.9	982.8	1,300.5	1,680.3	1,772.2	**6,290.7**
EXPECTED PRICES						
Revenue						
Extra Provincial Sales	55.1	61.5	11.4	128.5	62.0	**318.5**
Expenses (Recovery)						
Water Rentals	0.5	(2.4)	(4.4)	0.9	(2.7)	**(8.1)**
Fuel & Power Purchased	37.5	71.6	45.7	97.7	169.9	**422.4**
Reduction in Net Income (excluding financing costs)	**17.1**	**(7.7)**	**(29.9)**	**29.9**	**(105.2)**	**(95.8)**
Changes in Energy (GWh)						
Hydro Generation	126.6	(720.4)	(1,311.2)	259.1	(789.5)	**(2,435.4)**
Extra Provincial Sales	665.9	489.4	(45.0)	1,901.0	981.7	**3,993.0**
Fuel & Power Purchased	539.1	1,209.6	1,266.4	1,641.9	1,770.9	**6,427.9**
HIGH PRICES						
Revenue						
Extra Provincial Sales	111.6	22.9	(26.6)	138.3	67.2	**313.4**
Expenses (Recovery)						
Water Rentals	0.4	(2.3)	(4.3)	0.8	(2.6)	**(8.0)**
Fuel & Power Purchased	75.2	41.0	23.9	116.0	243.2	**499.3**
Reduction in Net Income (excluding financing costs)	**36.0**	**(15.8)**	**(46.2)**	**21.5**	**(173.4)**	**(177.9)**
Changes in Energy (GWh)						
Hydro Generation	112.5	(691.8)	(1,258.1)	244.9	(781.0)	**(2,373.5)**
Extra Provincial Sales	853.3	115.0	(253.2)	1,659.1	861.9	**3,236.1**
Fuel & Power Purchased	740.6	807.1	1,004.9	1,414.3	1,642.8	**5,609.7**

Source: derived from Manitoba Hydro data and model runs.

Five Year Drought Sale vs. No Sale Scenario 3

The net change in the reduction of Net Income of a Sale Scenario compared to No Sale Scenario, assuming a five year drought commencing in 2025 with low, expected and high export and natural gas prices is as follows.

Exhibit J-27: Impact of Five Year Drought – Commencing in 2025 on a Sale vs. No Sale Scenario

Impact of Five Year Drought - Commencing in 2025 on a Sale vs. No Sale Scenario ($ millions)						
Forecast Fiscal Year Water Flow Year	**2025/26 1937**	**2026/27 1938**	**2027/28 1939**	**2028/29 1940**	**2029/30 1941**	**5-Year Total 1937-1941**
LOW PRICES						
Revenue						
Extra Provincial Sales	(18.2)	34.6	107.6	121.4	56.2	**301.6**
Expenses (Recovery)						
Water Rentals	(1.5)	(3.3)	(4.1)	(3.8)	(5.5)	**(18.2)**
Fuel & Power Purchased	5.8	108.9	192.8	193.6	222.9	**724.0**
Reduction In Net Income (excluding financing costs)	**(22.5)**	**(71.0)**	**(81.1)**	**(68.4)**	**(161.2)**	**(404.2)**
Changes in Energy (GWh)						
Hydro Generation	(445.5)	(981.8)	(1,224.5)	(1,131.8)	(1,625.5)	**(5,409.1)**
Extra Provincial Sales	(118.3)	599.6	1,421.5	1,537.9	1,110.6	**4,551.3**
Fuel & Power Purchased	327.3	1,581.6	2,646.0	2,669.7	2,736.1	**9,960.7**
EXPECTED PRICES						
Revenue						
Extra Provincial Sales	(20.3)	51.5	123.7	182.7	23.9	**361.5**
Expenses (Recovery)						
Water Rentals	(1.4)	(3.3)	(4.2)	(3.8)	(5.4)	**(18.1)**
Fuel & Power Purchased	15.2	159.2	258.9	290.7	272.9	**996.9**
Reduction in Net Income (excluding financing costs)	**(34.1)**	**(104.4)**	**(131.0)**	**(104.2)**	**(243.6)**	**(617.3)**
Changes in Energy (GWh)						
Hydro Generation	(405.6)	(973.0)	(1,236.7)	(1,137.9)	(1,632.5)	**(5,385.7)**
Extra Provincial Sales	(59.7)	609.0	1,206.4	1,542.4	816.0	**4,114.1**
Fuel & Power Purchased	345.9	1,582.1	2,443.2	2,680.3	2,448.6	**9,500.1**
HIGH PRICES						
Revenue						
Extra Provincial Sales	(19.4)	50.3	127.2	252.1	(5.6)	**404.6**
Expenses (Recovery)						
Water Rentals	(1.4)	(3.1)	(4.3)	(3.8)	(4.9)	**(17.5)**
Fuel & Power Purchased	30.4	201.1	325.8	411.4	320.3	**1,289.0**
Reduction in Net Income (excluding financing costs)	**(48.4)**	**(147.7)**	**(194.3)**	**(155.5)**	**(321.0)**	**(866.9)**
Changes in Energy (GWh)						
Hydro Generation	(417.8)	(941.5)	(1,268.2)	(1,157.2)	(1,481.2)	**(5,265.9)**
Extra Provincial Sales	(18.6)	486.1	988.0	1,478.2	616.8	**3,550.5**
Fuel & Power Purchased	399.5	1,427.7	2,256.3	2,635.4	2,098.3	**8,817.2**

Source: derived from Manitoba Hydro data and model runs.

As illustrated, the Sale Scenario provides a nominal improvement to Net Income assuming a five year drought beginning in 2013, and significantly increases the reduction to Net Income for five year droughts beginning in 2019 and 2025.

The following graphs summarize the Retained Earnings and Debt Ratios of a five year drought commencing 2013, 2019, and 2025 assuming a Sale Scenario and No Sale Scenario compared to the Alternative Base financial forecast.

Exhibit J-28: Comparison of Sale vs. No Sale for Scenarios (Low Prices)

4.7. MH

[redacted]

Source: derived from Manitoba Hydro data and model runs.

KPMG

Exhibit J-29: Comparison of Sale vs. No Sale for Scenarios (Expected Prices)

MH

[redacted]

Source: derived from Manitoba Hydro data and model runs.

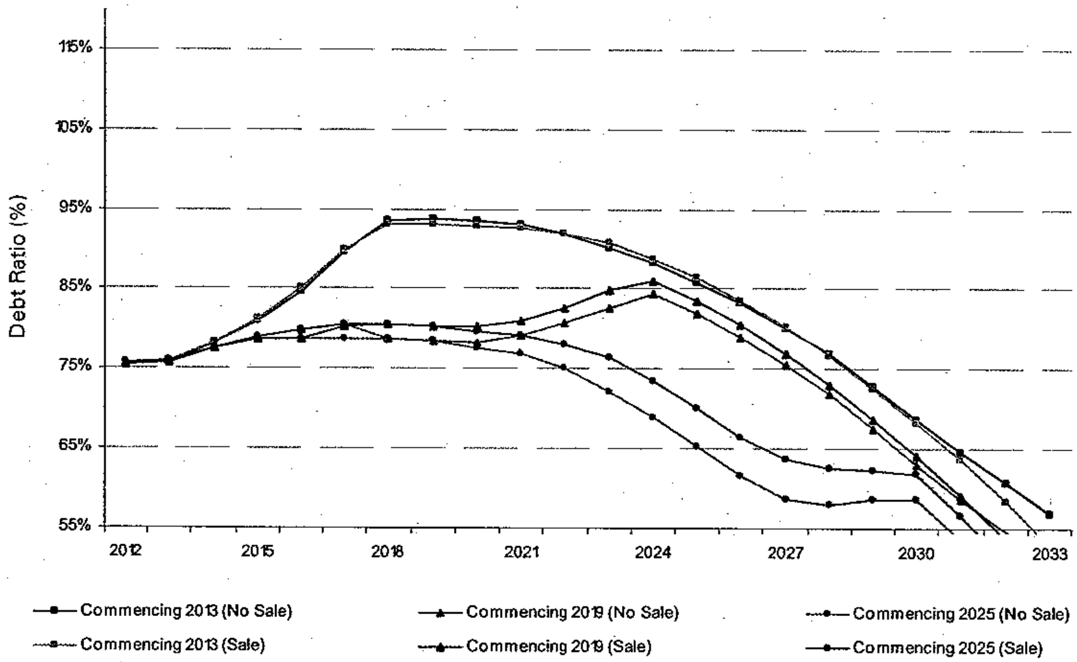
Exhibit J-30: Comparison of Sale vs. No Sale for Scenarios (High Prices)

MH

[redacted]

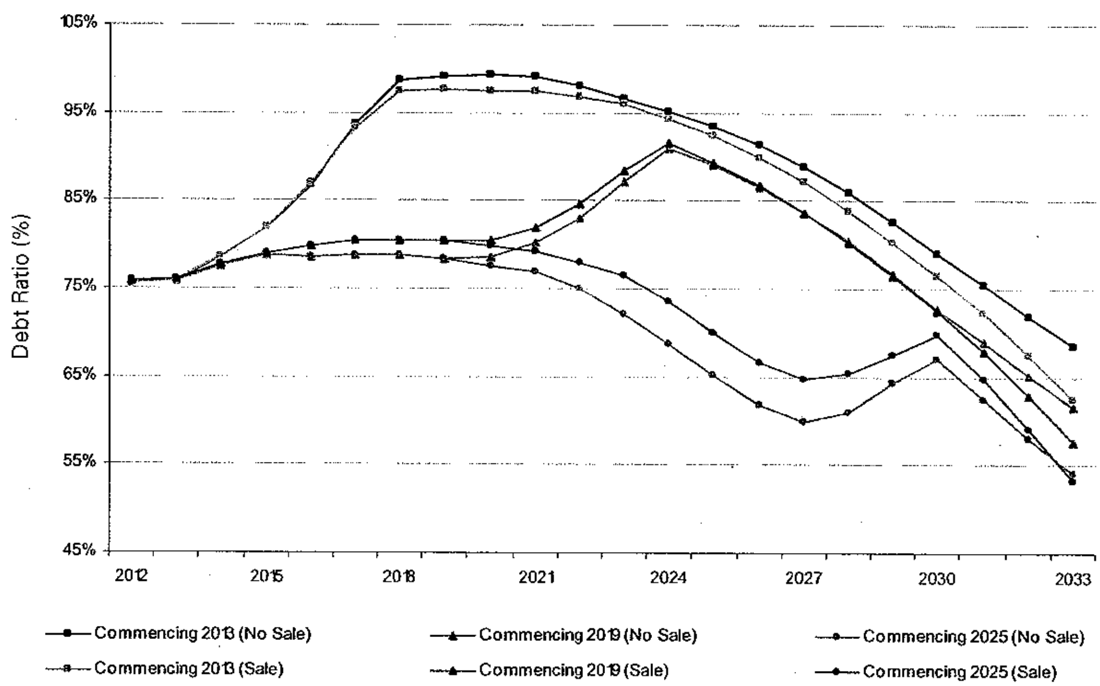
Source: derived from Manitoba Hydro data and model runs.

Exhibit J-31: Comparison of Sale vs. No Sale Scenarios (Low Prices)



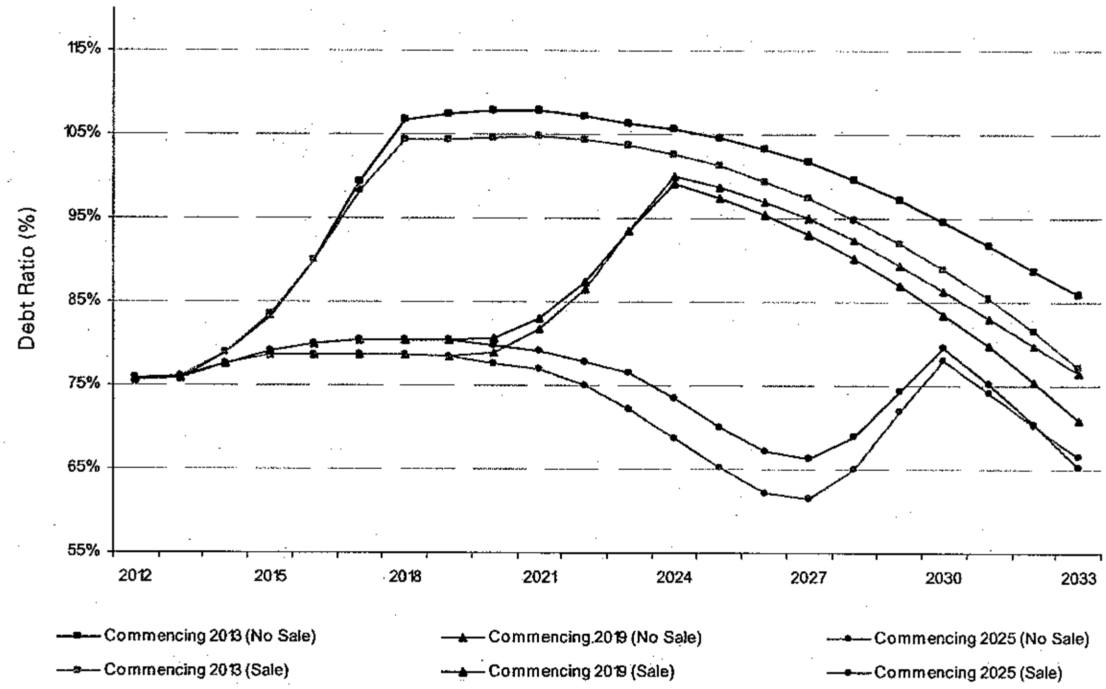
Source: derived from Manitoba Hydro data and model runs.

Exhibit J-32: Comparison of Sale vs. No Sale Scenarios (Expected Prices)



Source: derived from Manitoba Hydro data and model runs.

Exhibit J-33: Comparison of Sale vs. No Sale Scenarios (High Prices)



Source: derived from Manitoba Hydro data and model runs.

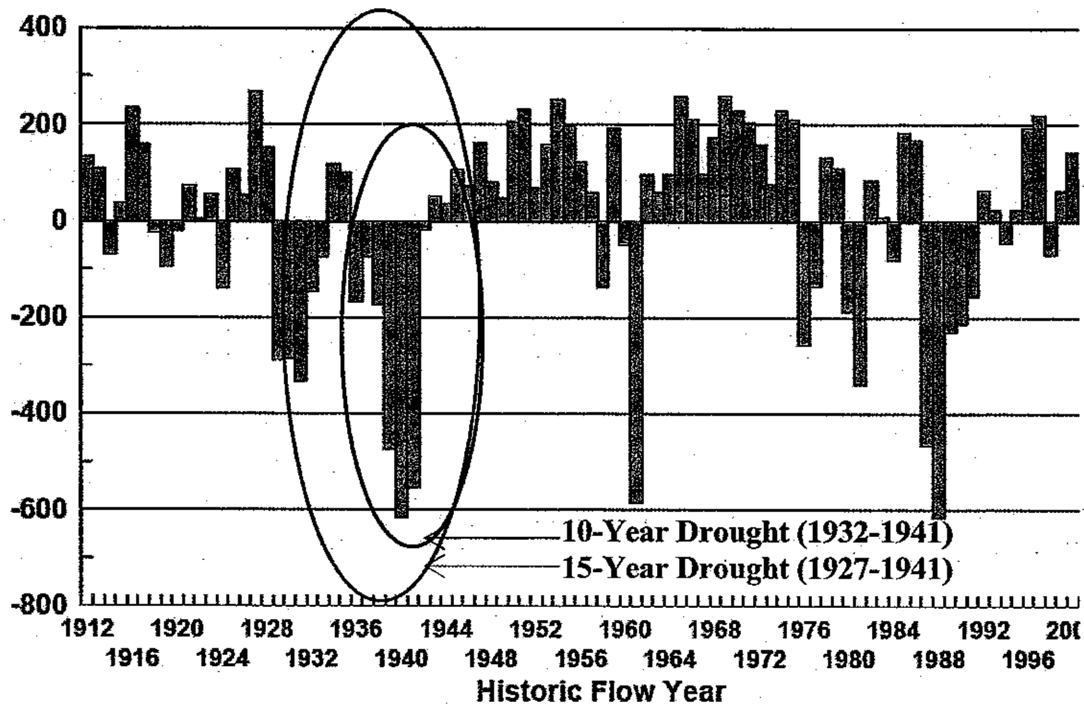
As previously stated, the Sale Scenario provides MH with improved Retained Earnings and Debt Ratios compared to the No Sale Scenario. The improved Retained Earnings and Debt Ratios are due primarily to the increased surplus export sales associated with the new generation and US transmission interconnection capabilities. The new US transmission interconnection capabilities also provide for increased import capabilities in low flow periods, which should reduce costs required to run the thermal gas units in order to meet Manitoba load requirements.

Accordingly, the Sale Scenario appears to reduce the overall risk of a five year drought compared to a No Sale Scenario, since it provides greater Retained Earnings and improved Debt Ratios to withstand the financial impact of a five year drought.

Additional Low Flow Scenarios

In this section we considered additional low water flow conditions to supplement the analysis and determine the financial impact for a reoccurrence of the worst ten years of historical low flows on record (1932 to 1941), and the worst fifteen years of historical low flows on record (1927 to 1941), as illustrated in the graph below, in a Sale Scenario commencing at various times.

Exhibit J-34: Variation of Flow Related Revenue ($ million)



Source: Manitoba Hydro

Ten Year Low Flow Period

As indicated in the graph above, the ten year low flows include multiple low flow periods with only two positive flow years in 1934 and 1935. A summary of the ten years low flow water conditions in a Sale Scenario is provided below.

Ten Year Low Flow Scenario 1

This scenario assume a recurrence of the worst ten years of low flows on record (1932–1941) commencing in 2013, returning to average revenues for all 94 flow conditions in the periods preceding and following the low flow period assuming expected and high prices. All other assumptions have been held constant and no adjustments were made to projected rate increases to consumers

Ten Year Low Flow Scenario 2

This scenario assume a recurrence of the worst ten years of low flows on record (1932–1941) commencing in 2019, coinciding with the in service date for Keeyask and construction stage of Conawapa, returning to average revenues for all 94 flow conditions in the periods preceding and following the low flow period assuming expected and high prices. All other assumptions have been held constant and no adjustments were made to projected rate increases to consumers.

Ten Year Low Flow Scenario 3

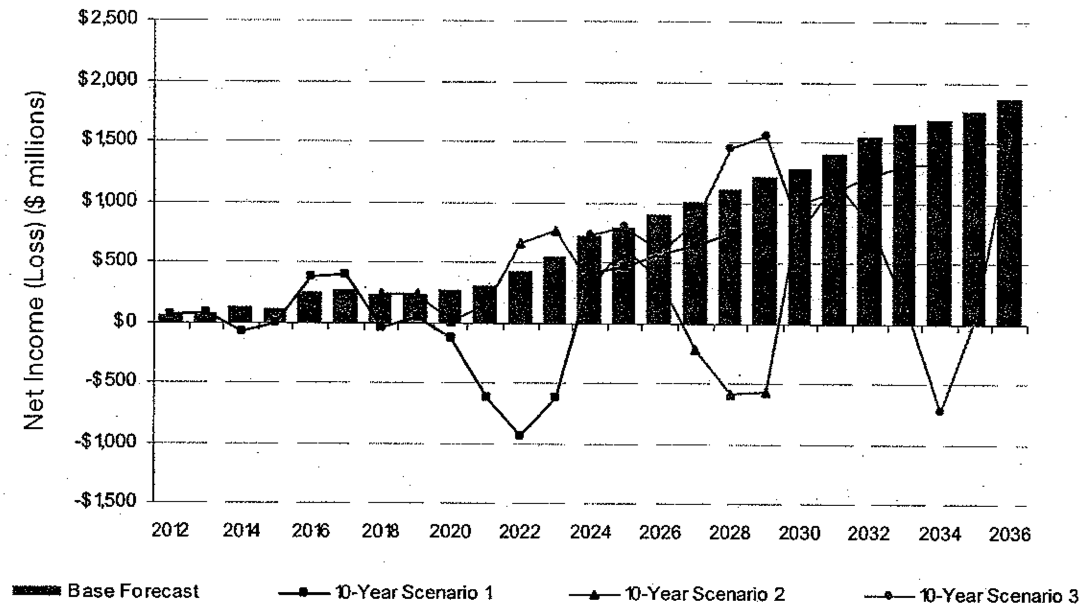
This scenario assume a recurrence of the worst ten years of low flows on record (1932–1941) commencing in 2025, coinciding with the in service date of Conawapa, returning to average revenues for all 94 flow conditions in the periods preceding and following the low flow period assuming expected and high prices. All other assumptions have been held constant and no adjustments were made to projected rate increases to consumers.

Exhibit J-35: Summary of Ten Year Low Flow Scenarios

	Cumulative Reduction In Net Income	Retained Earnings (Deficit) At The End of Period
Scenario 1 - Drought Starting 2013		
- Expected Price	4,412	778
- High Prices	6,376	(1,186)
Scenario 2 - Drought Starting 2019		
- Expected Price	5,842	5,127
- High Prices	8,363	2,606
Scenario 3 - Drought Starting 2025		
- Expected Price	6,995	13,353
- High Prices	10,105	10,243

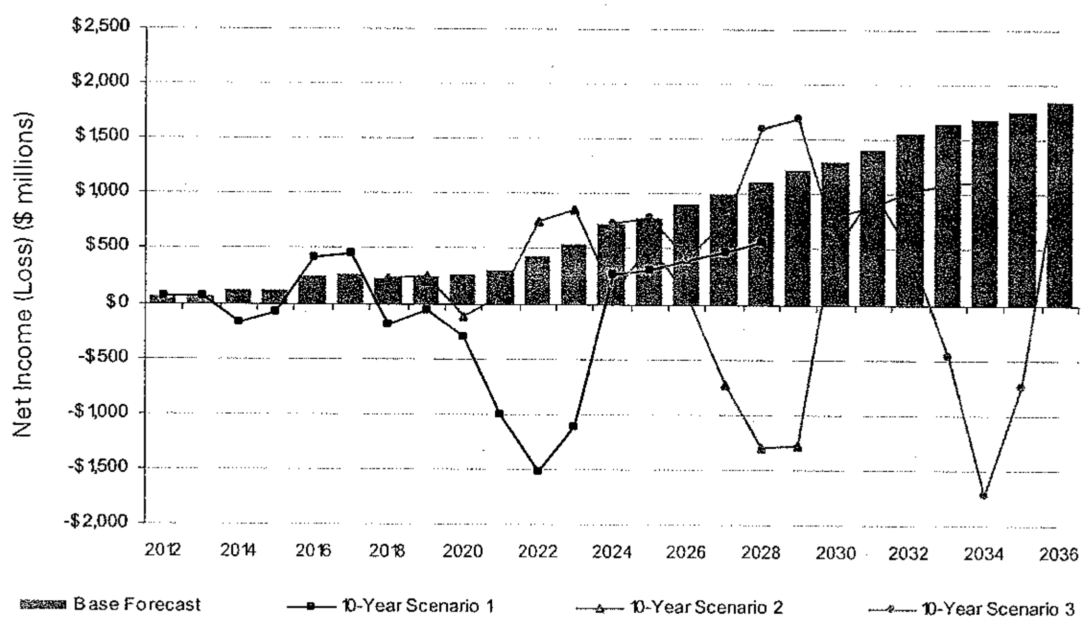
The estimated financial impact including financing costs of a ten year low flow period on Net Income, Retained Earnings and the target Debt Ratio assuming expected and high prices is provided below.

Exhibit J-36: Impact of 10-Year Scenario on Net Income (Expected Prices)



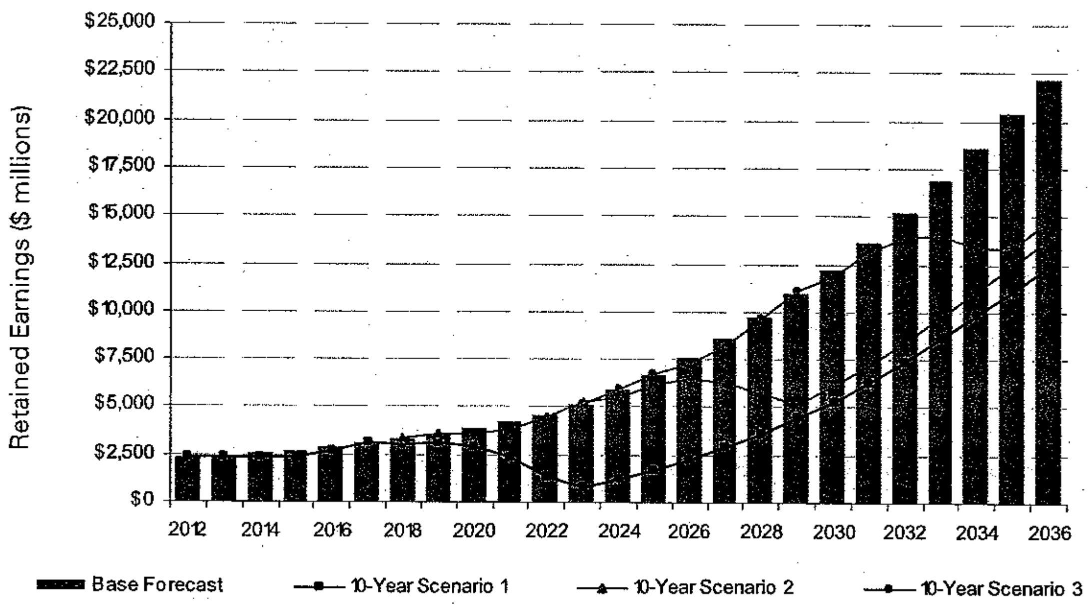
Source: derived from Manitoba Hydro data and model runs.

Exhibit J-37: Impact of 10-Year Scenario on Net Income (High Prices)



Source: derived from Manitoba Hydro data and model runs.

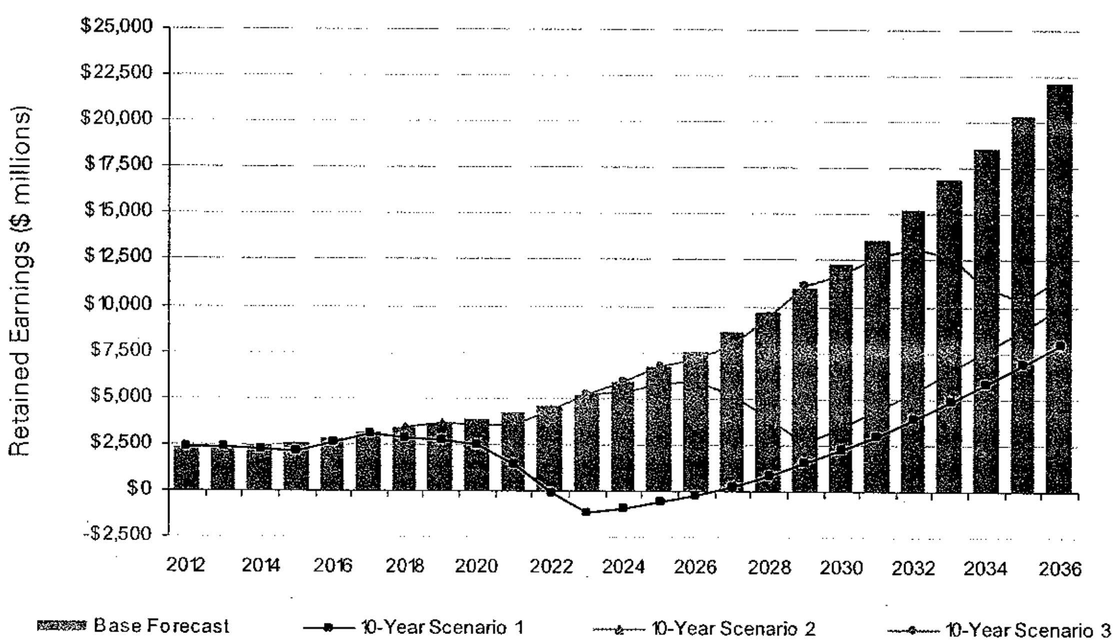
Exhibit J-38: Impact of 10-Year Scenario on Retained Earnings (Expected Prices)



Source: derived from Manitoba Hydro data and model runs.

As indicated, assuming expected prices, there should be sufficient Retained Earnings to cover the estimated financial impact in all ten year low flow periods.

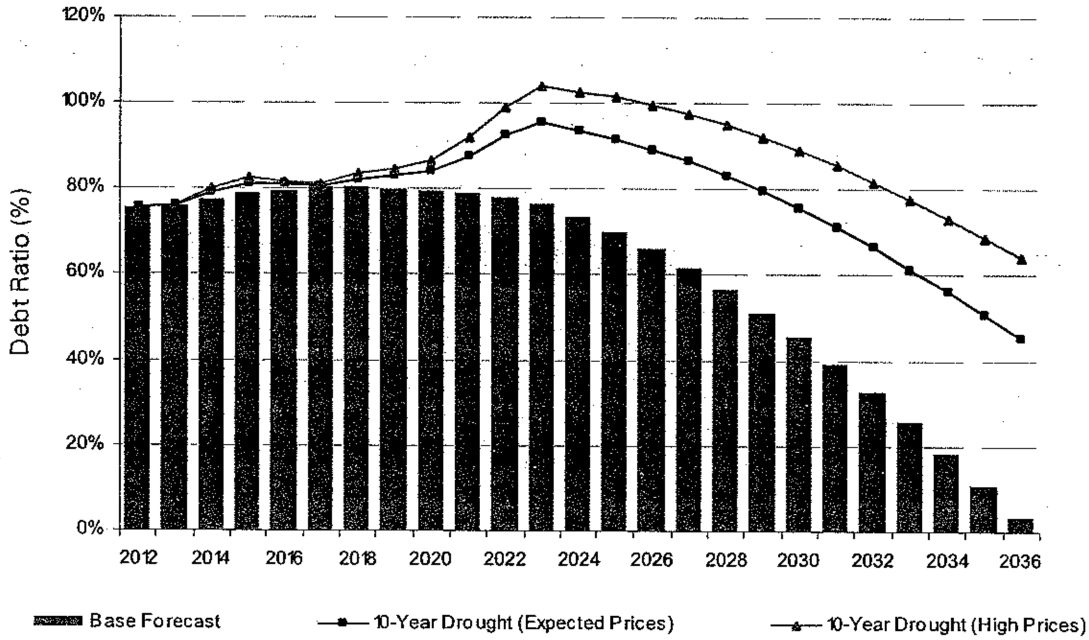
Exhibit J-39: Impact of 10-Year Scenario on Retained Earnings (High Prices)



Source: derived from Manitoba Hydro data and model runs.

The impact of ten year low flows assuming high prices will result in a Deficit in the period 2023 to 2026 assuming a commencement in 2013, and sufficient Retained Earnings in all other periods to provide for the financial impact of a ten year low flow period.

Exhibit J-40: Impact of 10-Year Drought on Debt Ratio (Expected and High Prices)



Source: derived from Manitoba Hydro data and model runs.

The target Debt Ratio is not met assuming expected and high prices with the Debt Ratio returning to target in 2030 for expected prices and 2034 for high prices.

Fifteen Year Low Flow Period

As indicated in Variation of Flow Related Revenue ($ million) graph above, the fifteen year low flow year includes multiple low flow periods with positive flows in four years, 1927, 1928, 1934 and 1935 out of the fifteen year period. This fifteen year low flow period essentially includes two drought periods 1929 to 1933 and 1936 to 1941. A summary of the fifteen years low flow water conditions in a Sale Scenario is provided below.

Fifteen Year Low Flow Scenario 1

This scenario assume a recurrence of the worst fifteen years of low flows on record (1928–1941) commencing in 2013, returning to average revenues for all 94 flow conditions in the periods preceding and following the low flow period assuming expected and high prices. All other assumptions have been held constant and no adjustments were made to projected rate increases to consumers. The fifteen year low flow scenario is essentially two separate droughts within a fifteen year span with the largest occurring at the end of the period.

Fifteen Year Low Flow Scenario 2

This scenario assume a recurrence of the worst fifteen years of low flows on record (1928–1941) commencing in 2019/20, coinciding with the in service date for Keeyask and construction stage of Conawapa, returning to average revenues for all 94 flow conditions in the periods preceding and following the low flow period assuming expected and high prices. All other assumptions have been held constant and no adjustments were made to projected rate increases to consumers

Fifteen Year Low Flow Scenario 3

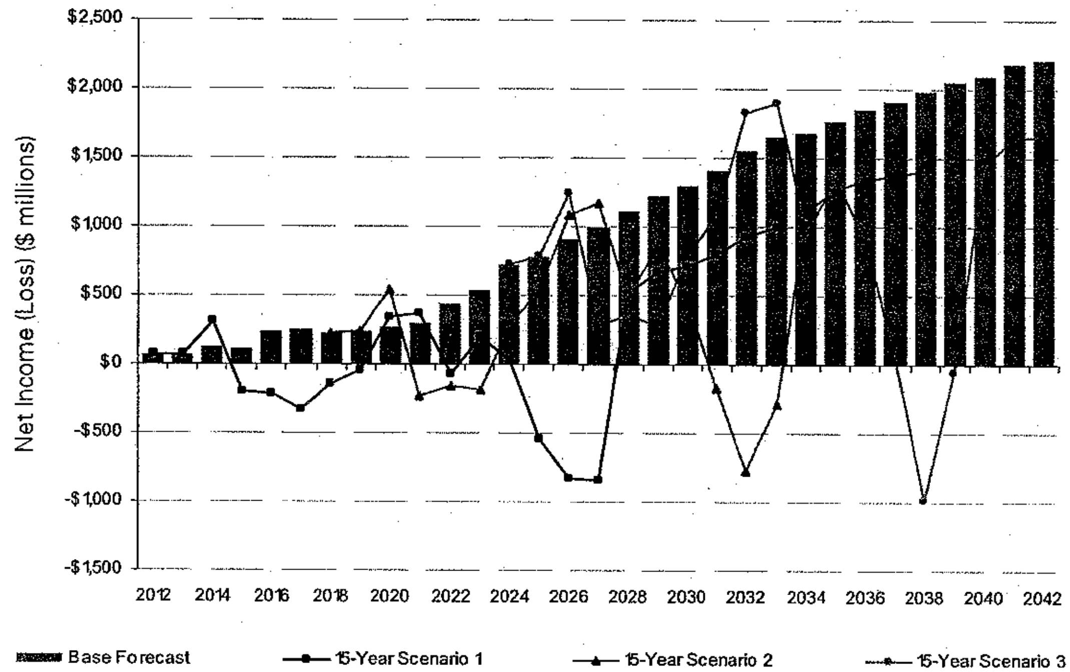
This scenario assume a recurrence of the worst fifteen years of low flows on record (1928–1941) commencing in 2025, coinciding with the in service date of Conawapa, returning to average revenues for all 94 flow conditions in the periods preceding and following the low flow period assuming expected and high prices. All other assumptions have been held constant and no adjustments were made to projected rate increases to consumers.

Exhibit J-41: Summary of Fifteen Year Low Flow Scenarios

	Cumulative Reduction In Net Income	Retained Earnings (Deficit) At The End of Period
Scenario 1 - Drought Starting 2013		
- Expected Price	8,805	940
- High Prices	12,508	(2,763)
Scenario 2 - Drought Starting 2019		
- Expected Price	10,195	8,384
- High Prices	14,748	3,831
Scenario 3 - Drought Starting 2025		
- Expected Price	12,130	18,132
- High Prices	17,520	12,742

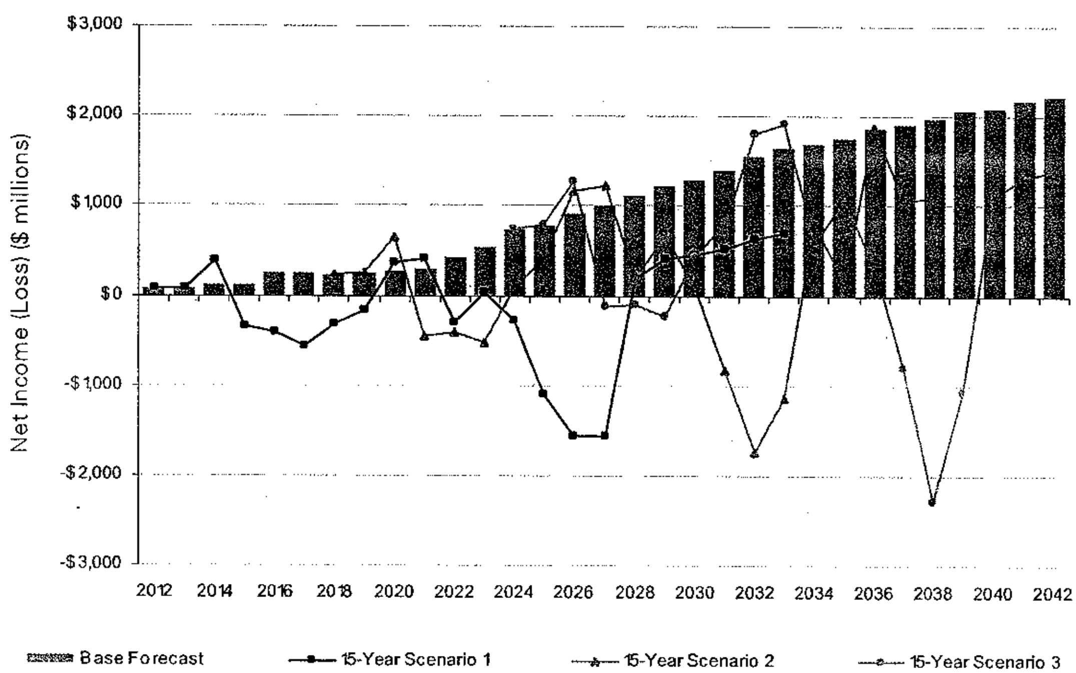
The estimated financial impact including financing costs of a fifteen year low flow period on Net Income, Retained Earnings, and the target Debt Ratio assuming expected and high prices is provided below.

Exhibit J-42: Impact of 15-Year Scenario on Net Income (Expected Prices)



Source: derived from Manitoba Hydro data and model runs.

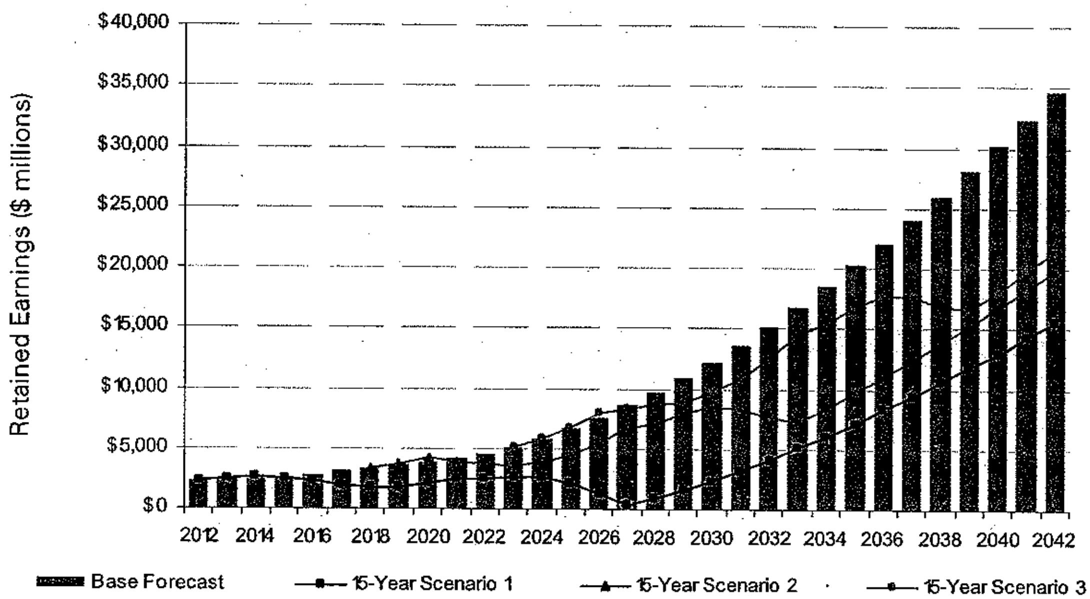
Exhibit J-43: Impact of 15-Year Scenario on Net Income (High Prices)



Source: derived from Manitoba Hydro data and model runs.

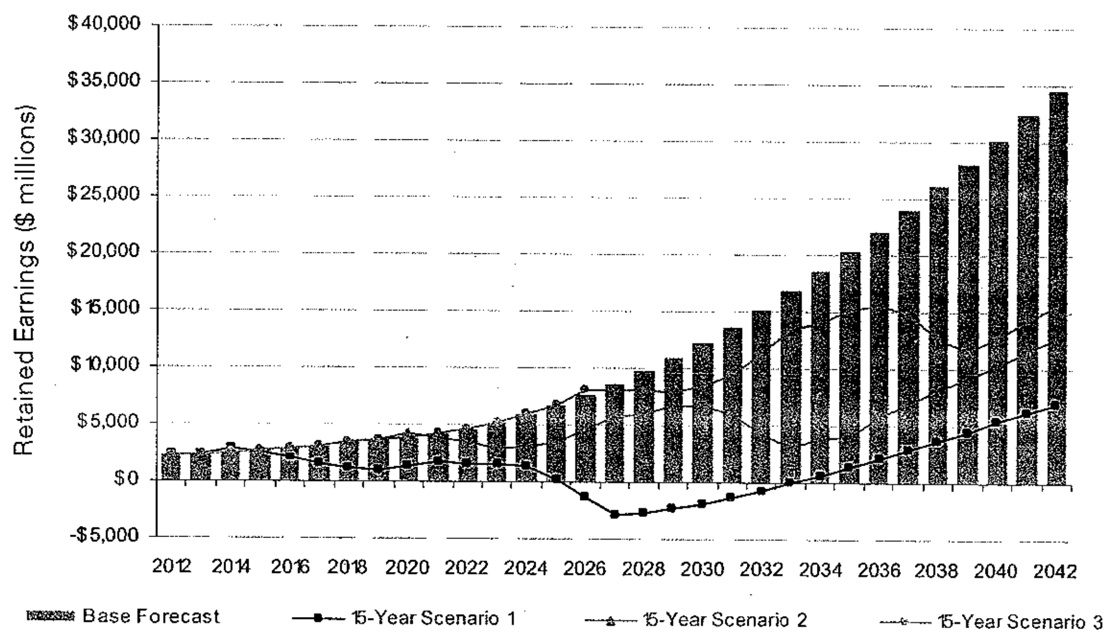
The impact on Net Income under a fifteen year low flow period is outlined below.

Exhibit J-44: Impact of 15-Year Scenario on Retained Earnings (Expected Prices)



Source: derived from Manitoba Hydro data and model runs.

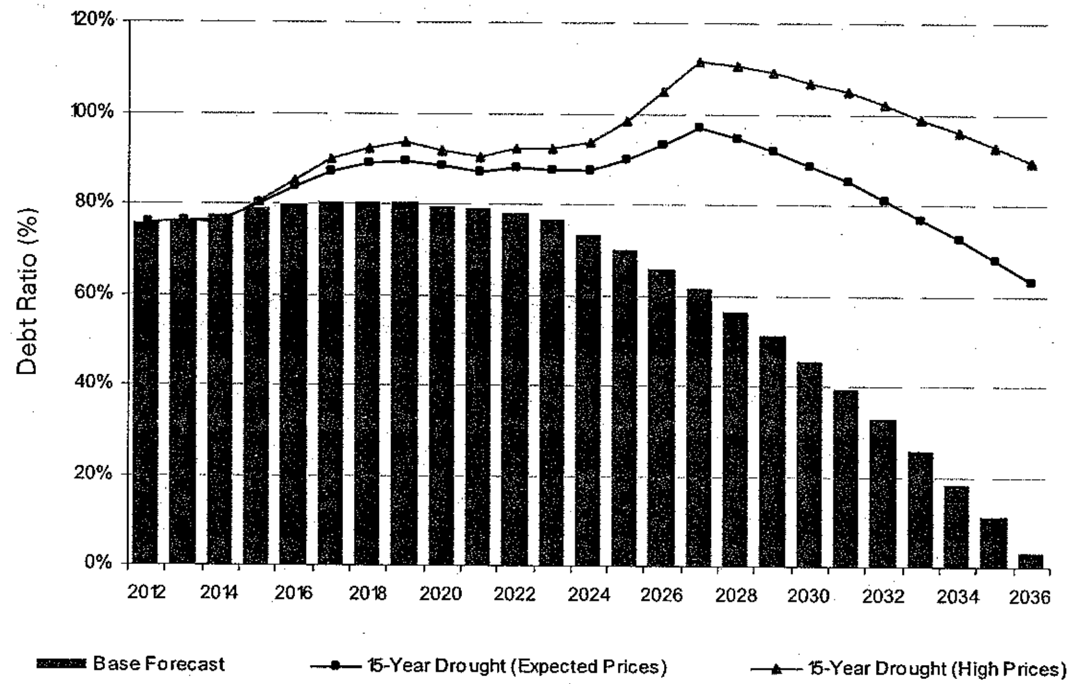
Exhibit J-45: Impact of 15-Year Scenario on Retained Earnings (High Prices)



Source: derived from Manitoba Hydro data and model runs.

As indicated, the fifteen year low flow period beginning in 2013 will result in no Deficit assuming expected prices and Deficits in the periods 2026 to 2033 assuming high prices.

Exhibit J-46: Impact of 15-Year Drought on Debt Ratio (Expected vs. High Prices)



Source: derived from Manitoba Hydro data and model runs.

Given the impact of low flow years coinciding with new generation investments, the fifteen year low flow scenario exceeds the Debt Ratio target of 75% assuming both expected and high prices.

K

Appendix K: Case Study Findings Relating to Risk Governance

This appendix presents our findings related to risk governance approaches of other electric utilities. We compare those practices to Manitoba Hydro. Its relevance is to demonstrate that a variety of risk governance approaches are in place, largely driven by the operating characteristics of the utility, adoption of leading practices and the business and regulatory environment in which they operate.

KPMG reviewed 14 other electric utilities as part of its case study review. For the purposes of our analysis on risk governance we have considered 13 of the 14 electric utilities. The utility excluded from our analysis is only responsible for power generation, and does not engage in any power sales or trading activities; thus it is not a relevant comparator.

We begin this appendix by describing the risk governance roles, responsibilities and reporting relationships in place at the utilities we researched. We then describe the major risk governance policies in place at the case study utilities.

Roles, Responsibilities and Reporting Relationship

KPMG's case study review revealed that there is a wide range of governance structures being utilized across the industry. There is no "one-size-fits-all" or "one best model" governance structure, as the particulars about an electric utility's regulatory structure, trading activity, generation mix and other factors affect the amount and types of governance and oversight that is needed to effectively govern the organization. While some of the utilities reviewed have moved closer to the leading practice, several have a structure that incorporates only elements of the leading practice recommendations. The balance of this section will describe the case study findings on:

- Risk management roles and responsibilities;
- Reporting relationships; and
- The overall risk governance structure.

Roles and Responsibilities

This section describes the risk management roles and responsibilities identified in our case study review. The leading practices for risk management roles and responsibilities indicate that the board, risk oversight committee, and middle office are each important to a sound risk governance structure. The case study review indicates that almost all of the organizations in our sample have each of these specific roles in place.

Board of Directors

In all of the organizations, the Board of Directors is responsible for establishing the risk appetite of the organization and overseeing risk management activities. This role is typically delegated to the audit or finance committee of the board. Only one organization has a board-level committee that is exclusively focused on risk activities. In the majority of organizations these roles are conducted by the audit committee which also has other roles and responsibilities within the organization.

Risk Oversight Committee

Eleven of the 13 organizations have a distinct risk oversight committee. Of the two organizations that do not, one has an oversight committee for its finance division. This group covers the responsibilities of the risk oversight committee, but also has a broader mandate for finance-related matters. The other organization that does not have an oversight committee does not have a senior-management level committee with responsibility for risk management. Its risk management activities are housed in its internal audit function.

Of the 11 organizations that have a distinct risk oversight committee, seven have one risk oversight committee that is responsible for managing both corporate risk and risk arising from trading activities. The other four have two risk oversight committees – one for managing corporate risk, and the other focused exclusively on trading risks. The four organizations that have two risk oversight committees have each re-organized their risk governance structure at some point over the last eight years. In each of the eleven organizations with a risk oversight committee, this committee is chaired by either the CFO or the CRO, or their designate.

For example, a northwestern United States utility with significant hydroelectric assets has an Executive Risk Committee that implements the risk management policy established by the board and determines the specific risk management procedures that the organization must operate under.

A major southern US utility with significant hydroelectric assets has two separate risk oversight committees, but instead of each committee having responsibility for a different type of risk, there is an Enterprise Risk Council that sits above its Risk Management Steering Committee. The Enterprise Risk Council is responsible for the highest level of risk oversight, and for communicating risks to the Board. The Risk Management Steering Committee reports to the Enterprise Risk Council and is responsible for reviewing risk management policies, reviewing business unit risk and risk management plans, recommending risk management processes and sponsoring special projects relating to cross-functional risk management activities, among other roles.

Another organization, located on the US west coast, has two risk oversight committees. It has an Enterprise Risk Management Committee and a Transacting Risk Management Committee. Each committee has a separate risk management group reporting up through it.

Middle Office

Twelve of the 13 organizations have defined front, middle and back office roles and responsibilities. One organization does not have a middle office function. This organization has outsourced its trading activities, and the middle office function is covered by the organization conducting its trading activities.

The make-up of the middle office is unique across organizations and is dependent on the mandate, trading activity, and policies and procedures of the organization. The number of personnel in our sample of middle offices range from one to thirteen dedicated professionals. Typically these professionals are segregated within the middle office either by type of risk (i.e., credit, market or operational risk) or by function (i.e., risk planning, risk reporting or risk control).

The middle office's responsibilities vary across the organizations. Sample responsibilities include:

- Ensuring trading activities are consistent with approved risk limits;
- Quantifying market, credit and operational risk exposures;
- Institutionalizing key risk analytics to identify potential financial risks under normal and extreme market conditions;
- Reporting risk metrics to senior management and the Board;

- Comparing trades to market comparables to protect against rogue trading;
- Assessing the risk of daily operations;
- Reviewing energy forecasting models
- Reviewing every transaction entered into the trading IT system for violations of protocol; and
- Performing counterparty credit analysis.

Four of the organizations interviewed have an enterprise risk management group that is separate from the middle office. The other nine organizations either do not have an enterprise risk management function, or this function is covered by the middle office staff.

Reporting Relationships

This section will describe the risk management reporting relationships identified in our case study review.

In each organization, the risk management function ultimately reports up to the Board of Directors. The level and types of reporting relationships below the Board level vary across organizations.

Six of the organizations have a Chief Risk Officer, or a senior management level individual who is responsible for overseeing the overall risk activities of the organizations. This individual either reports directly to the CEO or to the CFO. This individual chairs the risk oversight committee and heads up all risk management groups (middle office and enterprise risk management) within the organization At the other seven organizations, the senior-level risk management responsibility is covered by the CFO, or a designate from the finance department. Where there is no CRO there is a management-level individual who heads up the middle office activities. The reporting relationship of the middle office manager varies across organizations.

Of the seven organizations that do not have a CRO, six have a middle office and one does not. Of the six organizations that do have a middle office, three of the organization's middle office managers report to the CFO, the other three report up through the same channels as the Front Office.

There is only one organization that does not have a risk oversight committee or a middle office. In each of the 12 other organizations the middle office reports up through the risk oversight committee, as well as the reporting relationships described above.

Policies

KPMG's case study review revealed that every organization has a documented risk management policy. Each of the organizations also have more specific risk policies and procedures that outline risk limits, hedging strategies, approval structures, etc.

As an organization's risk management policies are considered commercially sensitive, KPMG was not able to obtain or review specific policy documents. Therefore, we are only able to comment on the existence of such policies, and not on their contents or extent to which the policies are followed within the organizations.

L

Appendix L: Risk Definitions

Accounting risk

The financial loss resulting from improper accounting or financial reporting.

Commodity price risk

The financial loss due to changes in underlying commodity prices adversely affecting cash flow, asset value and contract margins.

Construction risk

The financial loss resulting from issues impairing any phase of a physical construction project.

Credit risk

The financial loss when a counterparty fails to perform (i.e., defaults) on its contractual obligations. In assessing credit risk there are two issues to consider: counterparty creditworthiness and credit exposure. Counterparty creditworthiness is the counterparty's ability to perform on its obligations. Credit exposure is the value of outstanding obligations.

Environmental risk

The financial loss resulting from detrimental environmental (air, land, water) incidents (e.g., spill, emissions) and unexpected remediation costs.

Foreign exchange risk

Foreign currency risk is classified as either transaction or translation risk. *Transaction risk* is the risk that the net cash flow in connection with the settlement of foreign currency denominated assets, liabilities, firm commitments or anticipated transactions is adversely affected as a result of an unfavorable change in foreign currency exchange rates. *Translation risk* is the risk of a decrease in the net asset value of foreign operations as a result of an unfavorable change in foreign currency exchange rates.

Legal risk

The risk that a transaction is not consummated or is not enforceable due to legal barriers, including inadequate documentation, prohibition on a specific counterparty, court ruling or because of a change in or misinterpretation of applicable laws.

Liquidity risk

The risk of an adverse cost or return stemming from the lack of a liquid market for a commodity or financial instrument. Liquidity risk may arise because a transaction's size and/or contract tenor is large relative to typical trading volumes, contracts are complex and customized, or market conditions are unstable. Wide bid-ask spreads and large price movements indicate illiquid markets. An organization facing the need to quickly unwind illiquid positions or portfolio may either find it necessary to sell at prices below fair market value or not be able to sell the instrument at the desired time.

Market access risk

The financial loss resulting from legal, regulatory or market structure issues prevent or restrict the ability to dispose surplus power into a competitive marketplace.

Market risk

The financial loss resulting from adverse market movements in commodity prices due to risk factors such as weather, load and resource uncertainty, liquidity, and changes in price correlation.

Operational risk

The risk that transactions are not properly accounted for or processed due to human error, inadequate information systems, or insufficient operating standards resulting in financial loss.

The major sources of operational risk include:

- *Transaction risk* – The risk that energy transactions are not recorded into Hydro's deal capture system in an accurate and timely manner which in turn may cause downstream transaction processing errors (e.g., scheduling, settlements, billing, and accounting).
- *Model risk* – The risk that MH's model outputs fail to closely approximate or predict reality causing unexpected financial losses.
- *Systems risk* – The risk that PSO IT systems fail to record, measure and report risk.

Physical assets

A potential adverse event jeopardizing, curtailing, or impairing the company's assets or its ability to generate and deliver reliable energy services.

Product spread risk

The risk that the price differences between two product types of a certain commodity (e.g., off-peak power vs. peak power) or the price difference between two different commodities (e.g., natural gas vs. electricity) widens or narrows over time. The latter is also termed cross-commodity difference.

Regulatory risk

Potential financial event arising from public utility industry regulatory violations (e.g., rules misinterpretation, incorrect implementation, willful disregard), rate recovery disallowance (e.g., imprudent procurement costs), adverse regulatory amendments / rulings decisions or unfavorable regulatory environment.

Volume risk[1]

The financial loss resulting from quantity variances due to supply and demand imbalances (e.g., the risk of not having enough electricity to serve provincial load). Volume risk arises when demand is unexpectedly higher or lower than the amount forecasted/contracted. This results in a long or short exposure to the market.

---

[1] On the generation side, uncertainty of available generation capacity, such as water supply and the related uncertainty regarding future hydro power generation caused by adverse weather (e.g., temperature, precipitation or snow pack) is viewed as **drought risk** by MH.

M

Appendix M: Leading Practice Sources for Power Risk Management

Compendium of Leading Practice Sources	
Authoritative Source	**Description**
CCRO (Committee of Chief Risk Officers)	Originally formed in 2002, the CCRO was a coalition of 31 member companies representing of companies engaged in physical and financial trading and marketing of natural gas or power. The Committee is composed of Chief Risk Officers from leading companies that are active in both physical and financial energy trading and marketing. The Committee was formed in an effort to compile "best" risk management practices surrounding these activities. The CCRO established working groups to address four key areas - Organizational Independence and Governance, Valuation and Metrics, Credit Risk Management, and Risk Management Disclosures. In 2002, the Committee published six volumes of whitepapers on purported best practices as an initial step to codify industry standards.
COSO (Committee of Sponsoring Organizations of the Treadway Commission)	COSO was formed in 1985 and sponsored and funded by five US professional accounting associations: the American Institute of Certified Public Accountants, American Accounting Association, Financial Executives International, Institute of Internal Auditors and the Institute of Management Accountants. In 1992, COSO released a four volume report entitled "Internal Control - Integrated Framework" to help businesses and other entities assess and enhance their internal control systems. This report presented a common definition of internal control and provided a framework against which internal control systems may be assessed and improved.
G30 (The Group of 30) Global Derivatives Study Group	The G30 is a private, non-profit, international body composed of senior representatives of the private and public sectors and academia. It aims to deepen understanding of international economic and financial issues. G30 is currently chaired by the former Chairman of the Federal Reserve System, Paul Volcker. In 1993, the G30 commissioned the Global Derivatives Study Group to perform a study defining sound risk management practices addressing financial derivatives and valuation matters.

Board of Governors of the Federal Reserve System (The Federal Reserve Board)	The Federal Reserve Board is comprised of seven members appointed by the US government to manage the US central bank. In 1998, the Federal Reserve Board published the "Trading and Capital Markets Activities Manual" which provides independent examiners with guidance for reviewing capital markets and trading activities at all types of and sizes of financial institutions. The manual codifies procedures used in the review of capital markets and trading activities. It discusses the risks inherent in various activities, risk management and measurement techniques, appropriate internal controls, and the examination process from a global applicability, portfolio and general risk perspective.
FSA (Financial Services Authority)	The FSA is a regulatory body based in the United Kingdom responsible for regulating financial services, exchanges and firms in the UK. FSA supervises firms based on a risk-based framework called ARROW - the Advanced Risk-Response Operating Framework. In 2000, FSA published a Handbook of rules and guidance consisting of risk management standards segmented into seven modules. The specific module referenced in this report is "Senior Management Arrangements, Systems, and Controls" (SYSC). SYSC focuses on senior management responsibilities to ensure a firm has appropriate control, supervision and accountability systems in place, including appropriate operational risk systems and controls.
Energy Risk Magazine	Energy Risk Magazine is a specialized risk management publication headquartered in the UK used by energy risk professionals on topical issues facing the commodity trading sector.
OCC (Office of the Comptroller of the Currency)	The OCC was established in 1983 as a bureau of the US Treasury. The OCC is headed by the US Comptroller and the office has the authority to examine banks, approve / deny bank charters or changes to the banking structure, take supervisory actions against non-compliance, and issue rules and regulations governing bank investments, lending and other practices. In 2000, the OCC released a bulletin providing guidance to help institutions mitigate potential risks arising from reliance on computer-based financial models. The guidance outlines key model validation principles and the OCC's expectations for a sound model validation process.

Basel Committee on Banking Supervision	The Basel Committee provides a forum for regular cooperation on banking supervisory matters. The Committee is best known for its international standards on capital adequacy, the Core Principles for Effective Banking Supervision, and the Concordant on cross-border banking supervision. In 1996, The Basel Committee released a whitepaper titled "Supervisory Framework for the Use of 'Backtesting' in Conjunction with the Internal Models Approach to Market Risk Capital Requirements". This document presents the framework developed by the Committee for incorporating backtesting risk measurement models.
Counterparty Risk Management Policy Group (CRMPG)	The CRMPG was formed in 1999 to promote strong practices in counterparty credit and market risk management. In 2005, CRMPG release a whitepaper titled "Toward Greater Financial Stability: A Private Sector Perspective" to examine what additional steps should be taken by the private sector to promote the efficiency, effectiveness and stability of the global financial system. The whitepaper presents recommendations and guiding principles on risk management and credit risk management.