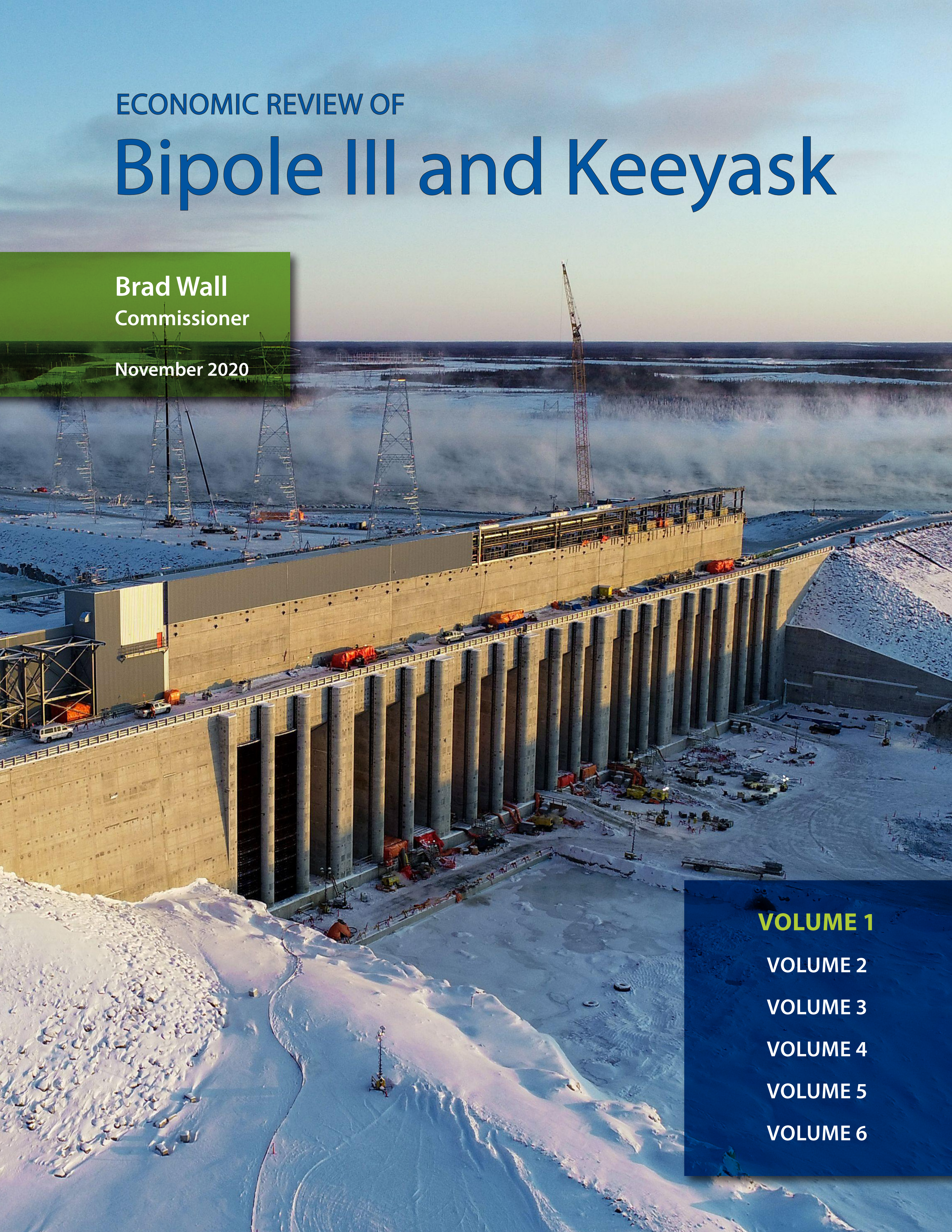
ECONOMIC REVIEW OF

Bipole III and Keeyask

Brad Wall
Commissioner

November 2020



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About This Report

This report is based on public documents from the Public Utilities Board and the Clean Environment Commission; internal reviews performed by Manitoba Hydro; documents from Manitoba Hydro and the Government Manitoba; and interviews and/or written submissions of past and present Manitoba Hydro executives, Government of Manitoba current and retired elected members, Government of Manitoba staff, and other stakeholders in the genesis, project plan development, approval and construction of the Keeyask Generating Station and Bipole III Transmission Line and Converter Stations.

Evidence cited in this report is noted from the actual documents attached to this report (see **Appendix A**). Where the actual document cannot be released for reasons of either commercial sensitivity or Cabinet confidentiality, the document is identified and evidence cited in context. The documents identified in the report do not represent every document that was reviewed and considered by the Commission. Access to Manitoba Hydro-Electric Board minutes, internal Manitoba Hydro memorandums, and Cabinet and Cabinet Committee agendas and minutes was a key element of this review and though some of it cannot be released in total, the insights gained were worthy of the limited ability to publish them in their entirety.

Interviews were conducted on a non-attributable basis. As a forward-looking report with a focus on the recommendations for future projects of this type, the Commissioner determined that full disclosure was more important than attribution. As such, verbatim transcripts were not made of conversations with the many stakeholders and individuals involved in the projects to identify gaps in organization structure, information flow, and influences on decisions. Citations are included throughout this report to indicate the information that the Commissioner received from those who participated through interviews and/or written submissions, but the citations do not name these participants, in accordance with the non-attributable basis of the interviews and requests for most written submissions to not be attributed.

ECONOMIC REVIEW
OF BIPOLE III & KEEYASK
COMMISSION

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November 13, 2020

Honourable Jeff Wharton
Minister of Crown Services
Room 314 Legislative Building
450 Broadway
Winnipeg, MB R3C 0V8

Dear Minister:

I am pleased to deliver to you the final report containing my findings and recommendations respecting Manitoba Hydro's development of the Keeyask Generating Station and the Bipole III transmission line and converter station project, in response to Orders in Council 301/2018 and 333/2019.

This report outlines the development of these projects based on public documents from the Public Utilities Board and the Clean Environment Commission, documents from Manitoba Hydro and the Government of Manitoba, and information received from stakeholders during interviews and in written submissions.

I would like to thank you and your Cabinet colleagues for appointing me to conduct this important inquiry. I hope that this report will be of some benefit and assistance to the Province.

Yours sincerely,

Brad Wall
Commissioner

Enclosure

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Foreword

> *Hydro power is Manitoba's oil … The main economic question in this election is do we build hydro or not?*
>
> – FORMER PREMIER SELINGER

This review and the subsequent recommendations are sectioned in accordance with the Terms of Reference set out in the mandating Orders in Council 301/2018 and 333/2019.

Building on previous reviews and studies and those that underpin this report, the Commission has attempted to quantify the impact of the Bipole III and Keeyask projects on Manitoba Hydro's financial health and more importantly, on the present and future customers of Manitoba Hydro.

The Commission is satisfied with the access granted to Cabinet documents, internal Manitoba Hydro documents, and the cooperation of those interviewed, including former and current Manitoba Hydro officials, stakeholders, partners and current and former elected officials.* It is worth noting the absence of documents related to Cabinet and Cabinet committees that the Commission would have expected to find. They were either not submitted or have yet to be archived.

It is also worth noting that, notwithstanding the confidentiality of Cabinet documents and documents received from Manitoba Hydro and the non-attributable basis of the Commission's interviews, the Commissioner received correspondence from former Premier Greg Selinger's legal counsel in late summer 2020 (almost two years after the Commission had been established), in which former Premier Selinger requested the ability to review all materials gathered by the Commission and to cross-examine other interviewees, as well as funding to do so. The Commissioner responded to Mr. Selinger's counsel that these requests were inconsistent with the process that the Commissioner had established for the inquiry, but that the Commissioner remained open to receiving any input from Mr. Selinger on the subject matter of the review. The Commissioner's legal counsel also confirmed to Mr. Selinger's counsel that the process established by the Commissioner was procedurally fair to all participants and consistent with the legal authority granted to the Commissioner by the mandating orders in council. While the Commissioner understands that former Premier Selinger disagrees with the Commissioner's decision not to permit him to review all materials gathered by the Commission, to cross-examine other interviewees, and to receive funding to do so, Mr. Selinger nonetheless provided a written submission to the Commission on the subject matter of the review. This submission contained valuable information and was given full consideration in the Commissioner's findings and recommendations.

What has become clear through this review is that all too often the otherwise thorough and insightful analysis, presentation, and decision-making functions for major capital projects proposed by Manitoba Hydro were constrained. These constraints influenced the path to a decision to the point where decisions became questions of "how can it continue?" rather than questions of "does this still make sense?". The constraints were put into place much earlier than one would expect and were supported throughout the past decade by action and sometimes inaction.

* Former Premier Greg Selinger provided a written submission to the Commissioner in place of an interview, without attribution. The Consumers' Association of Canada (Manitoba) participated in an interview and also provided a written submission, which they requested to be appended to this report (**Appendix B**). Some First Nations also opted to provide written responses without attribution.

The Commission has had the freedom to explore a broader decision-making space and with this extended scope has endeavored to explore the likely genesis for these projects.

We begin with a question of context:

What were the motivating goals that led to decisions that resulted in a $9.4 billion combined **generation** and transmission project becoming a $13.4 (8.7+4.7) billion project even as the reservoir at Keeyask was still uncharged as of the beginning of this review?

It is a vitally important question for the purposes of this review and recommendations.

Political Vision: The Genesis and the Problem

We are better served when our elected officials at every level have vision far beyond the near term or the essentiality of the current provision of the public goods and services. The vision of former Premier Gary Doer and the Government he led for Manitoba's hydro resources was clear:

> The government's plans for Hydro were developed before 2008, when the economic environment was different. At that time, premier Gary Doer said: "Hydroelectricity is Manitoba's oil".[1]

And then Premier Selinger in 2011:

> Hydro power is Manitoba's oil … The main economic question in this election is do we build Hydro or not?[2]

The Commissioner heard this vision repeated often at First Ministers Conferences and meetings of the Council of the Federation. These statements on a prima facie basis seemed to be reasonable given the prodigious hydroelectric resource in the Province and the movement towards lower emissions or emissions-free power.

However, those statements would have also highlighted a clear vision and policy direction to all who heard them, especially to those in Manitoba Hydro's offices.

Manitoba Hydro officials and board members heard them loud and clear and were confident that their efforts to advance new hydroelectric generation projects reflected the policy of the Government and that they were fulfilling the mandate given to them. This was confirmed in interviews during this review. There is every reason to believe that members of the Public Utilities Board ("PUB") were well aware of the clear vision statements of the Manitoba Government as well.

At that time the Government's vision resonated as not only bold and positive, but also plausible. Setting aside that the analogy of Manitoba's hydro resource to Alberta's fossil fuel endowment diverged greatly on the public sector role of the former. The concept of "Manitoba's Oil" is an analogy that must be limited in its application to the sale of power to external parties. In that respect, Manitoba's citizens, and not a private sector interest, bear the risk not only as involuntary venture capitalists for generation capacity for the export market, but also as customers (and payors) of last resort of the monopoly, Manitoba Hydro.

Still, there was, at the time, potential for a greater export opportunity.

1 The Western Producer, "Dam-nation: Why Man. plan is too costly," June 28, 2013 [Appendix A, Tab 1].
2 ChrisD, "Selinger: 'Hydro Power is Manitoba's Oil'," September 29, 2011 [Appendix A, Tab 2].

Existing climate change policies and rumours of enhanced climate change policies signaled during the term and Congress of the then Obama administration in the U.S. encouraged officials at Manitoba Hydro and provincial politicians alike.

Close attention was being paid to U.S. positioning away from coal and toward renewables for electrical generation. Premiers Doer and later Selinger were determined and effective in their tireless efforts to have hydroelectric power recognized as a renewable energy source. It seemed like an obvious designation but was more elusive than rationality would suggest and so their focus and determination were essential.

No doubt the energy policy direction and debate in the U.S. emboldened the Government of Manitoba in its belief that there was a bright future ahead for the export of clean Manitoba Hydroelectric power to the U.S.

But just as there were signals in the U.S. of this policy trend and related export possibilities, there were plenty of other signals from south of the border to the contrary:

> WASHINGTON (Reuters) — President Barack Obama's plan to use federal agencies, and the Environmental Protection Agency in particular, to drive his second-term climate change agenda might be in peril if he cannot fill vacant seats on the federal court that has jurisdiction over major national regulations, legal experts say.[3]

These signals were apparent by 2013 and fully materialized by 2016:

> WASHINGTON — In a major setback for President Obama's climate change agenda, the Supreme Court on Tuesday temporarily blocked the administration's effort to combat global warming by regulating emissions from coal-fired power plants.[4]

Commission interviews confirmed that signals like this dating all the way back to the beginning of the Obama administration were not resonating with Manitoba Hydro officials and Manitoba provincial politicians. At best it seemed as though the risk of policy change and the competitive energy option represented by natural gas were hypotheticals that they acknowledged when pressed to do so at the NFAT but were not considered material.

The knowledge that existed of a changing environment with respect to the impact of shale gas on the North American energy market were not reflected in public pronouncements by decision makers.

Politicians wanted this export story, the "hydro is our oil" story, to be true to provide continued justification for new hydroelectric projects and related developments even as costs grew rapidly. It was a signature economic development plan for Manitoba.

A complicating vulnerability of the plan for the Bipole III and Keeyask projects was inaccurately predicted domestic load growth. Vulnerability was exacerbated by the fact that the executed export contracts would not cover costs and future export contracts are extremely unpredictable as they are impacted by economic downturns, grid parity regarding U.S. renewables, the reality of U.S. federalism on Obama-era climate policies and the risk of a change in U.S. decision makers in the Congress and the Administration.

3 Reuters, "Analysis: Obama's climate agenda may face setbacks in federal court," March 24, 2013 [Appendix A, Tab 3].
4 New York Times, "Supreme Court Deals Blow to Obama's Efforts to Regulate Coal Emissions," February 9, 2016 [Appendix A, Tab 4].

The danger of even the most laudatory political vision is made manifest when it is not subject to critical, objective, and regular checks. It should be checked by a process that regularly updates assumptions upon which the project approval is based and provides off-ramps if deemed necessary by the consideration of new information.

While there may have been updates to the assumptions available to decision makers, there is little to suggest that they were considered. The $1.2 billion spent prior to approval to proceed with Keeyask suggests that pre-planned off-ramps or even rigorous evaluation of pre-approval spending of public dollars were not substantially in place. In fact, the Commission heard that Manitoba Hydro had learned the lessons of Wuskwatim and therefore the prebuild was done so that there would be no delay when the project was approved. This level of presumption at such a cost should be noted. The pre-approval spending, without objectively staged accountability, is something for which the elected Government and senior Manitoba Hydro officials of the day are accountable.

Early in the interview process the Commission heard that some senior Manitoba Hydro officials, who would have had direct access to decision makers, did not view Keeyask as needed in the near term.[5] Cabinet documents point clearly to Keeyask as effectively a merchant dam for export, not as a project needed to meet domestic power demand. As domestic demand forecasts have waned in recent years, the domestic need for Keeyask is even less certain.

And so, the effectively-communicated vision of the elected Government for Manitoba Hydroelectric possibilities while not in and of itself something to criticize, did drive the Bipole III and Keeyask projects forward even as costs rose and facts on the ground including export pricing forecasts softened. A political posture and mindset that may help explain a determination to proceed was displayed in the Legislative Chamber. When asked about Bipole III and Keeyask, both Premiers Doer and Selinger accused the Official Opposition of being eager to mothball major hydroelectric projects, while portraying their political party as the one with a pro-development vision when it came to the Province's hydroelectric resources. Indeed, Premier Doer nicknamed the Official Opposition the "mothball party of Manitoba."[6] This kind of positioning and rhetoric would not have made it any easier for the governing party to pause or stop the projects, even if they believed (or had reason to believe) that it was worth consideration.

No matter how commendable a vision from elected leaders may be, it can lead to negative unintended and lasting consequences if unchecked by changing assumptions and blinkered by confirmation bias and locked in by contract, policy, or government direction.

That is the genesis and subsequent problem for Bipole III and Keeyask. The domestic market for power in Manitoba through the application of Demand Side Management ("**DSM**"), disappearance of aspirational large industrial development, and flat growth has left Manitoba Hydro "power heavy" for at least the next 10 years. Bipole III and Keeyask must compete in the export market with new technology, a stable, low gas price alternative, and an uncertain political environment. There are firm contracts in place that provide some protection for the near term, but there is no guarantee that they will be renewed at the current prices or for an extended period of time. Domestic demand will likely grow to require the generation capacity eventually, but until that time these projects will be at the mercy of the international market. The implications of these significant capital investments and long-term risks now rest on the bottom of line of the Crown corporation, its customers and its shareholder, the Government of Manitoba.

5 Information received from participant, February 18, 2020.

6 Manitoba, Legislative Assembly, *Hansard*, 38th Leg., 4th Sess., Vol. 57, No. 55 (April 25, 2006) at 1620 [Appendix A, Tab 5]; Manitoba, Legislative Assembly, *Hansard*, 39th Leg., 1st Sess., Vol. 59, No. 10 (September 26, 2007) [Appendix A, Tab 6]; Manitoba, Legislative Assembly, *Hansard*, 40th Leg., 2nd Sess., Vol. 65, No. 10 (December 3, 2012) [Appendix A, Tab 7].

Executive Summary

> *"This lack of formal oversight by Government allowed the Bipole III and Keeyask projects to become firmly established and entrenched before they were subjected to independent review, at which point – given the sunk costs and executed agreements – they were effectively a fait accompli."*

INTRODUCTION

The history of hydroelectric generation project development in Manitoba is one marked by great success and sharp debate over timing, cost, impact on Indigenous groups, and politics. Projects associated with major infrastructure development often attract debate because of their large capital expenditure, the prospect of major benefits to the citizens, and the disruptive nature of the construction process itself. Many past major projects have been a boon to the Province from an economic development perspective, and many have been the focus of sharp debate and controversy. The Keeyask Generating Station and Bipole III transmission line and converter station project that this Commission was tasked with reviewing are the latest examples of this.

In the late 1970s, questions regarding the economy and efficiency of the Churchill River Diversion project and Lake Winnipeg Regulation project led to the creation of the Tritschler Commission to investigate decision making by Manitoba Hydro and adherence to its legislated mandate. The Commission was struck by the similarity of the issues identified by Justice Tritschler in 1979 and the findings of this Commission. The same themes of poor estimation, cost overrun, Government interference, and a myopic view of the generation landscape combined with a constrained decision space, appear in the Commission's review as they have in the past.

Does the nature of hydroelectric generation have inherent characteristics that cause these issues to recur? The current Canadian experience would suggest that this is so with recent reviews of the Muskrat Falls project in Newfoundland and Labrador and the Site C project in British Columbia echoing the findings of Tritschler and this Commission. Canada is not alone. The World Commission on Dams found in 2000:

> The decision to build a dam is influenced by many variables beyond immediate technical considerations. As a development choice, the selection of large dams often served as a focal point for the interests and aspirations of politicians, centralized government agencies, international aid donors and the dam-building industry, and did not provide for a comprehensive evaluation of available alternatives [7]

This is not to say that the goals of these projects were in any way baseless or less than laudatory in objective. Legitimate major infrastructure projects are opportunities to improve the life of citizens, a duty of government to pursue, and are a source of benefit and pride to a society. However, the landscape of mega-projects has often resulted in significant cost overruns, disappointing outcomes, and rancorous debate. Despite the soaring rhetoric, decision makers must step back and review the projects on an ongoing basis to ensure that the pitfalls of large project development are avoided.

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7 World Commission on Dams, "Dams and Development: A New Framework for Decision Making," December 2001, p. xxxviii [Appendix A, Tab 8].

Industry experts continue to call for caution and vigilance with respect to cost estimation and the use of modern techniques that, based on empirical research, can provide not only the tools but also the clear-eyed judgment of the actual potential cost of a project for decision makers to use in their deliberations regarding project approval.

The decision history of Bipole III and Keeyask exemplifies errors common to mega-projects around the world with optimism bias, estimating tunneling, and "locked in" decision making among the contributing factors.

From the genesis of the projects, the Commission saw optimism bias in early technology decisions such as the specification of a new converter technology for Bipole III which produced a significantly lower cost estimate that was subsequently abandoned when the bids were received and only the traditional technology was offered at a much higher cost. This bias was also seen in the quantification of potential benefits of Keeyask based on forecast domestic and export demand for electricity at high prices.

The Commission saw evidence of tunneling* that did not seriously consider sources of uncertainty outside of the proposed development plan itself. The falling price of natural gas, the cancellation possibility of major industrial projects, and the discounting of alternative generation options to meet domestic needs were examples of this tunneled thinking.

The most dramatic influence, however, came from the "locked in" nature and co-dependence of the two projects that are the subject of this review. Bipole III, as presented in its mega-project form beyond the simple backup transmission project became "locked in" in 2007 with the Government's decision to preclude an east side routing. Once this decision was made, Keeyask became not just possible, but fundamental to help justify the economics of the Bipole III project. In the same manner, Keeyask became "locked in" when the prospect of increased export demand became apparent and with government-approved export contracts in 2011 acknowledged that new hydroelectric power generation would be necessary to fulfill Manitoba Hydro's commitments under the contracts.[8]

From this point on, the construction of Bipole III and Keeyask were foregone conclusions notwithstanding the regulatory and review processes yet to occur. Professor Bent Flyvberg characterizes this "lock in" in his article, "What you Should know About Mega Projects and Why", as "leaving alternatives analysis weak or absent, and leading to escalated commitment in later stages."[9]

The review of Bipole III was constrained by not submitting the project to a separate NFAT process and specifically excluding it from the NFAT associated with Manitoba Hydro's Preferred Development Plan ("**PDP**"), which included Keeyask.

For Keeyask, the project was allowed to begin preparation with the approval of the Keeyask Infrastructure Project ("**KIP**") in 2012 in advance of both environmental approval of the dam and NFAT review of the project as a whole. Authorizing the spending of what would become $1.2 billion in "sunk costs" for the KIP influenced the later decision making of the PUB during the NFAT as the PUB recommended the project to the Government for approval notwithstanding a deteriorating estimate of benefits and strong suspicion of much higher costs.

Unfortunately, many of the concerns expressed by interveners during the NFAT and noted by the PUB

8 Order in Council 304/2011 [Appendix A, Tab 9].
9 Bent Flyvbjerg, "What You Should Know About Mega Projects and Why: An Overview" (2014) 45:2 Project Management, p. 8 [Appendix A, Tab 10].

* Tunneling is defined as "neglecting sources of uncertainty." John Hollman, "Estimate Accuracy: Dealing with Reality," 2012, p. 1 [Appendix A, Tab 11].

in its final report have become real and the additional generation capacity represented by Keeyask is now, and will be for many years, surplus to Manitoba's needs.

Throughout the time frame of 2011 to 2014, the Commission also heard evidence of a strong and active commitment by the Government to continuing the projects, which at times put it at odds with the Manitoba Hydro-Electric Board ("**MHEB**"). This commitment did not seem to carry over into oversight of the projects once they were approved.

Thus, the outcomes of the reviews of these projects that were conducted by Manitoba Hydro and government appear to have been in many ways locked in before they began. It can be argued that notwithstanding the earnest efforts of the regulator, the professional analysis of the project elements by PUB and intervener experts, and the passionate testimony given by witnesses during both the NFAT and the Clean Environment Commission ("**CEC**") hearings, the momentum provided by previous decisions and the agreements, promises, and expenses already committed, constrained the decision-making space to the extent that project approval was effectively a foregone conclusion.

Scholarly works in the field provide ample evidence of this well-trod path and offer advice on how to move forward on projects while ensuring the legitimacy of the base assumptions, guard against the most common pitfalls and help ensure that the outcomes of projects such as these meet the broad objectives against which they will be measured.

The findings of this report answer the specific questions posed in the Commission's Terms of Reference[10] and discrete recommendations are offered for the narrow topics examined. However, it has become clear from the efforts of this review that the forces in play that led to the development of Bipole III and Keeyask are much more systemic and are a reflection of the magnitude of the projects and the potential positive impact of their completion. This led decision makers to commit to an outcome far too early in the process without due consideration to the complexities and risk inherent in projects of this scope and size. When the inevitable realities began to appear as the projects progressed, the decision makers could see no way out and were forced to defend escalating costs, slipping timetables, and eroding financial benefits. This can lead, and in this case certainly led, to narrow, incremental decisions rather than a step back to look at the project holistically and with a firm resolve to ensuring that proceeding remained in the public's interest.

Projects do reach a point of no return and the Boston Consulting Group ("**BCG**") review of Keeyask prepared for Manitoba Hydro in 2016 correctly identified the paths available to the company and the Government at that time. In the BCG review, the tally of sunk costs had reached a point where stopping the project would cost almost as much as finishing it. Thus, the final constraint had been applied to the decision making leaving only mitigation of further risk (which the Commission notes was accomplished with skill, as from that point forward there were no material changes in project scope or cost).

It is useful to note that the motivations of all the actors in this exercise were based upon what they thought was best. Manitoba Hydro's grid was at risk due to the proximity of the two existing Bipole lines and some form of redundancy was required. Manitoba Hydro had also identified an opportunity to increase export revenue from the MISO market and create deeper ties to a market that was (and is) facing a transition from coal generation to meet its power needs.[11] The Government of Manitoba was committed to continuing to move away from thermal power generation, expanding the benefits to Indigenous groups and securing international recognition of their environmental protection bona fides through the garnering of a UNESCO World Heritage Site designation. The Government also viewed

10 Order in Council 301/2018 [Appendix A, Tab 12].
11 2017/18 GRA, Exhibit DEA-1, p. 16 [Appendix A, Tab 13].

the Province's abundant hydroelectric resource as an opportunity to create long-term wealth for the Province. The PUB was similarly faced with deciding between a "need" based path forward or one based on "opportunity" with the clear goal of providing the best result for Manitoba ratepayers. While all laudable perspectives, hindsight has shown that these views led to shortcomings in the review and execution of Bipole III and Keeyask that have resulted in Manitoba Hydro ratepayers and Manitoba taxpayers assuming material long-term costs and risks that may ultimately not be in their best interests.

This review has operated on two levels. At one level it is a review of these mega-projects with an oft repeated tale of government vision, market realities, and project management with the frequently seen result of late delivery and significant cost overruns.

At another level it deals with the structure of Manitoba Hydro as a public utility and a commercial enterprise with respect to responsibility and accountability and the importance of energy policy when major provincial economic drivers are at risk.

This executive summary has three sections. Section 1 deals with the specific questions noted in the Terms of Reference regarding the design, review, and execution of the Bipole III and Keeyask projects (Chapters 1 and 3-5 in the body of the report). Within this context the Commissioner makes many findings and recommendations associated with the projects themselves. Section 2 of the summary deals specifically with the actions of the Government in the lead up to the NFAT and how the process was thwarted as vision outran reality (Chapter 2 of the report). Section 3 of the summary talks about the future (Chapter 6 of the report). It discusses the nature of the combined public utility/commercial venture model and offers recommendations on the allocation of accountability, a practical process for Manitoba Hydro to strengthen its financial structure to provide stability for its shareholder, and a discussion of the challenges facing the utility in the future and how the Government should prepare for this uncertain future.

SECTION 1: REVIEW OF BIPOLE III AND KEEYASK PROJECTS

The technical aspects of these projects have been well examined – over $50 million spent in approval, review, and recovery studies. Experts, analysis, professionals, tens of thousands of pages of reports, rebuttal, and testimony have been created in the formal proceedings performed by the PUB and attendant experts. The Government has proposed new legislation in **Bill 35** that would require better planning processes for Manitoba Hydro, fixed performance targets for the utility, a modified rate setting process, and formulaic limits to rate increases, in part due to the Province's experiences with Bipole III and Keeyask.

This summary will highlight what the Commission considers to be the most relevant findings and recommendations with respect to these projects in the context of the Terms of Reference.

Were the Projects Necessary?

Bipole III

The need for Bipole III is a two-part question. The first element is the identification of the need for more reliability in the transmission system based upon the risk of catastrophic failure of either Bipole I and II or the Dorsey Converter Station. The risk was real but hardly new. The need for physical separation was identified as early as 1975 when it was recommended that when Bipole III was constructed it be sited to provide physical distance from the other Bipole lines to minimize the risk of simultaneous failure. Weather events in the 1990s and 2000s drew attention to the risk and a solution was sought to mitigate it. The motivation of Manitoba Hydro was noble in seeking a more robust transmission system, but the long-term knowledge of this need for reliability indicates that it was not considered to be required on an emergency basis nor was the only possible solution a mirror system of the current Bipole transmission lines complete with converter stations. This leads to the second part of the question which revolves around whether this version of the project was needed at the time of decision.

The decades long delay in embarking on a reliability project left the Commission searching for another motivation for the project as ultimately designed. The prospect of significantly increased generation, primarily for export, supplied that motivation. A decade of development with the construction of two major hydroelectric dams could only occur if the transmission system was enhanced to carry the new power. The timing of this generation was inextricably tied to new export contracts and this new generation provided both the time window for the construction of Bipole III and also determined the scope of the project with the addition of converters to the original scope to support new generation.

The Commissioner does not believe that Bipole III was built solely for reliability. If that were the primary motivation it would have been built years earlier. Rather, Bipole III was built to facilitate the construction of new electrical generation which logically makes the timing of Bipole III almost completely dependent on the timing of Keeyask. By focusing attention on the reliability element, this project was separated from the approval process normally associated with projects of this size and its need and cost were disaggregated from the analysis of Keeyask during the NFAT. Bipole III did improve the reliability of the Province's electrical grid, but its construction and **in-service date** were driven by the desire to build new generation.

Keeyask

The question of whether Keeyask was necessary, particularly whether it was necessary to meet the Province's anticipated electrical needs at the time of the NFAT, was a specific focus of the NFAT. The export contracts were in place for much of the firm power, but the issue of when Manitobans would require the power was in question. The load forecast was evaluated by expert witnesses of the PUB as well as interveners such as the Consumers' Association of Canada (Manitoba), the Green Action Centre, and the Manitoba Industrial Power Users Group.

In the absence of a detailed Integrated Resource Plan ("**IRP**"), Manitoba Hydro used its load forecast as the starting point for the determination of future power need.

The PUB had questioned the accuracy of Manitoba Hydro's load forecasts in the past[12] and its experts in the NFAT weighed in saying that it would expect "a more robust forecast to better understand the factors that influence short-term fluctuations."[13]

The forecasting methodology was debated vigorously during the NFAT and while PUB experts ultimately agreed with Manitoba Hydro's forecast, they included a caveat regarding structural change in the future that could leave assets "stranded."[14]

Manitoba Hydro's rationale for new generation was based on its 2012 Electrical Load Forecast that expected Gross Firm Energy to grow at a rate of 1.5% per year for the forecast period of 20 years and Gross Total Peak requirements to grow by the same percentage. This forecast, which underpinned the original application to the NFAT, was updated during the proceedings to include the impact of a more aggressive DSM plan. The application of DSM to the load forecast had material impact on the need for dependable energy and moved the need date for dependable energy out eight years from 2023 to 2031.

12 PUB Order No. 99/11, p. 52 [Appendix A, Tab 14].
13 PUB, Report on the NFAT ("**NFAT Report**"), June 2014, p. 71 [Appendix A, Tab 15].
14 NFAT, Exhibit ERA-5, pp. 6, 19 [Appendix A, Tab 16].

As the opportunities for DSM became manifest, the load forecast presented by Manitoba Hydro as the domestic demand need basis for its application was weakened.

Commensurate with the presentation of the impact of DSM on the need date for new resources, new potential demand was identified that would mitigate against the possible delay in need for new resources. The prospect of a 1700 GWh increase in demand due to new pipeline load dragged the need date forward to 2024. Timing is interesting here because the pipeline demand delivered with the updated information in March 2014 only survived until August of that year (two months after the NFAT Report) with the release of the Manitoba Hydro 2014 Electric Load Forecast that reduced the forecast pipeline demand by 60%. This reduction alone would have extended the need date by more than four years. It is notable that forecast pipeline demand, so important to the justification of Keeyask's domestic need, could vary by 60% within just two months of the conclusion of the NFAT. It is also of note that the 2014 Electric Load Forecast wherein this reduction was noted was being developed during the time of the NFAT and the new information that ultimately changed the 2014 forecast was not made available to the NFAT Panel.

This element of changed domestic demand had significant impact on the planned need date for new generation and on the conclusion that the PUB reached in June 2014 to recommend the project. Despite the material change in this core assumption within months of the NFAT Report's release, there was no reconsideration or revisiting of the need for or the timing of Keeyask by Manitoba Hydro, the MHEB, the PUB or the provincial Government.

It is unusual for generation to be built on the prospect of speculative future industrial demand. Manitoba Hydro had seen large industrial load come and go (most recently with the shutdown of the Vale smelter in Thompson) and to justify a need date on the basis of a prospective load makes a poor case for major investment.

In its 2017/18 General Rate Application ("**GRA**"), Manitoba Hydro referenced the cancellation of projects in the petro/oil/natural gas sector and, combined with 1.5% DSM, forecast 10 years of no net load growth. In this application, the CEO of Manitoba Hydro described the previous plans as "not adequate and far too risky," that the "MH business outlook has deteriorated significantly," and that "the old financial plan has **failed**"[15] (emphasis in original). <u>These dramatic statements were made only 30 months after those same financial plans underpinned a 78-year financial justification for Keeyask</u>.

It is the Commissioner's finding that Keeyask was not necessary at the time of the NFAT to meet the Province's then-anticipated electrical needs in a timely and cost-effective manner. The pipeline demand that drove the need date was prospective at best and was officially reduced within 60 days of the end of the NFAT.

The decision to proceed with Keeyask was driven by momentum from previous decisions including reputational risk from export agreements that <u>required</u> new generation when that generation had not been approved, "sunk costs" of $1.2 billion in infrastructure spending to support the project, and partnership agreements that had already been executed with First Nations after significant effort and good faith on their part. These prior decisions effectively pre-determined that Keeyask would proceed even though that was not the lowest cost option to meet domestic need at the time of the NFAT.

15 2017/18 GRA, Exhibit MH-64, p. 3 [Appendix A, Tab 17].

Net Benefits and Best Practice

Keeyask

A series of metrics were used to assist the economic analysis of Keeyask during the NFAT: net present value ("**NPV**"), cumulative present value ("**CPV**"), break even/payback, internal rate of return ("**IRR**"), and expected value.

To perform the analysis, Manitoba Hydro prepared a series of alternative development plans and compared the net benefits to an All-Gas Plan (Plan 1).

The inputs used for this analysis included the forecast development costs of the various options and the revenue earned by each scenario over a 78-year time horizon determined by Manitoba Hydro to be the useful life of the hydroelectric generation under consideration.

The use of NPV is an industry standard measure and is a best practice for economic evaluation. However, as with all calculations, the outputs are only as good as the inputs; the assumptions used in developing the inputs can have substantial impact on the outputs from the model. A case in point: the NPV analysis of the PDP first submitted with the NFAT application showed the PDP with the highest NPV compared to the alternative plans with some $1.7 billion of benefit over the 78-year life of the plan. Updated information provided to the PUB regarding increased capital cost estimates, increased investment in the transmission intertie, and increased DSM were used to recalculate the NPV and the impact was profound. Under the new assumptions, the NPV of the PDP was reduced to just $45 million over the 78-year horizon, a 97% reduction.

The best practice of NPV calculation stands on its assumptions and, one hopes, the assumptions remain consistent as comparative calculations are made.

There is no question that NPV provides a time-adjusted valuation of future cash flows and is a powerful tool to analyze comparative investment decisions. However, many of the experts during the NFAT took issue with the parameters used in the formula. First is the 78-year time horizon for the calculation. The future is uncertain and the further out one looks the less certain one can be. Manitoba Hydro chose to use the useful life of the hydro-generation projects as its time horizon, but it only performed detailed forecasts for the first 35 years, extrapolating those results for the remaining 43 years. Mathematically this is defendable, but the break-even dates (the date when the cumulative NPV or CPV equals the All-Gas Plan) for the projects all occurred beyond the 35-year detailed forecast (2050 or later). Manitoba Hydro vigorously defended its financial analysis methodology[16] in its final argument and while the experts agreed that the tool was the "gold standard," Manitoba Hydro's outputs relied on the assumption that anticipated revenue would remain constant over the final 43 years of the forecast. Morrison Park Advisors Inc. ("**MPA**") and La Capra Associates Inc. ("**LCA**"), independent experts retained by the NFAT Panel, both pointed to the uncertainty and unpredictability associated with such assumptions over a 78-year time frame.

To incorporate some treatment of risk in the NPV analysis, Manitoba Hydro added a range for three key variables (fuel prices, discount rates, and energy prices) and for each variable assigned a low, reference and high range percentage difference. It then performed calculations based on the weighted values in a probabilistic analysis to determine "Expected Net Present Value." There was general agreement that this calculation was an important risk analysis tool with which to evaluate the various development options. When weighted risk was included in the calculation, the Expected NPV of the PDP was lower than its NPV and the impact of potential futures was revealed. However, Manitoba Hydro was only

16 NFAT, Exhibit MH-204, Manitoba Hydro Final Argument, pp. 140-143 [Appendix A, Tab 18].

able to provide a partial update of Expected NPVs when new information was made available in March 2014 and this partial update did not account for DSM.[17] The PUB deemed it "unfortunate" that this left it "without one of the important decision making tools at its disposal."[18]

The NFAT was characterized by a significant number of changes to underlying assumptions as the hearings proceeded. New capital cost estimates, the revelation of significant opportunity in DSM, the abandonment of prospective investment by third parties in the intertie, significant potential demand from pipelines, and a more sophisticated economic evaluation tool all became manifest during the proceedings. One can only imagine the difficulty that the NFAT Panel had in keeping the various versions of the plans straight while Manitoba Hydro tried to update the analysis and return new versions of their development plans to the NFAT Panel. The Commission's review of the NFAT proceedings leads it to question the lack of flexibility in terms of time for the PUB to complete the hearings and provide its report to Government. The Commission heard during interviews that the PUB was severely stressed to complete its work within the time frame provided by the NFAT Terms of Reference, which is not surprising given the significant changes in the underlying assumptions to Manitoba Hydro's application and the lack of complete updates to the evidence based on these changes. The NFAT Panel was time constrained in their deliberations and appeared to have had no ability to request an extension. Manitoba Hydro was requesting that the Government intervene to reduce the scope of questions being asked, noting that construction was scheduled to start in August 2014.[19] Notwithstanding these pressures, however (which were based on construction plans for a project that was as yet <u>not</u> approved), an extension of just two months would have uncovered the weaknesses in the prospective pipeline demand and allowed the PUB to use the risk adjusted Expected NPVs to better understand the economics of the various alternatives. This would have been best practice.

In sum, Manitoba Hydro used best practice tools in its estimation of the net benefits of Keeyask, but the quality of the input variables was poor through the NFAT as evidenced by the material changes to the underlying assumptions throughout the NFAT process. The selection of very long-term parameters for the calculation without due consideration of the uncertainty of future projections rendered the results inherently unreliable. The NFAT was concluded on its original schedule notwithstanding the introduction of new information that could not be evaluated within the NFAT Panel's mandated time frame. <u>The PUB should have sought an extension to allow for completion of the economic analysis</u>. Similarly, all parties should have paused to reconsider the NFAT findings when the key underlying assumptions for those findings changed so quickly after the NFAT report was released.

Bipole III

The net benefits for Bipole III were described by Manitoba Hydro to the PUB in various GRAs and were first mentioned in Manitoba Hydro's 2009 capital expenditure forecast ("**CEF**") as part of the upcoming decade's development plans. In that CEF, Manitoba Hydro described the benefits of Bipole III as follows:

> Provides increased reliability to the Manitoba Hydro system due to the critical risk to the Province and the Corporation of not mitigating an Interlake (Bipole 1 and 2) corridor outage or a Dorsey station common mode outage. In normal steady state operation, it will also provide an increase in southern power at full load, due to decreased line losses (approximately 78 MW).[20]

17 NFAT Report, p. 161 [Appendix A, Tab 15].
18 NFAT Report, p. 161 [Appendix A, Tab 15].
19 Briefing Note, Department of Energy, "Addressing Timing Concerns with the Needs For and Alternatives To Review Currently Being Conducted by Manitoba Public Utilities Board," November 27, 2013.
20 Manitoba Hydro, Capital Expenditure Forecast (CEF09), November 2009, p. 12 [Appendix A, Tab 19].

The most effort in describing the net benefits of Bipole III occurred during Manitoba Clean Environment Commission's review of the project in 2011 and 2012. In its final argument, Manitoba Hydro described the project as "the best solution to improve reliability of the Manitoba Hydro system and the security of electricity supply."[21] Manitoba Hydro supported this statement with its expertise and experience in constructing, operating and maintaining over 18,000 kilometres of Alternating Current (AC) transmission lines and over 1800 kilometres of Direct Current (DC) transmission lines over the past 60 years, as well as the construction and operation of three converter stations.[22]

From a net benefit perspective, the decision to route Bipole III on the west side of the Province did not follow best practice as it was clear from early planning by Manitoba Hydro and confirmed by former executives that the eastern route was preferred because of its shorter length, lower cost and a more significant reduction in transmission losses associated with the line.

While the Commission could find no evidence that a formal net benefit calculation was performed, the Government determined that the environmental benefits of avoiding the boreal forest on the east side of Lake Winnipeg to support a UNESCO World Heritage Site application coupled with what was reported to be rejection of an eastern alignment for Bipole III by Indigenous groups, made the western route more attractive. The Commission could find no evidence that UNESCO at that time would decline the World Heritage Site application if there was a transmission line on the east side of Lake Winnipeg. Moreover, support from Indigenous groups for an east side route may have been achieved if partnership was offered to those groups. There was a relatively weak effort to mitigate the concerns of Indigenous groups, as the eastern route was eventually precluded by government direction.

In sum, even though Bipole III did not undergo a public vetting of its net benefits, the engineering conclusion that the eastern route was the most economical and technically superior option for the project was overturned by the Government who determined that the net benefits of Bipole III were maximized by a western routing. An estimated incremental cost of $400 million was known at the time of the CEC hearings, but the Government believed that the value of a prospective UNESCO World Heritage Site and a smoother negotiation path with affected Indigenous groups justified the incremental cost. This decision was made without any independent review or quantitative assessment, contrary to best practice. As noted in the body of this report, the incremental costs of routing Bipole III on the west side of Lake Winnipeg may have been closer to $1 billion.

Soundness of Export Market Forecasts

Export market forecasts were integral to the analysis of Keeyask and Manitoba Hydro sought the input of six different consultants to provide a forecast of opportunity pricing in the coming years and then averaged their forecasts to provide this input. This is a standard approach to modelling and attempts to derive decision input from an uncertain future. Experts noted the uncertainty in the average forecast, but thought at the time that the plans were less sensitive to opportunity pricing.

The PUB was very diligent in its review of the export market forecasts provided by Manitoba Hydro and while it noted the impact of variance in carbon pricing and was suspect of Manitoba Hydro's claim that it could sell all of its surplus dependable energy under long-term firm contracts with premium pricing, it concluded that the risk was acceptable since the generation capacity of Keeyask would be required for domestic use prior to the end of the firm contracts in place.

21 Manitoba Hydro, Bipole III Transmission Line Project Environmental Impact Statement, Final Argument, p. 2 [Appendix A, Tab 20].
22 Manitoba Hydro, Bipole III Transmission Line Project Environmental Impact Statement, Final Argument, p. 2 [Appendix A, Tab 20].

This was a reasonable conclusion based on the assumption at the time that the growth in domestic demand would remove the long-term risk associated with export markets. As noted above, however, the forecast need date for new generation to meet incremental domestic demand was pushed out by many years within months of the NFAT review.

Manitoba Hydro's reliance on export demand to support Keeyask while also seeking to reduce domestic demand through DSM created a consequential relationship that on one hand suppressed domestic demand by introducing strong DSM measures which would increase the power available for export, while on the other hand exposing ratepayers to potentially higher rate increases if the revenue from exports fell. MPA determined that the ratepayer costs in all of the assessed development plans were inversely proportional to energy prices, and likely quite strongly inversely proportional.[23] This magnified risk to ratepayers made export pricing critical to the economic analysis of the development plan.

Notwithstanding the many expert reviews, sharp debate, and confident defence of the market forecasts in the NFAT, the estimates of export revenues underpinning a 78-year economic plan lasted just 3.5 years before they were deemed a failure.[24] Manitoba Hydro had argued in its 2013 GRA that its long-term export contracts would have a price premium associated with the environmentally friendly nature of hydroelectric power, price certainty from a fixed contract price and stability of supply. In the 2017/18 GRA, this was removed from its price forecast with an attendant lower revenue forecast.

The prospect of relatively imminent domestic demand gave the PUB confidence that there was a "safety net" for the Manitoba Hydro forecasts should export revenue be lower than expected. The statements of the CEO shortly after the NFAT indicated that this safety net had been removed or at least delayed many years into an uncertain future. As a result, ratepayers will be bearing the long-term risk that Keeyask will not generate sufficient export revenue to cover its costs and that the project will not be needed for domestic demand for many years to come.

The Assessment of Commercial Risk

Manitoba Hydro's risk management in the Bipole III and Keeyask projects was characterized by detailed analysis of individual, discrete risks and Manitoba Hydro attempted to mitigate those risks throughout the projects. However, there was no consideration of compound risk – the combination of two or more related risks. This approach is consistent with much of what the Commission has seen from the delivery of these projects where decision makers often could not see the forest for the trees. BCG flagged this in their 2016 report where they indicated:

- The current project planning approach is iterative, instead of being consolidated in an upfront manner [Exhibit 24].
- This limits insight into the compounded execution and financial risks from running several major, simultaneous projects concurrently, even when they have clear interdependencies as is the case with Bipole III, Keeyask, and the tie-line.
- A more consolidated planning approach with respect to major projects – one that takes into account the combined opportunities and risks for the company and its stakeholders – would be more appropriate to implement.[25]

23 NFAT, Exhibit MPA-3-1, p. 22 [Appendix A, Tab 21].
24 2017/18 GRA, Exhibit MH-64, p. 3 [Appendix A, Tab 17].
25 BCG, "Review of Bipole III, Keeyask and Tie-Line Project," September 19, 2016, p. 6 [Appendix A, Tab 22].

Keeyask

Some of the many reviews of the Keeyask project rightly note that Manitoba Hydro took on significantly more risk by the use of a cost reimbursable contract structure in the general civil contract ("**GCC**") as opposed to a different form of contract that would have placed project execution risks on the contractor. The Commission heard that the contract style was a matter of discussion between Manitoba Hydro and several contractors who were asked about their preferred type of contract. The argument from Hydro executives is that they were concerned about receiving bids that were very high to reflect the uncertainty of some elements of the project. The contractors provided a solution – a cost reimbursable contract that effectively transferred the risk to Manitoba Hydro. This solicitation of contract preference is not normal practice and produced a predictable advantageous result for the contractors.

By entering into a cost reimbursable contract, Manitoba Hydro transferred most of the project execution risks to itself. When the contractor fell behind in its concrete placement timetable and the project was delayed, a re-negotiated contract and incremental budget was needed to complete the project.

During the NFAT, Manitoba Hydro believed that it had reduced risk by negotiating a cost reimbursable contract, as evidenced by a reduction in the percentage impact of "high capital costs" from 30% to 20% for its probabilistic NPV calculations.[26] This led the Commission to question whether Manitoba Hydro understood the significant risks inherent in this type of contract.

Risk management requires not only the gathering of market quotations on products and services associated with a project, but also a realistic inclusion of reserves to deal with unidentified but inevitable cost escalation depending on the stage of the project. The cost estimate used in financial analysis depends on this input and the ultimate approval of a project. The estimates presented during the NFAT for Keeyask did not include sufficient reserve to reflect the underlying risk of the project. The NFAT Panel was uncomfortable with the reference estimate of $6.5 billion and noted that the construction cost would likely be closer to the high range of $7.2 billion. An independent expert, Knight Piesold, flagged the potential for an even higher cost and suggested that rather than the industry standard P50 cost estimate, a more risk averse decision maker would use a P80 cost estimate[27] and a higher escalation rate. Manitoba Hydro estimated that these changes would increase the estimate by over $320 million. The current cost estimate for Keeyask is even higher than these numbers.

Construction risk was understood to exist with divergent views as to how large the contingency should be, but with the perceived protection of the cost reimbursable GCC, Manitoba Hydro pressed ahead. This decision was contrary to best practices and ultimately contributed to the cost overruns experienced to date for Keeyask.

Bipole III

Bipole III followed a somewhat different path. During the NFAT, estimates of the cost of Bipole III were reported to be $3.28 billion based on a 2011 approved budget. This estimate was updated to the MHEB in August 2014, increasing the budget by $1.37 billion to $4.65 billion. So, two months after the NFAT approval, the cost of Bipole III was escalated by 41%. This new estimate has a disturbing history. Internal Manitoba Hydro documents show that a 2010 capital project justification ("**CPJ**") for Bipole III was presented to management with an estimated cost of $4.1 billion. This estimate was not approved and thus was not included in the integrated financial forecast ("**IFF**"). A consultant was retained

26 NFAT Report, p. 149 [Appendix A, Tab 15].
27 NFAT, Information Request (IR) KP/MH II-26a [Appendix A, Tab 23].

to review this $4.1 billion estimate and several changes were made that reduced the estimate to $3.28 billion. This was presented to management and subsequently to the MHEB in 2011 and became the public estimate for the project.[28]

In 2014, a detailed re-estimate of Bipole III costs was conducted incorporating updated pricing and contracts. This review resulted in a new $4.65 billion cost estimate. The presentation to the MHEB describes "$485.5 million removed from contingency & management reserve to obtain 2011 approved estimate."[29] While the initial estimate was conducted by Manitoba Hydro early in the planning stages for Bipole III, it appears that the initial estimators had a better sense of the potential cost of the project and included an appropriate reserve to deal with scope changes and the unforeseen. Management would not approve the project at that cost so an exercise was undertaken to provide a more acceptable estimate that would be approved. However, the $3.28 billion estimate was proven to be unrealistically low and this was only uncovered in 2014 after the project was approved. These material changes and manipulations to the Bipole III cost estimates demonstrate the need for independent reviews for projects of such a large scale.

The PUB has found in subsequent GRAs that, during the NFAT, Manitoba Hydro was in a position to know that the costs of Bipole III were significantly higher. Nevertheless, the lower cost was included in all their financial forecasts leading to an incomplete analysis of the impact of the overall development plan on the financial structure of Manitoba Hydro.

The exclusion of Bipole III from the NFAT precluded an investigation of the cost structure presented by Manitoba Hydro and led to a material underestimation of the financial implications of the projects in the NFAT analysis.

Post-Approval Oversight

The Keeyask project was executed after the completion of the Wuskwatim Generating Station project near Thompson. While a smaller endeavor, Wuskwatim was delivered significantly over budget and has not met its goals as presented to the PUB. Manitoba Hydro identified lessons learned from the Wuskwatim experience as follows:

> The contract model has to fit the circumstances and market conditions. Goals and incentives must be mutual and tied to project critical success factors. Independent third-party reviews are beneficial, providing independent perspective on the projects and processes enhances the opportunity for continuous improvement. Rigorous oversight is essential. Project integration is critical to success. Manitoba Hydro has to be active in managing the interface points between contracted work packages, and doing things as they have always been done does not work for complex projects that require constant innovation and a culture of collaboration.[30]

However, the record shows that Manitoba Hydro did not learn the lessons noted or at least did not incorporate them into their practice. The contract model, level of oversight, and level of active management were examples of recurring issues in the Keeyask project that had been identified as contributors to the difficulties associated with Wuskwatim.

A 2012 Stantec report to Manitoba Hydro found that cost management was not sufficiently addressed in Manitoba Hydro's New Generation Construction Division's procedures. Stantec noted that there should be a strong culture of cost tracking throughout the project, including during the execution

28 Manitoba Hydro, "Review of Bipole III Cost Estimate," Presentation to the MHEB, August 2014.
29 Manitoba Hydro, "Review of Bipole III Cost Estimate," Presentation to the MHEB, August 2014.
30 2017/18 GRA, Transcript, p. 5552 [Appendix A, Tab 24].

phase. However, notwithstanding the Stantec report's warning of internal capacity challenges, the project proceeded and by 2016 a KPMG review similarly found that cost control procedures were not sufficiently robust and should be improved. The PUB determined that there was no effective oversight of the cost reimbursable GCC by Manitoba Hydro and it was not until 2016 that external expertise was sought to exert control over the rising costs.

Pursuant to the recommendations of a series of external consultants, Manitoba Hydro began to exert significantly more oversight over the general contractor and the project as a whole in 2017. At that time, the GCC was renegotiated and the total project cost estimate increased to $8.7 billion, which has remained the estimate since.

Manitoba Hydro had early warnings of its cost control challenges from Stantec in 2012 and many lessons learned from the Wuskwatim project but did not seem to apply these to the early stages of Keeyask. Trusting in the cost reimbursable nature of the GCC provisions, Manitoba Hydro did not exercise appropriate oversight post project launch and significant cost overruns were experienced, mostly to the account of Manitoba Hydro due to the nature of the cost reimbursable contract.

Management capacity within Manitoba Hydro was strained by the concurrent development of two mega-projects. Former Manitoba Hydro executives described the situation as "overwhelming" and that better oversight would have occurred if only one project was ongoing rather than two. The Commission also heard that by the time Keeyask and Bipole III were approved, the experienced "project guys" had retired and nobody in the Generation unit of Manitoba Hydro had done a major project before. At the time of preparation for the NFAT it is notable that Manitoba Hydro had undergone a leadership change and it is possible that the new CEO was not aware that most of the experienced project people had retired. The Commission did not find evidence that this issue was on the radar of management or the MHEB during the planning, approval, or early stages of the Keeyask project.

Prior to 2016, Manitoba Hydro used a Major Capital Projects Business Unit with dedicated senior management for major projects. This structure was changed in 2016 and replaced with a Major Projects Executive Committee ("**MPEC**") composed of the President and CEO and five vice-presidents with accountability for the execution of the major capital projects. This reorganization and mostly senior management focus contributed to the better execution of the projects once it was established.

Risk Mitigation and Changing Circumstances

Keeyask

There has been much discussion regarding "stage gate" approval processes and "off-ramps" for major projects to react to significant changes in circumstances. Keeyask had one of these opportunities described in the Joint Keeyask Development Agreement ("**JKDA**") that allowed for cancellation of the project before the first pouring of the concrete. When this option was reviewed in 2015 by the new CEO of Manitoba Hydro it was determined that this was impractical because of the level of investment to date and the proximity of the date for first pouring of the concrete. This is the only documented point at which Manitoba Hydro considered whether to stop the project.

It is recommended that major capital projects establish clear decision points where assumptions are re-tested and re-affirmed and that the decision points be determined such that actual opportunities to stop the project exist. It is understood that there will be a point when a project cannot be reasonably stopped which speaks to identification of these key decision points when options still exist. At these points the project should have to update its underlying assumptions and demonstrate that it remains prudent to proceed over alternatives. If changed circumstances undermine the rationale for project, decision makers must have the resolve to change the project or abandon it if required.

Bipole III

The Bipole III project is a different story. Once the estimate for the project was updated to include reasonable management reserves and recent cost and scope estimates, the **control budget** for the project remained within generally expected boundaries. Escalation was experienced but external reviews generally found that the project was managed professionally and within accepted parameters. It is important to note that more traditional contract structures were used for Bipole III and that Manitoba Hydro had significant in-house experience with the construction of transmission projects, in contrast to its lack of recent experience in large-scale generation projects.

Government Processes

The Commission is not aware of any post-approval oversight process undertaken by the former Government that mitigated the risk associated with Keeyask or Bipole III or that accommodated changing circumstances as they occurred.

Former Manitoba Hydro executives and former Government personnel told the Commission that discussions with the Government were only on the matter of electricity rates and there was no opening for a discussion of the projects. A review of Cabinet material from 2014 to 2016 as Keeyask ran into its difficulties show no items where the progress of the projects was reviewed or discussed.

Government cannot abjure its responsibility for major capital projects given their impact on the Government's financial framework and their long-term impact on citizens as the ultimate payer of deficiencies through utility rates and taxes. Government involvement does not end at the approval stage. Ministers are responsible for their portfolios and ministers responsible for Crown corporations are no different. It is not recommended that ministers involve themselves in the operational aspects of Crown corporations, but in the event of major capital expenditure using borrowed money guaranteed by the Province, the Minister on behalf of the Government must be actively aware of the progression of the projects and report regularly to Cabinet and the Legislature on the state of these major endeavours.

SECTION 2: GOVERNMENT DIRECTION

The Commission's review of government direction to Manitoba Hydro identifies objective actions that influenced development of the Bipole III and Keeyask projects, such as the written instruction to the MHEB precluding the eastern route of Bipole III and the impact it had on the cost and following project decisions. However, it is clear that government action had effects far beyond the specific routing direction for Bipole III. The policies of the Government and the political rhetoric associated with these policies provided clear and consistent direction to Manitoba Hydro that encouraged the expansion of the export market from a profitable option for surplus power to a tool of economic development as the producer of "Manitoba's oil." Manitoba had benefitted from the electricity export market for many years and in the previous decade had seen spectacular earnings from the U.S. market for excess power from the Limestone Generating Station. Government was clearly delighted with this and began to speak of this opportunity as being akin to the oil resources of Alberta and the great benefits garnered from the development of that natural resource.

Manitoba Hydro heard clearly the clarion call from its owner and responded with a decade of development plans centred on the creation of new power plants on the Nelson River, all of which could serve the U.S. export market. With this backdrop it is unlikely that Manitoba Hydro would seriously consider thermal power generation (natural gas) as an option to present to the Government and while the All-Gas option was presented as the base case for the NFAT, both the PUB and intervener experts indicated that the base case was flawed in its composition and not a fair comparator to the various pathways presented by Manitoba Hydro. This is completely understandable given the political environment of the times.

Further direction was given in the 2012 Clean Energy Strategy where Keeyask, Conawapa, and Bipole III were specifically mentioned as priority actions. It is appropriate and helpful for the Government to provide direction to its Crown corporations in matters of policy, but it should not pre-determine what projects should proceed before they are fully vetted. The Clean Energy Strategy provided no doubt that the Government was fully in support of the Bipole III and Keeyask projects before they were approved.

The Commissioner recommends that the Government move quickly to develop a new comprehensive energy strategy for the Province. Rapidly changing technology, macro-economic and political influences and the capital heavy nature of the Manitoba system require a strategy that recognizes the economic, environmental, and societal impact of the electrical system and provides the input Manitoba Hydro needs to serve the citizens and ratepayers of the Province. This strategy should be crafted with the input of all stakeholders in a public and formal manner to produce a policy that will inform the Manitoba Hydro Integrated Electricity Resource Plan. This would provide Manitobans with a clear picture of how their electricity needs will be met and enable them to understand the investments that will be made on their behalf. Again, however, such a policy should not pre-determine what projects or types of projects should proceed.

The Government also restricted Manitoba Hydro's planning by constraining its operational and planning space. Project Labour Agreements preclude Manitoba Hydro from employing non-union construction and trade workers for projects on the Burntwood or Nelson Rivers, and *The Manitoba Hydro Act* reserves the exclusive right to "engage in the retail supply of power in Manitoba" to Manitoba Hydro, effectively eliminating any opportunity for potential competitive pricing and service options for the citizens of the Province.

Project structure was constrained by the previous Government's position on public-private partnerships ("**P3**") that may have been useful for sharing the risk of the Keeyask project, thus creating an accountability framework for the project's delivery. This structure has been used by governments across Canada and, when skillfully designed, can protect the public purse from costs and risks that often arise during construction of large-scale infrastructure. *The introduction of The Public Private Partnerships Transparency and Accountability Act* in 2012 described an onerous process to be followed to pursue P3 projects in Manitoba. Premier Selinger, when he was the Minister Responsible for Manitoba Hydro, publicly stated that P3 arrangements were "a back-door route to privatization."[31] The legislation and the public position of the Government constrained the decision space for Manitoba Hydro such that is likely that a P3 arrangement was never seriously considered as the Bipole III and Keeyask projects were advanced.

Public testimony in the Legislative Committee indicated that Government direction with respect to the routing of Bipole III was given in part because of the opposition of Indigenous groups on the east side of Lake Winnipeg. During the review, the Commission heard from Indigenous group leadership that a structure that allowed for equity ownership in Bipole III by Indigenous partners would have helped reduce or even eliminate their opposition. Government documents from that time indicate that the

31 Winnipeg Sun, "Tories open to private-sector Hydro deals," November 13, 2006 [Appendix A, Tab 25].

Government of the day was opposed to equity partnerships on the basis that they could be confused with privatization, which was contrary to government policy.[32]

Excluding Bipole III from NFAT consideration was also a direction of the Government that skewed the analysis of the PDP by treating Bipole III as a sunk cost for all scenarios – even those scenarios where Bipole III was not required to transmit new northern generation. A curious move, specifically excluding consideration of Bipole III influenced the decision of the NFAT Panel to recommend Keeyask for approval and the Commission was told that inclusion of Bipole III would have changed the economic analysis of the various development plans under consideration and very likely would have affected some experts' recommendations to the NFAT Panel.

As noted previously, pre-approval of the KIP also constrained decision making for Keeyask. Experience in the Wuskwatim project, where the project delivery date slipped and costs rose as a consequence, led Manitoba Hydro to propose the KIP to ensure that once approval was received for the generating station, work could proceed immediately. MHEB minutes from 2010 indicate that the MHEB was uncomfortable with proceeding with the KIP prior to negotiation of final export contracts. A briefing note indicates that this reluctance became known to the Government and the briefing note outlined several negative consequences of delaying Keeyask, recommending that the issue be discussed with Manitoba Hydro at the earliest opportunity.[33] Based on this briefing note and the fact that KIP was not cancelled, it is appears that the former Government did not want the project delayed and influenced Manitoba Hydro's decision to proceed with the KIP. It appears that MHEB was doing its job to ensure the export market for Keeyask existed prior to committing significant capital. It is also clear that the Government rejected this advice and pushed the project forward.

The KIP expenditures were a key influence on the NFAT Panel's decision to recommend the project both from a sunk cost perspective and a clear message from the Government that this project had their complete support. This is yet another example of Keeyask being "locked in" prior to formal review of the independent panel.

The Commission notes that while the Government had an active role in moving the Bipole III and Keeyask projects through the approval stages, it took no role in considering the projects prior to submitting them to the regulatory process. The Commission could find no indication that Manitoba Hydro's plans were presented to Treasury Board or any other government body other than the PUB. Matters such as public debt levels and the Province's credit rating were not examined by government notwithstanding the implications of the huge investment proposed by Manitoba Hydro to be guaranteed by the Government. This lack of oversight moved the Government from the role of shareholder to one of cheerleader, with responsibility for analysis and information left in the hands of Manitoba Hydro to be defended in front of the PUB.

This has not always been the case. The Government in the late 1990s and early 2000s was actively pursuing a long-term energy deal with the Province of Ontario based upon the building of the Conawapa Generating Station and a transmission line to facilitate delivery of the power. In anticipation of this, the Government of the day developed a multi-department steering committee with a clear mandate and reporting structure to Cabinet. The plan established working groups in the areas of Training and Employment, Industrial Benefits, Purchasing, Environment Reporting, and Communication. While the sale to Ontario did not materialize, the Government was prepared to actively manage this project and provide oversight and direction to help ensure the success of the project.

32 Manitoba Hydro Submission to Cabinet, "Cree Nation Partnerships in Future Hydroelectric Projects," May 9, 2001.
33 Briefing Note, Department of Finance, "Potential for Keeyask Delays and Negative Consequences," April 16, 2010.

For the Keeyask project it appears that the Government left substantive oversight to the Priorities and Planning Committee of Cabinet and did not avail itself of the expertise in the public service to enhance the analysis and review of the projects.

SECTION 3: THE FUTURE

This section of the review is informed by the record of how the Bipole III and Keeyask projects were developed and brings forward recommendations on how the Government might strengthen processes and procedures going forward.

What Went Wrong?

The lack of clear policy with respect to the project approval process allowed Bipole III to be constructed without proper review. The Commission notes that the Wuskwatim approval combined an NFAT process with the environmental review and included both generation and transmission in the application. Without clear direction with respect to project review requirements, there was a completely different process followed for Keeyask and Bipole III.

The division of the two projects and the designation of Bipole III as a reliability project masked the co-dependent nature of the two projects and allowed a $4.7 billion project to proceed with just environmental review. BCG noted that while the Bipole III and Keeyask projects were disaggregated for public and regulatory consumption, they were inextricably linked and could not exist without each other. This precluded a review of the projects as a whole with the entire proposed investment on the table.

This policy gap will be addressed by the threshold of investment defined in Bill 35 so that projects cannot be approved by the side door without considering their larger impact, cost, and risk.

Integrated Resource Planning (IRP)

Manitoba Hydro made its decisions for new generation on the basis of a load forecast, and in this case, the temporal nature of a prospective Large Industrial Load project that did not ultimately occur. The systemic implementation by Manitoba Hydro of a robust IRP will provide the broad based and integrated plan against which prospective projects can be measured. If this is done objectively and transparently it can negate the potential for pre-determined outcomes and reduce the duration of regulatory hearings by encouraging up-front debate and acceptance of Manitoba Hydro's key planning assumptions. Enshrining the IRP requirement in legislation as proposed in Bill 35 is an important action by the Government to bring Manitoba Hydro into alignment with modern utility management practice. The Commission notes that IRP was the subject of a study prepared for the Government in 2016.[34] The Commission also notes that Manitoba Hydro has been making great strides to bring this modern planning tool into its internal processes, spurred by the new leadership of the company.

Internal Processes with Respect to Planning, Approval, Procurement, and Construction

Manitoba Hydro has a long history of construction of both generation and transmission projects and by all measures the projects that it delivers have been engineered with skill and ultimately constructed in a professional manner as would befit the long-term nature of everything for which Manitoba Hydro

34 Blaine Poff Power Consulting Inc., "Recommendations to Government's Questions for the Adoption of Integrated Resource Planning by Manitoba Hydro," September 30, 2016.

is responsible. Weakness was seen in the Bipole III and Keeyask projects in the planning stage where in the case of Bipole III, new technology was specified and included in cost estimates and it was assumed that the technology would be implementable as the project progressed. The implementability of this technology choice was not reviewed for over three years. This allowed the project to proceed through environmental approval with a price tag that materially understated its actual cost and contributed to a lack of oversight by Government. While a large project, the cost of Bipole III was not of particular note for the former Government other than debate over the perceived $400 million incremental cost associated with the route change.

A much deeper understanding needs to be reached by decision makers (particularly in government) of the vagaries and uncertainty of project estimating as a project goes through the various stages of approval. Internal Manitoba Hydro staff were estimating project costs of $4.1 billion as early as 2011 but this was adjusted to get MHEB approval at $3.28 billion. Government had already seized the earlier estimate of $2.2 billion and enjoyed many hours of debate with the opposition as to whether the $400 million increment for the west side route was worthy. Little did they know that the control budget in 2014 would be $4.6 billion.

Two issues come from this saga – first, the risk of being "locked in" early to a project where the decision maker becomes emotionally and reputationally bound to a project when it is in its very early stages. This can lead to a change in role for the Government from that of decision maker to one of cheerleader for the project. And second, the matter of accountability for estimates and the industry standard practice of establishing appropriate reserve amounts to account for scope change and the inevitable black swans of mega-project development.

Accountability

Throughout the history both the Bipole III and Keeyask projects, the MHEB was presented with ever increasing budgets until eventually the projects were built and could not cost any more. The MHEB certainly raised these issues with management and asked for updated estimates but in each case, they ultimately went along with all of the budget increases sought. This is not an example of an appropriate accountability framework and did not lead to better performance by management in terms of better accuracy or cost containment until the recovery plan for Keeyask was instituted in 2016/17. While Manitoba Hydro management is accountable for its failures through these projects, the MHEB is the organization that is tasked with holding them to account, and until the change in 2016, at no time did the MHEB require better performance from the senior management. The MHEB should be more responsible for holding Manitoba Hydro's management accountable for the accuracy of information they provide to justify major capital projects.

Project Review

The Commissioner believes that the structures exist for robust and complete review of projects in the future. The MHEB, the PUB, and the Government have all of the tools needed to ensure complete analysis of prospective projects and Bill 35 provides legislated authority to do so. What could be added to the already properly prescriptive actions noted in Bill 35 is the ability for the decision-making entities to vary their processes to provide complete analysis. As noted in Section 1, during the NFAT, the NFAT Panel was under a hard deadline and had to accept incomplete analysis and information prior to making its recommendation. The PUB did not have the ability to extend the hearings and with Manitoba Hydro already mobilizing for a start to the project just two months away, there was enormous pressure on the NFAT Panel to just make the recommendation. For a properly functioning review of that magnitude there must be the ability for the regulator to ensure that its work is complete. Schedules are important, but in the case of a multibillion-dollar project, it seems wrong that a full review would lack for just a few weeks. Some method of giving this authority to the regulator should be considered.

The Relationship Between Commercial and Utility-Based Decision Making

Manitoba Hydro has always been a seller of surplus power to export markets both in Canada and the United States. The nature of hydroelectric generation creates this opportunity and in high water years the company has enjoyed an abundance of surplus power that can be sold for profit to others. There is no doubt that this opportunity has had positive effects on the profitability of the company with the attendant virtuous effect of reducing electricity rates for Manitobans and supporting a low cost energy infrastructure with which to attract industrial development in the Province.

Initially conceived as a profitable use of inevitable surplus, the attractiveness of export markets and export pricing saw Manitoba Hydro propose and build the Wuskwatim dam in advance of domestic need to supply an attractive export market at the time. The project went through a modified NFAT/CEC process and was approved. A relatively small development, Wuskwatim was an "assay in the art" of merchant dams that was replayed in the Keeyask planning and approval process.

The logic for an early build of generation supported by firm export contracts until needed by domestic load is a well-known argument made often by politicians and Manitoba Hydro leadership alike. It stands on the success of historical earnings and their positive impact on rates and assumes that this formula is fool proof. As long as the firm contracts can support the operating and capital costs of the project, it appears to be a reasonable approach. The ultimate safety net in these ventures is the evolution of the "merchant" aspects of the dam to a more "utility" based identity as the generation is required for domestic use. The question is one of risk. As long as the firm energy contracts can stay in place and remain profitable, the dam will be parked awaiting emergent domestic need and the plan holds together. But what happens if domestic demand is delayed beyond the firm contract expiry? What happens if the firm export contracts have to be re-signed but at lower prices? Who makes up the difference in revenue from a project that is subject to all the risks inherent in normal commercial ventures? Under the current framework, this risk is borne by the ratepayer.

Precisely this happened with the request from Manitoba Hydro for significant rate increases during the 2017/18 GRA to deal with a poor outlook and a "failed" financial plan. The Commissioner finds this risk to be misaligned, with decision makers that decide to take the risk and passing on the cost to the ratepayer if they are wrong.

Decisions to invest in commercial operations for export can only be made with the approval of Government, as was the case with Keeyask. In the future, the Commissioner proposes that the risk associated with new generation that will, for a period of time, be commercial in nature be aligned with those that benefit. For hydroelectric generation, the Government receives incremental income from the development in the form of water fees, capital taxes, and loan guarantee fees. <u>If a government in the future determines to approve a project that is primarily for export, then for the time frame where the plant is used for export the Government should backstop the economics of the plant by putting its incremental income from that plant at stake</u>. If the market plan fails and export revenues do not cover the cost of operation or the capital charges associated with the project, then the Government should reduce or discontinue the collection of its fees to support the economic needs of the project.

The Commissioner believes that this will assist the Government in properly assessing the efficacy of investing in the commercial ventures in a future and will put its budget at risk for decisions that are made, rather than the ratepayer. The Commissioner believes that adding this accountability would greatly improve decision making at the government level.

Government may wish to add this to their new legislation for future hydroelectric development.

The Manitoba Hydro Act

The Commissioner recommends that the Government consider clarifying *The Manitoba Hydro Act* to better define the duties of Manitoba Hydro as they relate to the provision of domestic power and the pursuit of commercial export opportunities. This issue is just one key element of an energy policy for the Province of Manitoba.

Energy Policy

The changing environment of power generation will place pressure on all power utilities, including Manitoba Hydro. Grid parity has been achieved in parts of Europe and the United States and this will only accelerate in the years to come. Manitoba Hydro has a $32 billion investment in grid power and sells a significant portion into a commercial market. It is reasonable to expect the market to change in the coming years. From a domestic perspective, the Government will need to grapple with the desires of its citizens to produce their own renewable power while still having the provincial grid as a backup. The issue of grid abandonment is topical everywhere in Canada and takes on even more importance when one considers the large industrial sector that may well consider its own generation if rates rise above their own-generation cost of production.

The challenges facing Manitoba Hydro in the future will need the guidance of an energy policy that provides policy space for the future. The policy will inform the integrated resource plan of Manitoba Hydro and allow for a public and transparent position to be proclaimed. Public involvement in the development of this policy is critical and the Commissioner recommends that the process begin as soon as practicable.

Prudent Steps

The financial health of Manitoba Hydro became centre stage with the 2017/18 GRA. Pursuant to the identification of significantly increased construction costs of Keeyask and a softening export market, Manitoba Hydro proposed a dramatic series of rate increases to return the company's financial ratios to pre-development levels.

While this application for five years of 7.9% rate increases was denied, it highlighted the additional risks Manitoba Hydro faces in a time of significant capital investment. Important measures of financial health for Manitoba Hydro are debt-to-capitalization ratio, interest coverage ratio, and capital coverage ratio. It is expected, and was presented during NFAT, that many of these financial ratios would deteriorate upon the completion of the projects due to the significant increase in debt and the debt servicing costs therein.

The impact of the weakening of these ratios is a reduced ability for Manitoba Hydro to address the systemic risks it faces associated with water levels, weather impact on demand, and revenue risk in the commercial export markets. There is also the concern that Manitoba Hydro's financial structure could affect the debt markets for the Government of Manitoba should the company's debt be deemed not supported by their business activities.

We note that the Government has taken steps to provide guidance to Manitoba Hydro with respect to improving its financial metrics. Bill 35 legislates a series of debt-to-capitalization levels that over a 20-year horizon will return Manitoba Hydro to a 70/30 capitalization ratio.[35] The Bill allows rate increases to provide sufficient revenue to achieve these targets.

The Commissioner believes that this element of the Bill recognizes that the major risks associated with Manitoba Hydro's income statement are by and large outside of its control. While the magnitude of the risks has increased, the tools to address them have not. As noted earlier, Keeyask is going to be supported by export revenue for many years, a revenue source that is subject to water levels providing supply for opportunity sales, the vagaries of a competitive export market changing rapidly as new technology is deployed, and an unpredictable regulatory environment subject to political winds of change. The time frame proposed and the full expectation that rate increases can be used to meet these targets gives a clear message to the markets that Manitoba Hydro will be self-sustaining and will improve its financial ratios in the future. Thus, the question of the sustainability risk of unsupported debt is mitigated for the capital markets.

By relaxing the debt-to-capitalization ratio for a period of time, the Government has recognized the reality of large capital expansion and provided the company with the flexibility to meet the targets over a long planning horizon. However, with this breathing space comes responsibility.

To minimize rate increases, Manitoba Hydro must execute its management and export marketing plans with great skill and Manitoba Hydro must be accountable for its performance within the elements it controls. Increasing revenue, vigorous cost containment, and reducing debt should be a focus of Manitoba Hydro in the coming years.

To increase revenue, Manitoba Hydro should consider exploring partnerships in transmission – particularly in the international export market which could provide incremental capital to the corporation and reduce the risk that exists in the debt refinancing planned for the next five years.

The Commissioner believes that Manitoba Hydro should also look at its various subsidiary elements and determine if those operations are core to its mandate and duty. If elements are not core to its mission, then they should be considered for sale or shutdown. Monetization of assets could help relieve the debt burden sooner and reduce rate increases in the future. This will also allow management to focus on its core responsibilities with a particular emphasis on execution of its business plan without the distraction of managing operations in other sectors.

The Commissioner understands that the consideration of the future of non-core subsidiaries requires a more flexible policy framework than was available in the past, but believes that the ratepayers of Manitoba deserve every opportunity to maintain their low electricity rates and Manitoba Hydro needs to focus on this without distraction. The major generation and transmission capital plan nearing its completion brings new and magnified risk to the company and there is little room for error in the changing world.

The Commissioner would like to acknowledge and encourage the work of Manitoba Hydro, previous and current Manitoba Governments, and the federal government for pressing the opportunity for export sales to other Canadian provinces.

In October 2018, Manitoba Hydro announced the sale of 215 MW to the Saskatchewan power utility, SaskPower, beginning in 2022. In March 2020, the federal government announced $18.7 million in funding to support the construction of the new transmission line required to carry the electricity

35 Bill 35, *The Public Utilities Ratepayer Protection and Regulatory Reform Act (Various Acts Amended)*, 3rd Sess., 42nd Leg., 2020, s. 39.1(1)(c)(i).

sold in this agreement, thereby increasing the use of emissions-free Manitoba Hydro power by Saskatchewan residents and businesses. In this report, the Commissioner recommends that Manitoba Hydro focus on its core functions as it rebuilds its balance sheet and assures the Manitoba low electricity rate advantage for the long term. The Commissioner believes that export sales to other provinces, including federal government support and a Canadian vision for a western Canadian and national grid, is worthy of inclusion in any list of core activities.

Credit is due to previous premiers and Manitoba's current premier for making the strong case for a national (and at very least a western Canadian) grid a priority for national discussion and consideration.

Summary

Manitoba Hydro is a key asset for Manitoba. It has provided reliable service at low rates for decades. However, through over optimism with respect to the opportunities in the export market and a pre-determined development path with no available off-ramps, the company has overbuilt the generation assets needed for domestic use for many years. The company is now more exposed to risk and, as always, the ratepayer stands as the guarantor.

Historically, one could take the position that the domestic need will appear at some time in the future and the investment will be proven acceptable, just maybe a little early. The modern electrical generation landscape makes that claim less certain. Grid parity, grid abandonment, changing economics, and the impact of climate change on water levels for hydroelectric power generation make the future position of large-scale grid power uncertain. There is no question that Keeyask will generate electricity for many decades and Bipole III will provide reliability and, with the intertie, will dutifully transmit the power to a large U.S. market. The future economics have proven difficult to predict through all the reviews. The Commissioner will not opine on what may happen in the coming years, but does offer the encouragement to Manitoba Hydro and the Government to control what they can and make decisions based upon a somewhat less optimistic forecast – but one that always has hope.

The Government and Manitoba Hydro will be tasked with finding their path in this new environment and the Commissioner believes that the formation of reasonable policies and the commitment to best practices will prevail in the uncertain future of electrical supply and markets.

CHAPTER 1

Domestic Need for the Projects

> *"While the need for reliability was identified by 1975, Bipole III was not formally advanced until new northern generation that required it for transmission was also being advanced … It was only in December 2011 – four months after the export contracts requiring construction of Keeyask had received Cabinet approval – that Manitoba Hydro applied for the necessary Environment Act licence to build Bipole III."*

INTRODUCTION

In accordance with section 1 of the Terms of Reference, the Commission inquired into the extent to which Manitoba Hydro pursued the Keeyask and Bipole III projects when they were not necessary, or not necessary at the time, to meet the Province's then-anticipated electrical needs in a timely and cost-effective manner.

This chapter presents the Commissioner's findings and recommendations from this inquiry.

BIPOLE III

Need for Enhanced System Reliability

The need to minimize the risk of simultaneous failure of Bipoles I and II (including during major disasters) was identified by Manitoba Hydro at least as early as 1975, when it was recommended that Bipole III be sufficiently separated from them to minimize the risk of simultaneous failure of all three lines.[36]

Manitoba Hydro provided an overview of its system reliability issues in chapter 2 of the environmental impact statement that was submitted to the CEC in 2011 as part of its review of Bipole III. In that chapter, Manitoba Hydro described how about 70% of Manitoba's entire generation supply was carried by Bipoles I and II through the same interlake corridor, and how Manitoba had the highest concentration of supply along one corridor and one converter station (Dorsey) of any corridor in the world. It further described how Manitoba's HVDC transmission system was extremely vulnerable to weather or other events that could damage Bipoles I and II or the Dorsey Converter Station, and how:

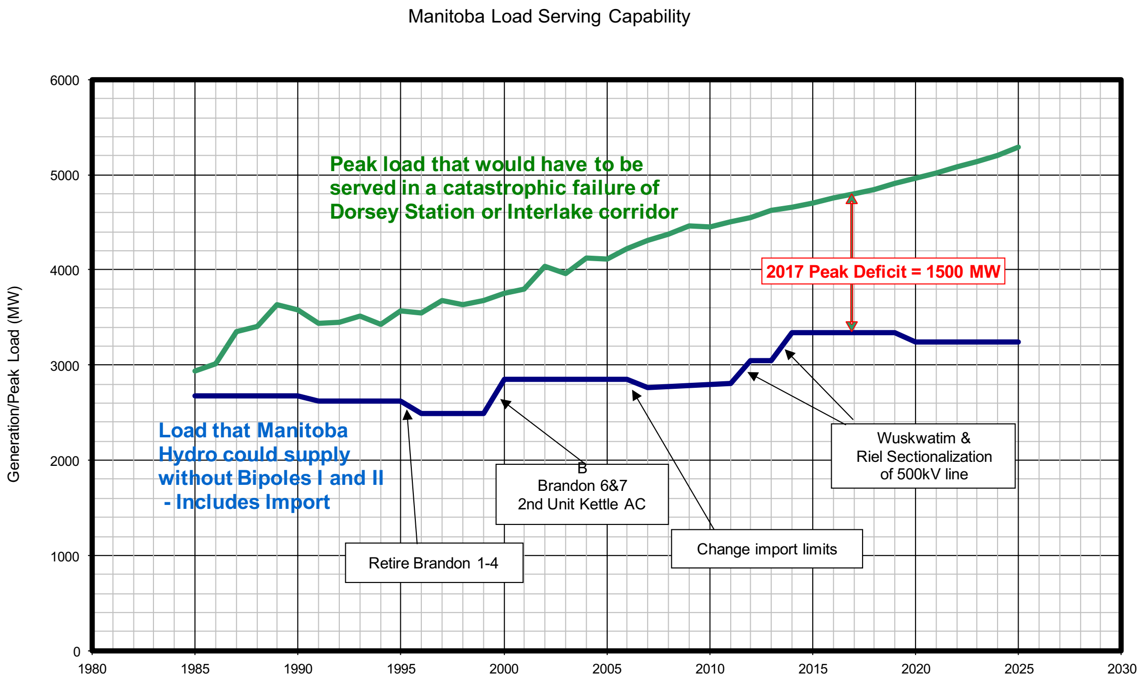
- such damage at Dorsey could result in a loss of about 70% of Manitoba's generation supply for up to three years "because of the time required to repair or replace equipment of such complexity"; and
- such damage to Bipoles I and II could cause a loss of about 70% of Manitoba's generation supply for six to eight weeks.[37]

In the event of an extended HVDC outage and the loss of about 70% of Manitoba's generation supply, there would be a supply deficit and Manitoba Hydro would not be able to serve the peak load, which could necessitate rotating blackouts. This potential supply deficit would grow over time because of

36 Manitoba Hydro, System Planning Division, Transmission Planning Department, "Report on Location of the Third Bipole Receiving End Station," SPD 75-25, June 6, 1975, p. 2.

37 Manitoba Hydro, Environmental Impact Statement (Bipole III), December 2011 ("**EIS**"), Chapter 2: Need and Alternatives, p. 2-2 [Appendix A, Tab 26].

load growth (i.e., the higher the load, the higher the deficit).[38] This growing peak deficit is shown in the figure below:[39]



To put the estimated winter peak deficit for 2017 into perspective, the 1500 MW shortfall would be equivalent to the power demand of approximately 300,000 average residences, based on an average peak demand of 5 kVA per household.[40]

The potential effects of an HVDC outage were considered unacceptable, particularly given the economic impact and the serious effects on health, safety, and security from having no power for extended periods during very cold winter months.[41]

In 2001, studies for Manitoba Hydro evaluated the potential of catastrophic failure of either Bipole I and II or Dorsey due to fire and extreme weather events. The probabilities determined for such losses are set out in the table below.[42]

Catastrophic Failure of Dorsey	
Cause of Outage	Probability
Fire	1 in 29 years (partially addressed by mitigation measures put in place)
Wide front winds	1 in 200 years
Catastrophic Failure of Bipoles I and II	
Cause of Outage	Probability
Tornado	1 in 17 years
Icing	1 in 50 years
Wide front winds	1 in 250 years

38 EIS, Chapter 2, p. 2-2 [Appendix A, Tab 26].
39 EIS, Chapter 2, p. 2-6 [Appendix A, Tab 26].
40 EIS, Chapter 2, p. 2-5 [Appendix A, Tab 26].
41 EIS, Chapter 2, p. 2-3 [Appendix A, Tab 26].
42 EIS, Chapter 2, p. 2-5 [Appendix A, Tab 26].

A 1996 wind event has repeatedly been cited by Manitoba Hydro as a "near-miss" experience that highlighted the need for a major reliability enhancement. It described this event as follows:

> On September 5, 1996 a downburst wind event caused the failure of 19 Bipole I and II transmission towers just two km north of Dorsey Station. Had this event occurred closer to Dorsey Station, it could have also taken down the Dorsey-Forbes 500 kV **interconnection** which would have in turn reduced the amount of power that could be imported from the United States. It took over four days to restore one HVdc line. Bipole I and II converters were then operated on this one line until the second dc line was repaired.
>
> Due to the time of year (September), the load was relatively low. Manitoba Hydro managed to serve the entire load during this event by relying heavily on arranged imports of up to 985 MW of power from the USA and neighbouring provinces, as well as by appealing to the public to reduce consumption. Had the event occurred just a month or two later in the year when load levels would have been higher, rotating blackouts would have been unavoidable.[43]

A level 5 tornado that set down on June 22, 2007 and caused extensive damage in Elie – which is just west of Winnipeg and only 30 kilometres south of Dorsey – is another event that has been cited by Manitoba Hydro as a "near-miss" that highlighted the need for a major reliability enhancement.[44]

While the need for reliability was identified by 1975, Bipole III was not formally advanced until new northern generation that required it for transmission was also being advanced. As discussed in further detail later in this chapter, the justification for Bipole III was consistently tied to new northern generation and exports, starting in the early 1990s with Conawapa and a potential sale to Ontario. Throughout the 2000s, the ability of Bipole III to deliver power from new northern generation for export purposes was touted in documents from Manitoba Hydro, in addition to its reliability benefits. It was only in December 2011 – four months after the export contracts requiring construction of Keeyask had received Cabinet approval – that Manitoba Hydro applied for the necessary *Environment Act* licence to build Bipole III.[45]

Finding #1.1: To meet the Province's electrical needs, Manitoba's electric system needed to be upgraded and diversified to ensure the availability of supply following a potential extreme weather event and catastrophic damage to Bipoles I and II or the Dorsey Converter Station. This was evidenced based on the growing peak deficit in the event of an HVDC outage.

Finding #1.2: Bipole III was not pursued in a timely manner. The need for a reliability solution was identified in 1975. The wind event that was repeatedly cited by Manitoba Hydro as a "near-miss" experience that highlighted the need for a major reliability enhancement occurred in 1996. Bipole III first appeared in Manitoba Hydro's capital expenditure forecast in 1999. The in-service date for Bipole III was then pushed back in order to pursue the western routing, and it only entered into service in July 2018.

43 EIS, Chapter 2, pp. 2.3-2.4 [Appendix A, Tab 26].
44 EIS, Chapter 2, pp. 2.4-2.5 [Appendix A, Tab 26].
45 See, for example, Letter from Dave Chomiak, then Minister of Conservation, to Terry Sargeant, then Chair of the CEC, December 5, 2011 [Appendix A, Tab 27].

Finding #1.3: While Bipole III now provides reliability benefits, the impetus for building it was not for reliability purposes. It may have originally been contemplated for that purpose; however the history of the project outlined in this chapter and the timing of its construction makes clear that it was built to accommodate new northern generation (including Keeyask) and export sales, despite representations to the contrary. As discussed later in this report, even though Bipole III was critical to enable the building of Keeyask, the former Government opposed a review of them together.

Options to Meet Reliability Need

Four Options Identified

Bipole III on the west side of the Province – the project that entered service on July 4, 2018 – was not the only possible option identified by Manitoba Hydro to enhance the reliability of its electric system. The options that were identified in documents from Manitoba Hydro were:

- Bipole III on the east side of the Province ("**Bipole III East**");
- Bipole III on the west side of the Province ("**Bipole III West**");
- Bipole III through an interlake route;
- 2000 MW of natural gas generation in southern Manitoba ("**All Gas**"); and
- 1500 MW of new imports from the U.S., plus 500 MW of natural gas generation in southern Manitoba ("**Import + gas**").

No independent review was carried out to determine which of these options was the best solution to address the reliability issue at the lowest cost.

In the EIS submitted to the CEC as part of its review of Bipole III West, Manitoba Hydro provided a very high-level comparison of the Bipole III West, All Gas, and Import + gas options and concluded that Bipole III West was "the superior reliability solution at the least capital cost."[46] However, no detailed comparison or review of alternatives was performed as part of the review[47] and Bipole III East was scoped out of the review. Flaws in Manitoba Hydro's high-level comparison of the other three options in the EIS are discussed in Chapter 3 of this report.

Bipole III was also excluded from the NFAT[48] process and therefore no detailed comparison or review of it or its alternatives was performed as part of that process, either.

In 2016, after construction on Bipole III West was already underway, BCG performed a review of Bipole III alternatives for the MHEB, which considered each option listed above with the exception of the Bipole III interlake route. BCG concluded that Bipole III East was likely the lowest-cost option, and that Bipole III West was the next lowest cost option.[49] The BCG review included very similar limited information as the EIS and, therefore, the flaws in Manitoba Hydro's high-level comparison of three options other than Bipole III East that are discussed in Chapter 3 also apply to BCG's comparison.

46 EIS, Chapter 2, p. 2-13 [Appendix A, Tab 26].
47 A motion to compel Manitoba Hydro to provide more information on Bipole III needs and alternatives was dismissed on the basis that the terms of reference did not include a review of the needs for and alternatives to Bipole III: Decision of the CEC on the Motion of the Bipole III Coalition, August 29, 2012 [Appendix A, Tab 27].
48 NFAT Report, pp. 39, 261 [Appendix A, Tab 15].
49 BCG, "Bipole III, Keeyask and Tie-Line Review," September 19, 2016, pp. 4-5 [Appendix A, Tab 28].

Finding #1.4: Bipole III was one of several possible solutions to address the reliability issue facing Manitoba's electric system. No independent review was carried out to determine which of these options was the best solution to address the reliability need at the lowest cost. Given the scale and cost of Bipole III, an independent regulatory review should have been performed to show that it was the best option to meet the Province's anticipated electrical needs.

Recommendation #1.1: Transmission and generation should both be considered in an ongoing IRP process. If there is a need (e.g., for reliability), it should be discussed in such a process along with potential solutions. A need should not be allowed to go unaddressed for decades until a solution for that need can be justified by a profit motive, as was the case for Bipole III. An IRP process involves the consideration of alternatives well in advance of when a business case for an option is finalized and ready for regulatory review. The Commissioner supports changes proposed in Bill 35, whereby Manitoba Hydro will have to regularly prepare and submit to the Minister an IRP, taking into account government policies, risk, and financial targets, among other things. However, the Commissioner is of the view that this IRP, while led by Manitoba Hydro based on criteria set by Government, should be developed through a public process involving independent experts and overseen by an independent regulator such as the PUB, rather than by Manitoba Hydro alone.

Recommendation #1.2: The Commissioner is supportive of the changes in Bill 35 that would require Treasury Board approval for Manitoba Hydro's capital expenditure programs. This provides a process by which government (a party other than Manitoba Hydro) can assess the financial implications of a proposed capital expenditure program or project like Bipole III on the Province and taxpayers. Bill 35 would also require a review by the PUB for any new transmission line with a voltage higher than 230 kV, if $200 million or more of investment is required by Manitoba Hydro. Such reviews would consider impacts on rates and Manitoba Hydro's financial health. In the Commissioner's view, an independent technical assessment of whether a proposed project is necessary and should be pursued over other possible alternatives, as well as the reasonableness of Manitoba Hydro's underlying forecasts, should also be required, along with an assessment of whether a proposed project is consistent with provincial energy policy.

Comparison of Bipole III East and Bipole III West

In the original CPJ[50] for Bipole III in 2001, an 800-kilometre line was proposed on the east side of the Province (i.e., Bipole III East) at a cost of $360 million. Bipole III East was recommended as a "transmission only alternative" to provide increased reliability in the Manitoba Hydro System that would also provide an increase in power to the south of about 78 megawatts due to decreased line losses.[51] No converter stations were included at the time since they were not expected to be required until the completion of new northern generation projects. However, it was estimated that the two converters that would ultimately be added would cost a total of approximately $1 billion.[52]

In 2005, Manitoba Hydro prepared a CPJ addendum that reflected a west-side routing (i.e., Bipole III West), comprising a transmission line of at least 1,265 kilometres at a "placeholder" cost of $1.88 billion. This estimate reflected the longer line (approximately 60% longer) and two converters, which would be required in advance of new generation due to the inability for the longer line to work with existing

50 A CPJ framework is used by Manitoba Hydro to summarize technical, economic, and financial information for a project that is being proposed or revised for inclusion in its capital program. Once the need for a capital project is identified, a CPJ is prepared by Manitoba Hydro. Information relative to each project such as a business case, risk assessment, resourcing requirements, and other pertinent details are presented in the CPJ. Proposed capital expenditure projects are reviewed and approved by both Manitoba Hydro's management and executive prior to their inclusion in Manitoba Hydro's CEF (which is described below). See, for example, 2012/13 GRA, Information Request (IR) CAC/MH II-47 [Appendix A, Tab 29].

51 2017/18 GRA, PUB Minimum Filing Requirement (MFR) 155, Original CPJ [Appendix A, Tab 30].

52 PUB Order No. 7/03, p. 18 [Appendix A, Tab 31].

converters on Bipoles I and II (unlike Bipole III East). In that addendum, Manitoba Hydro identified several reasons why Bipole III West was inferior compared to Bipole III East, including:

- it was a less reliable solution since it would only accommodate 2000 MW of supply from northern generation in the event of a Bipole I and II corridor outage, whereas Bipole III East would allow the paralleling of Bipole I and II converters on the Bipole III line and thus accommodate 3300 MW of northern generation;
- the longer line length of Bipole III West would increase exposure to outages on Bipole III;
- a delayed in-service date compared to Bipole III East, placing Manitoba Hydro customers at a greater risk for a longer period of time; and
- Bipole III West would likely be considerably longer than the 1,265 kilometres included in the estimate and thus cost more and result in more line losses.[53]

A government document from 2005 included information about the then-estimated costs of Bipole III East and a comparison to the then-estimated costs of Bipole III West. The document stated that an 820-kilometre Bipole III East would have a capital cost of $398 million, whereas the 1,265- to 1,456-kilometre Bipole III West would cost $500 million more ($200 million for extra line length and $300 million in line losses). It further noted that Bipole III West would require the advancement of the converters that Bipole III East would only later require to transmit new northern generation, and that those converters would cost $1.2 billion.[54] This same cost of the converters – $1.2 billion – was reflected in Manitoba Hydro's CEFs from 2006 to 2010.[55]

In submissions to the PUB after 2005, Manitoba Hydro identified that the capital cost of Bipole III West was $400 million higher than that of Bipole III East (not including the advanced converters) and that it would cause an additional line loss of up to $181 million. Manitoba Hydro also advised that an outage of Bipoles I and II during the summer season could cost $160 million more in imports if Bipole III West were built as opposed to Bipole III East, in order to make up for the lower amount of northern generation that Bipole III West could provide in the event of such an outage (as noted above).[56]

In 2016, BCG identified the increased costs of Bipole III West compared to Bipole III East as $900 million.[57] The PUB accepted that differential in its finding during the 2017/18 GRA that the final cost of Bipole III was $900 million higher due to the choice of Bipole III West over Bipole III East.[58]

Finding #1.5: Bipole III was not pursued in a cost-effective manner to resolve the reliability issue facing Manitoba's electric system, particularly given its final cost of $4.77 billion. Bipole III East would have been considerably less expensive due to the shorter line length and lower line losses. Unlike Bipole III West, Bipole III East could also have been built without requiring expensive converters (costing $1.2 billion or more), at least until the completion of new northern generation projects in the future.

53 2017/18 GRA, PUB Minimum Filing Requirement (MFR) 155, Addendum #04 [Appendix A, Tab 30].
54 Briefing Note, Department of Finance, "Bipole III - Routing Options," November 23, 2005, p. 2.
55 2017/18 GRA, PUB Minimum Filing Requirement (MFR) 154 [Appendix A, Tab 32].
56 PUB Order No. 116/08, pp. 141-142 [Appendix A, Tab 33].
57 BCG, "Review of Bipole III, Keeyask and Tie-Line Project," September 19, 2016, p. 2 [Appendix A, Tab 22].
58 PUB Order No. 59/18, pp. 95, 98, 181 [Appendix A, Tab 34].

Finding #1.6: Bipole III West was inferior to Bipole III East from a technical perspective. In the event of an outage of Bipoles I and II, Bipole III East would have been able to provide at least 50% more electricity from northern generation than Bipole III West. This ability to provide more electricity would have required less of the shortfall to be made up by importing electricity and would have thus saved further costs. The shorter line length would have also reduced the exposure to outages as compared to Bipole III West. Following the addition of converters to Bipole III East to transmit new northern generation, Bipole III East would have provided the same reliability benefit as Bipole III West in the event of an outage of Dorsey.

The Choice to Proceed with Bipole III West

Bipole III East was the first option considered by Manitoba Hydro to enhance the reliability of its electric system.

In the early 1990s, the potential for a 1000 MW sale to Ontario moved up the schedule for Bipole III and Conawapa, as Bipole III would have been needed to transmit Conawapa's power south as part of the sale.[59] At that time, Bipole III was planned for the east side of Lake Winnipeg. The sales agreement with Ontario was cancelled in 1992 and neither Bipole III nor Conawapa was built.[60]

By 1999, Bipole III again appeared in CEF 99-1[61] as "HVDC Conversion Bipole 3/Conawapa Transmission" under the heading "Transmission for Generation." CEF 99-1 explained the justification for Bipole III as one of load linked to Conawapa's new generation:

> Based on the 1999 Load Forecast, generation expansion studies indicate an additional generation source is required in 2018/19. Conawapa is the current economic choice. Bipole 3 facilities are necessary to connect this new power source to the Manitoba network.[62]

In 2001, the original CPJ for Bipole III contemplating an east side route was approved by Manitoba Hydro's executive committee.[63] Minutes of the MHEB from around that time similarly mention the construction of Bipole III on the east side of Lake Winnipeg, with no talk of alternative routes or projects. It was noted that Bipole III would have significant benefits in terms of increasing system reliability for domestic and export revenue purposes.[64]

Manitoba Hydro's CEF from November 2001 also included Bipole III on the east side of Lake Winnipeg. No converter stations were included in this forecast since they were not expected to be required until the completion of new northern generation projects.[65]

In a September 2003 briefing note, Manitoba Hydro stated that Bipole III was required to improve system reliability, and that it could also deliver power from future generation development in northern Manitoba. It identified three conceptual options for new transmission between northern power sources and southern load: (i) Bipole III East; (ii) an interlake Bipole III; and (iii) Bipole III West. Balancing

59 PUB Order No. 5/12, p. 127 [Appendix A, Tab 35].
60 Manitoba Hydro, System Planning Division, "Bipole III: Past, Present and Future," Presentation at the 2019 Minnesota Power Systems Conference, November 13, 2019, p. 13 [Appendix A, Tab 36].
61 The CEF is a projection of Manitoba Hydro's capital expenditures for new and replacement facilities to meet the electricity requirements in the Province of Manitoba as well as expenditures required to meet firm sale commitments outside the Province. Expenditures included in the CEF are supposed to include those necessary to provide a safe and reliable supply of energy in the most efficient and environmentally responsible manner. See, for example, 2015/16 GRA Tab 4, p. 2 [Appendix A, Tab 37].
62 Manitoba Hydro, Capital Forecast (CEF 99-1), October 1999 [Appendix A, Tab 38].
63 The justification for Bipole III cited a July 4, 2001 System Planning report entitled "Minimum Transmission Requirements for HVDC Bulk System Reliability" (SPD 01/7), which recommended a Bipole III transmission line routed east of Lake Winnipeg. The original CPJ for Bipole III was dated less than one month prior to that report (June 13, 2001). 2017/18 GRA, PUB Minimum Filing Requirement (MFR) 155, Addendum #06 [Appendix A, Tab 30].
64 Minutes of MHEB Meeting, September 20, 2011.
65 Board Order No. 7/03, p. 18 [Appendix A, Tab 31].

cost and technical factors against environmental and socio-economic concerns, Manitoba Hydro recommended Bipole III East as the only acceptable option.[66]

In a briefing note to the MHEB in August 2004, Manitoba Hydro stated that it considered a number of alternative corridors when planning Bipole III, but Bipole III East was the preferred option based on technical, cost, reliability, and other considerations. The alternative interlake route was considered unacceptable because of its proximity to Bipoles I and II. However, given the opposition to Bipole III East by international environmental non-governmental organizations ("**ENGOs**"),[67] Manitoba Hydro recommended that a detailed technical study of Bipole III West be conducted and that a strategy be developed with the Province to deal with environmental organizations, both in the context of Bipole III and a potential Ontario sale that depended on Bipole III.[68] During a meeting that month, the MHEB accepted these two recommendations and established a sub-committee to monitor this issue.[69]

In June 2005, Manitoba Hydro prepared a CPJ addendum that reflected Bipole III West and identified several reasons why Bipole III West was inferior compared to Bipole III East. The addendum stated that Manitoba Hydro was advancing Bipole III West as a "placeholder" in response to a request from the MHEB to look at alternative routings to Bipole III East, and that Manitoba Hydro would make a recommendation for Bipole III routing in October 2006.[70]

In a November 2005 briefing note, Manitoba Hydro reiterated its preference for Bipole III East and that an interlake route was not acceptable because of the inability to achieve adequate physical separation from Bipoles I and II. Manitoba Hydro also stated that Bipole III West could be feasible but required further technical studies to confirm its viability and implications, which would delay the in-service date. The briefing note indicated that a preliminary review of a gas option in southern Manitoba indicated that it would be a "very costly" alternative, and that an import option would require extensive negotiations leading to delays. Finally, the note indicated that timing implications for Bipole III led to serious concerns about the viability of future development of Manitoba Hydro's proposed northern hydroelectric projects and its proposed sales with Ontario and in the U.S.[71]

In October 2006, Manitoba Hydro submitted its recommended routing for Bipole III to the MHEB. Manitoba Hydro reiterated that Bipole III East was its preferred option from an economic, technical, and reliability perspective. However, given the premise that Bipole III East was not available, Manitoba Hydro stated that Bipole III West with 2000 MW converters would address reliability on the electric system. It again reiterated the issues with Bipole III West that were raised in the June 2005 CPJ addendum.[72]

On September 20, 2007, then-Minister Greg Selinger sent a letter to the Chair of the MHEB (Vic Schroeder at the time) that eliminated Bipole III East from consideration and mandated that Manitoba Hydro consider alternative routes. In that letter, Mr. Selinger recognized the importance of Bipole III "to improving system reliability and accommodating future northern generation" but stated that the Government of Manitoba "did not regard an east side Bipole III as being consistent" with certain commitments and initiatives listed in that letter (which are discussed below).

66 Briefing Note, Department of Finance, "Bipole III Conceptual Options," September 30, 2003.
67 The briefing note referenced "increasing pressure" from ENGOs to establish formal protection of large portions of the boreal forest area east of Lake Winnipeg, before industrial developments in the area. It specifically noted a recent tour by Robert Kennedy Jr., a representative of the international ENGO called the Natural Resources Defence Council ("**NRDC**"), as well as the NRDC's recently launched campaign to "save" a new Biogem for the boreal forest area east of Lake Winnipeg by promoting its protection from development impacts, including hydroelectric development. Manitoba Hydro, Transmission & Distribution, "Board Discussion Item, Bipole III Corridor," August 12, 2004, p. 1.
68 Manitoba Hydro, Transmission & Distribution, "Board Discussion Item, Bipole III Corridor," August 12, 2004.
69 Minutes of MHEB Meeting, August 18, 2004.
70 2017/18 GRA, PUB Minimum Filing Requirement (MFR) 155, Addendum #04 [Appendix A, Tab 30].
71 Briefing Note, Department of Finance, "Bipole III - Routing Options," November 23, 2005.
72 Manitoba Hydro, System Planning, "Report on Manitoba HVDC Reliability Alternatives Phase II," SPD 2006/11, October 4, 2006, pp. 3-4.

The paragraph in question reads as follows:

> It is the policy of the Manitoba Government to make its government decisions about development on the east side in a manner consistent with the above-noted commitments and initiatives. The Manitoba Government does not regard an east side Bipole III as being consistent with these commitments and initiatives. We recognize the importance of the Bipole III initiative to improving system reliability and accommodating future northern generation. We would encourage the corporation to move ahead with required consultations and planning for an alternative Bipole III route.[73]

The letter cited a then-recent report from CMC Consultants Inc. (Mr. Dave Farlinger), which highlighted that Bipole III East could be problematic in light of (1) efforts to protect the boreal forest on the east side of Lake Winnipeg and achieve a UNESCO World Heritage Site designation, (2) opposition to Bipole III East from Indigenous groups, and (3) threats to Manitoba Hydro's reputation and exports.[74]

By that time, Manitoba Hydro had already eliminated non-Bipole III options,[75] as well as the alternative interlake route (because of its proximity to Bipoles I and II). The Commission heard that, following receipt of the letter from Mr. Selinger, the MHEB did not discuss any alternatives to Bipole III, including natural gas-fired generation.[76] This suggests that Manitoba Hydro did not seriously consider the project alternatives to Bipole III discussed in the EIS (i.e., the All Gas and Import + gas options), at least not as of 2007, and that the alternative western route (Bipole III West) was the only option considered for Bipole III after September 2007.

Mr. Selinger's letter noted that Bipole III East threatened a UNESCO World Heritage designation and Manitoba Hydro's commercial reputation in export markets. This rationale is consistent with what the Commission heard during interviews with a former senior government official and with former members of Cabinet. During interviews, the Commission heard that the former Government was concerned that Manitoba's ability to sell electricity to the U.S. would be negatively affected by any decision to build Bipole III on the east side of the Province, particularly when First Nations and ENGOs in the U.S. were supporting the designation of the area as a UNESCO World Heritage site.[77] The Commission also heard that the former Government believed that such a designation could not have been achieved if Bipole III was built on the east side of the Province.[78]

The Commission heard about a curious belief of the Government of the day that the construction of a road through the proposed UNESCO World Heritage Site on the east side of the Province was more acceptable than the construction of Bipole III through the same area.[79] Senior elected officials from the time indicated that this was their understanding.[80] However, there was no clear evidence that a UNESCO World Heritage Site designation could not have been achieved if Bipole III was constructed on the east side, nor that a road was more compatible with a UNESCO World Heritage Site designation than a transmission line.[81]

73 Letter from Greg Selinger, then Minister Responsible for Manitoba Hydro, to Vic Schroeder, then Chair of the MHEB, September 20, 2007 [Appendix A, Tab 39].

74 Letter from Greg Selinger, then Minister Responsible for Manitoba Hydro, to Vic Schroeder, then Chair of the MHEB, September 20, 2007 [Appendix A, Tab 39].

75 The study by CMC Consultants Inc. only considered different routes for Bipole III and it did not consider any other options for the reliability issue. CMC Consultants Inc., "Bipole III Transmission Routing Study," September 2007 [Appendix A, Tab 40].

76 Information received from participant, March 10, 2020.

77 Information received from participant, April 21, 2020.

78 Information received from participant, July 15, 2020; Information received from participant, October 21, 2020.

79 Information received from participant, April 21, 2020.

80 Information received from participant, July 15, 2020.

81 Information received from participant, April 21, 2020.

Mr. Selinger's letter also noted that there was a lack of First Nations consensus on building Bipole III on the east side that was reflected in the 2004 report entitled *Promises to Keep: Towards a Broad Area Plan for the East Side of Lake Winnipeg*.[82] This report is interesting because it indicates that there was no consensus about building a road on the east side, either,[83] and that support for Bipole III might have been earned through consultation and engagement with First Nations.[84]

There is no evidence that the former Government seriously pursued options with Indigenous groups affected by Bipole III East that could have addressed their concerns. For example, the Commission heard from Indigenous leadership that a structure that allowed for equity ownership in Bipole III by First Nations partners could have made a material difference and helped reduce or eliminate Indigenous opposition to Bipole III East.[85] However, documentation received from the Government indicates that the Government of the day was opposed to equity partnerships on the basis that they could be confused with privatization, which was contrary to government policy.[86]

Further, as also discussed in Chapter 4 of this report, the costs of Bipole III West escalated over time. Even when the estimate increased significantly from $3.28 billion to $4.65 billion (the final pre-construction budget) in August 2014,[87] there is no evidence that Manitoba Hydro reconsidered the decision to proceed with Bipole III West. This may not be surprising, given that Keeyask had been approved at that time with a planned in-service date of 2019, and Keeyask required Bipole III to transmit all of its capacity.

82 Letter from Greg Selinger, then Minister Responsible for Manitoba Hydro, to Vic Schroeder, then Chair of the MHEB, September 20, 2007 [Appendix A, Tab 39].

83 Phil Fontaine & Ed Wood, *Promises to Keep: Towards a Broad Area Plan for the East Side of Lake Winnipeg*, November 2004, Appendix 8.10, pp. 2, 33, Appendix 8.11, pp. 13, 26, 29 [Appendix A, Tab 41].

84 See, for example, Phil Fontaine & Ed Wood, *Promises to Keep: Towards a Broad Area Plan for the East Side of Lake Winnipeg*, November 2004, Executive Summary, p. 50 [Appendix A, Tab 42].

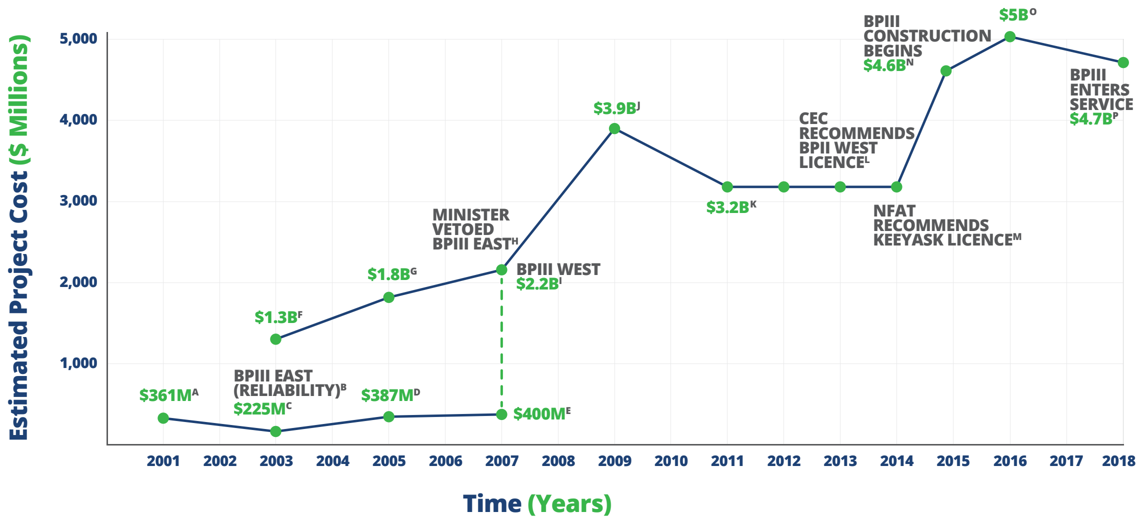
85 Information received from participant, May 1, 2020

86 Manitoba Hydro Submission to Cabinet, "Cree Nation Partnerships in Future Hydroelectric Projects," May 9, 2001.

87 Manitoba Hydro, Capital Expenditure Forecast (CEF14), December 2014, pp. 13-15 [Appendix A, Tab 43].

The timing of key decisions related to Bipole III and escalating costs of the project are shown in the figure below:

Key Decisions and Rising Costs of Bipole III



- A 2017/18 GRA, MFR 155, Original CPJ [Appendix A, Tab 30].
- B Costs for Bipole III East do not include converters since it was proposed as a pure reliability project, for which converters were not required until new northern generation was built. Bipole III West required converters regardless of new northern generation. See, e.g., 2017/18 GRA, PUB Minimum Filing Requirement (MFR) 155, Original CPJ, Addendum #01 and Addendum #04 [Appendix A, Tab 30].
- C Manitoba Hydro, Briefing Note, "Bipole III Conceptual Options," September 30, 2003.
- D 2017/18 GRA, MFR 155, Addendum #04 [Appendix A, Tab 30].
- E Manitoba Hydro, "Board Recommendation: Route for Bipole III," September 20, 2007; Manitoba Hydro, Briefing Note, "Bipole III - Routing Options," November 23, 2005 (the latter suggests the 2007 estimate would have been approximately $400M without $1.2 billion for converters).
- F Manitoba Hydro, Briefing Note, "Bipole III Conceptual Options," September 30, 2003; PUB Order No. 7/03, p. 18 [Appendix A, Tab 31] (the latter suggests the 2003 estimate would have been approximately $1.3B with $1 billion for converters).
- G 2017/18 GRA, MFR 155, Addendum #04 [Appendix A, Tab 30].
- H Letter from Greg Selinger, then Minister Responsible for Manitoba Hydro, to Vic Schroeder, then Chair of the MHEB, September 20, 2007 [Appendix A, Tab 39].
- I Manitoba Hydro, "Board Recommendation: Route for Bipole III," September 20, 2007.
- J 2017/18 GRA, MFR 155, Addendum #06 [Appendix A, Tab 30]. Note: This estimate was approved by the Vice-Presidents of Transmission and Power Supply, but rejected by the Manitoba Hydro executive and succeeded by a much lower approved estimate: see, e.g., PUB Order No. 59/18, pp. 87-88 [Appendix A, Tab 34].
- K 2017/18 GRA, MFR 154 [Appendix A, Tab 32].
- L See *The Environment Act* Licence No. 3055, August 14, 2013 [Appendix A, Tab 154].
- M NFAT Report, pp. 35, 250 [Appendix A, Tab 15].
- N PUB Order No. 59/18, p. 88 [Appendix A, Tab 34].
- O 2017/18 GRA, MFR 154 [Appendix A, Tab 32].
- P PUB Order No. 69/19, p. 9 [Appendix A, Tab 82].

Finding #1.7: Political considerations were more important than economic considerations in the choice of Bipole III West, which led to a $4.77 billion project that was not the most cost-effective way to achieve reliability. The only options that were seriously considered to solve the reliability need were Bipole III East and Bipole III West. Bipole III East was effectively vetoed by the former Government because of its concerns with opposition by a U.S. environmental organization and some east side First Nations and possible effects on export opportunities in the U.S. due to a damaged reputation, at least the latter of which could not be objectively substantiated.

Finding #1.8: The environmental rationale for building Bipole III on the west side of the Province to preserve the east side area for a UNESCO World Heritage site was undermined by the support for a road through the same area, including the resulting environmental impacts. None of the many documents that the Commission received from the Government included any evidence that the construction of Bipole III through the area would have rendered the achievement of a UNESCO World Heritage site designation impossible, at least with mitigation (e.g., modified routing of Bipole III on the east side to avoid areas of higher value for purposes of the designation).

Finding #1.9: Partnerships with Indigenous peoples on the east side of Lake Winnipeg as part of the Bipole III project were not sufficiently explored by the Government of the day. Options such as equity partnership or meaningful impact benefit agreements would have provided benefits to Indigenous partners on the east side of the Province that could have effectively been paid for by savings from Bipole III East (compared to Bipole III West), while also addressing concerns about impacts of Bipole III on east side Indigenous communities. Instead of exploring partnership – which the Commission heard would have helped reduce or eliminate Indigenous opposition – the Government directed an alternative route and cited Indigenous opposition as a reason for that decision.

Recommendation #1.3: The Government should pursue Indigenous partnerships including equity, means of mitigating project impacts (e.g., modified routing within a preferred corridor), and other means of addressing concerns when a particular project is the most economical way of providing for the supply of power adequate for the needs of the Province, as opposed to rejecting the most economical option out of hand in favour of a more expensive option.

Recommendation #1.4: The Government needs to be aware of and transparent about the incremental costs of constraints and additional requirements that its policies impose on Manitoba Hydro with respect to its projects (e.g., route siting). While it is reasonable to expect a Crown corporation like Manitoba Hydro to adhere to government policies, those policies must be explicit and transparent so that the Government can be properly held accountable for them and their incremental costs. Those policies should be reflected in a policy statement published by the Government.

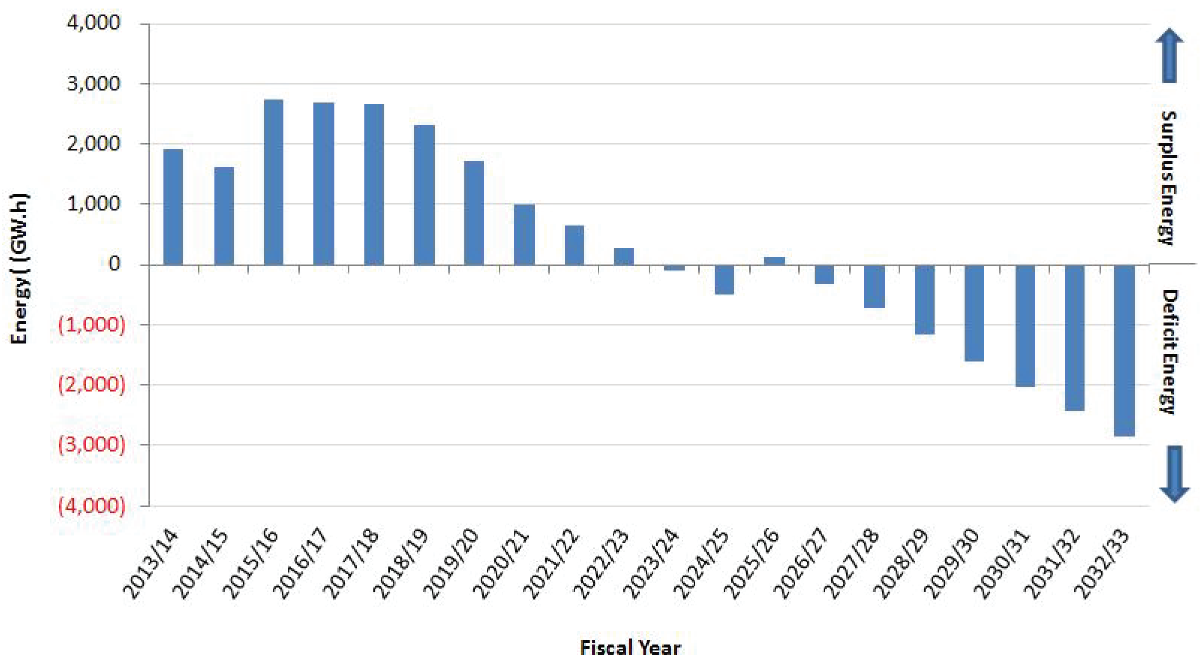
KEEYASK

Manitoba Hydro's Analysis of Need for New Supply to Meet Domestic Demand

Unlike Bipole III, the need for Keeyask was considered during the NFAT. At that time, Keeyask was presented by Manitoba Hydro as a resource option to satisfy the need for new supply resources to meet its expected domestic load and firm export commitments. Manitoba Hydro determined the need for new resources based on a comparison of total demand (domestic load plus firm export commitments) and supply, with new supply being required when demand was projected to exceed existing supply.[88] This assessment considered the fact that almost all of Manitoba's electricity is generated using hydroelectric energy,[89] which means that Manitoba Hydro must have adequate resources to supply the firm energy demand in the event that the lowest recorded coincident water supply conditions are repeated (i.e., "dependable energy").[90]

At the time of its NFAT submission, Manitoba Hydro's analysis (based on 2012 planning assumptions) projected that supply (dependable energy) would be exceeded by demand in or around 2023, as shown in the figure below:[91]

Figure 1 ENERGY BALANCE – DEPENDABLE ENERGY SHOWING DEFICIT BY **2023**



Manitoba Hydro's NFAT submission included analyses based on its 2013 electric load forecast, which estimated Manitoba's energy needs for the 20-year period from 2012/13 to 2032/33. In the 2013 electric load forecast, Manitoba Hydro forecasted domestic peak energy demand growing by 76 MW (1.5%) per year over 20 years. This was significantly higher (almost 58% higher) than the average growth of 44 MW (1.2%) per year during the preceding 20 years.[92]

In March 2014, Manitoba Hydro provided the NFAT Panel with an updated analysis that included new 2013 planning assumptions, new DSM scenarios comprising DSM Levels 1-3, and the prospect of increased load from pipelines.[93] Manitoba Hydro presented several load growth scenarios to

88 Manitoba Hydro, NFAT Submission, Executive Summary, pp. 10, 11 [Appendix A, Tab 44].
89 Canada Energy Regulator, "Provincial and Territorial Energy Profiles – Manitoba" [Appendix A, Tab 45].
90 Manitoba Hydro, NFAT Submission, Chapter 4: The Need for New Resources, p. 38 [Appendix A, Tab 46].
91 Manitoba Hydro, NFAT Submission, Executive Summary, p. 12 [Appendix A, Tab 44]; Manitoba Hydro, NFAT Submission, Chapter 4: The Need for New Resources, p. 48 [Appendix A, Tab 46].
92 Manitoba Hydro, 2013 Electric Load Forecast, p. 39 [Appendix A, Tab 47]. It should be noted that the historical growth rate included the effect of past DSM initiatives, whereas the future growth rate did not.
93 NFAT Report, p. 140 [Appendix A, Tab 15].

determine the domestic need date for new resources based on the various levels of DSM and whether the pipeline load would materialize, as shown below:[94]

Estimated Need for New Resources		
Planning Assumptions	**Need for Dependable Energy**	**Need for Capacity**
2012 Planning Assumption	2022/23	2025/26
2013 Planning Assumption	2023/24	2026/27
NFAT DSM 1	2028/29	2030/31
NFAT DSM 2	2031/32	2031/32
NFAT DSM 2 + increased pipeline load	2024/25	2030/31
NFAT DSM 3	2033/34	2033/34
NFAT DSM 3 + increased pipeline load	2029/30	2030/31

At that time, Manitoba Hydro considered it likely that 1700 GWh of additional load would arise by 2019/20 from upgrades to pipeline pumping stations within Manitoba in connection with Enbridge's Alberta Clipper pipeline, upgrades to Enbridge's Line 3 pipeline, and TC Energy's (then TransCanada) Energy East pipeline project.[95] It also indicated that initiatives approximating DSM Level 2 would be pursued.[96]

The NFAT Panel found that the most plausible scenario drew on the 2013 electric load forecast, including the 1700 GWh pipeline load and DSM level 2 initiatives, and assuming no new exports. It accepted that the need date for new resources would be 2024 based on this scenario, as follows:

> The NFAT Panel is satisfied that Manitoba Hydro's load forecast is reasonable for the short term. It is prudent to assume that the planned pipeline load will materialize, especially in light of the long lead time to construct Keeyask and Manitoba Hydro's obligation to serve domestic load. The NFAT Panel accepts the need date determined by Manitoba Hydro to be 2024, based on the 2013 Load Forecast, DSM Level 2, and the pipeline load.[97]

While the NFAT Panel concluded that new generation would likely not be required until 2024, it nonetheless concluded that there were "compelling economic, financial and commercial reasons" to advance the in-service date for Keeyask to 2019, including to service export contracts.[98] These reasons and their influence on the NFAT Panel's review process are discussed later in this chapter.

The NFAT Panel noted that the biggest short-term uncertainty in Manitoba Hydro's load forecast was whether 1700 GWh of new pipeline load would materialize, which had the potential to change the need date for new resources by a full seven years[99] (i.e., from 2024 to 2031). More than three-quarters of this new pipeline load was introduced by Manitoba Hydro into the need date analysis in March 2014,[100] near the end of the NFAT, through a scenario update "to approximately represent emerging information," rather than a formal update of its load forecast.[101] It is clear from Manitoba Hydro's testimony justifying the pipeline load that it included an amount announced by a pipeline company

94 NFAT, Exhibit MH-95, p. 4 [Appendix A, Tab 48].
95 NFAT Report, pp. 62-63 [Appendix A, Tab 15].
96 NFAT Report, p. 140 [Appendix A, Tab 15].
97 NFAT Report, p. 71 [Appendix A, Tab 15].
98 NFAT Report, p. 20 [Appendix A, Tab 15].
99 NFAT Report, p. 21 [Appendix A, Tab 15].
100 NFAT Report, pp. 140, 201 [Appendix A, Tab 15].
101 2017/18 GRA, Information Request (IR) PUB/MH II-50a [Appendix A, Tab 49].

the week of that testimony (which was neither confirmed nor had regulatory approval) and an amount for the Energy East Pipeline, for which TransCanada had made their initial filing with the National Energy Board that same week (and thus not received regulatory approval).[102]

In the words of Manitoba Hydro's vice-president who first mentioned the new pipeline load during the NFAT testimony, the 1700 GWh amount was a mere "proxy":

> …what we offer is a — just as a proxy is possibly seventeen hundred (1,700). We don't know exactly what the load growth's going to be and -- but that's what we're using currently as a proxy.[103]

The imprecise (and unreliable) nature of the 1700 GWh pipeline load estimate is reinforced by documentation received by the Commission, which indicates that the pipeline load forecast presented during the NFAT included no specific forecast for the Energy East Pipeline.[104] This raises serious questions of how exactly the 1700 GWh "proxy" amount was determined.

Manitoba Hydro also stated during the NFAT that it had advanced the 1700 GWh of pipeline load growth such that it was completely added to the load forecast by 2019/20 (around the desired in-service date for Keeyask), whereas it had previously forecast the same amount of growth over 17 years (i.e., by 2031/32).[105] Like the 1700 GWh load itself, this advancement appears to have been based on last-minute, emerging, and unreliable information that was prone to change.[106]

Finding #1.10: Keeyask was pursued by Manitoba Hydro, recommended for approval by the PUB, and approved by the former Government when it was not necessary at the time to meet the Province's electrical needs. The NFAT Panel concluded that Keeyask would not be needed to meet the Province's needs until 2024 at the earliest, and only if the 1700 GWh of pipeline load materialized. Given the degree of uncertainty surrounding the advanced, last-minute "proxy" pipeline load (much of which was unconfirmed and/or without regulatory approval), it was uncertain at the time whether Keeyask would be needed to meet the Province's electrical needs before 2031.

Finding #1.11: Keeyask was approved and construction on it was commenced for an in-service date of 2019, years before it would be needed to meet the Province's electrical needs, in order to fulfill export contracts. This created a situation in which Keeyask will be built for exports (at least for its initial years of service), which is inherently risky and exposes ratepayers to risks around long-term projections for the export market. If those projections prove optimistic (which the NFAT Panel believed they would, as discussed in Chapter 3), Keeyask may not break even for a very long time and may prove very costly to ratepayers.

Recommendation #1.5: The large and long-term investment in hydroelectric power generation requires the Government to provide guidance to Manitoba Hydro with respect to energy policy. This energy policy should address "merchant plants" if they are to continue being built in the future, including criteria for their commercial evaluation and the extent to which exports (firm and opportunity sales) may drive or advance the development of new generation by Manitoba Hydro.

102 NFAT Report, pp. 62-63 [Appendix A, Tab 15], citing NFAT, Transcript, pp. 1136-1142 [Appendix A, Tab 50].
103 NFAT, Transcript, p. 393 [Appendix A, Tab 51].
104 Manitoba Hydro, "Trans Canada Energy – Energy East Forecast (GWh)," received October 13, 2020.
105 NFAT, Information Request (IR) MIPUG/MH I-043b [Appendix A, Tab 52].
106 2017/18 GRA, Information Request (IR) PUB/MH II-50a [Appendix A, Tab 49].

Variance in Manitoba Hydro's Short-term Forecasts

The 1700 GWh of new pipeline load that Manitoba Hydro predicted during the NFAT never materialized. In its 2014 electric load forecast released in August 2014 (two months after the NFAT Report and one month after government approval of Keeyask), the pipeline load forecast was revised downwards to 655 GWh based on more current information from the pipeline operators – a reduction of more than 60%.[107] This reduction pushed the need date for new resources back by more than four years – all within two months of the NFAT Report. Based on the Commission's review, this revised load forecast did not result in any reconsideration of the need for, or timing of, Keeyask by Manitoba Hydro, the MHEB, the PUB, or the provincial Government.

Since 2014, the pipeline load forecast has further declined and the need date for new resources further delayed. The following table presents Manitoba Hydro's forecast for the pipeline sector in the 2013 scenario update during the NFAT, with the addition of 1700 GWh into the 2016/17, 2017/18, 2018/19, and 2019/20 years.[108] As the table shows, actual pipeline load has been lower than forecasted in the NFAT update and in 2018/19 was approximately half. The future forecast has also been cut in half.[109]

PIPELINE FORECAST COMPARISON (GWh)

	2013 Forecast	2013 Forecast Pipeline Scenario	2014 Forecast	2015 Forecast	2016 Forecast	2017 Forecast	2018 Forecast	2019 Forecast
2013/14	1180	1180	810.4	810.4	810.4	810.4	810.4	810.4
2014/15	1145	1145	1070	1038.0	1038.0	1038.0	1038.0	1038.0
2015/16	1295	1295	1310	1130	1154.2	1154.2	1154.2	1154.2
2016/17	1315	1740	1485	1353	1353	1327.9	1327.9	1327.9
2017/18	1345	2195	1730	1276	1276	1415	1420.7	1420.7
2018/19	1445	2720	1800	1258	1258	1425	1345	1444.6
2019/20	1345	3045	2005	1252	1252	1460	1380	1405
2020/21	1375	3075	2005	1814	1814	1577	1515	1500
2021/22	1385	3085	2005	1806	1806	2007	1515	1500
2022/23	1395	3095	2005	1827	1827	2007	1515	1500
2023/24	1395	3095	2005	1827	1827	2007	1515	1500
2024/25	1395	3095	2005	1833	1833	2007	1515	1500
2025/26	1395	3095	2005	1835	1835	2007	1515	1500
2026/27	1395	3095	2005	1835	1835	2007	1515	1500
2027/28	1395	3095	2005	1835	1835	2007	1515	1500
2028/29	1395	3095	2005	1835	1835	2007	1515	1500
2029/30	1395	3095	2005	1835	1835	2007	1515	1500
2030/31	1395	3095	2005	1835	1835	2007	1515	1500
2031/32	1395	3095	2005	1835	1835	2007	1515	1500
2032/33	1395	3095	2005	1835	1835	2007	1515	1500
2033/34			2005	1835	1835	2007	1515	1500
2034/35				1835	1835	2007	1515	1500
2035/36					1835	2007	1515	1500
2036/37						2007	1515	1500
2037/38							1515	1500
2038/39								1500

Note: shaded values are actuals

Finding #1.12: The pipeline load estimate of 1700 GWh that was introduced near the end of the NFAT was unreasonable. By August 2014 – the month after Keeyask was approved – the estimate was drastically reduced, and the need date for Keeyask deferred by years.

107 PUB Order No. 73/15, p. 71 [Appendix A, Tab 53].

108 2017/18 GRA, Information Request (IR) PUB/MH II-50a [Appendix A, Tab 49].

109 Manitoba Hydro, "Pipeline Forecast Comparison (GWh)," received September 11, 2020.

Recommendation #1.6: Manitoba Hydro, the PUB, and the Government of Manitoba should not respectively pursue, recommend, and approve a multibillion-dollar project based on a need date advanced by multiple years to serve last-minute load forecasted for a small number of customers. If a major project is being built based on a need date to serve load for a small number of customers, that load should be vigorously vetted and verified ahead of time as part of the mandatory public review of such a project (as discussed in other recommendations). The Commissioner notes that Manitoba Hydro's load forecasts include a sensitivity analysis, including around the increase or decrease of one very large industrial customer and that, since the NFAT, Manitoba Hydro has changed the forecasting methodology for potential large industrial load in response to direction from the PUB, resulting in a more conservative methodology and significantly reduced load forecast.

As noted in Chapter 3 of this report, the NFAT Panel also concluded that Manitoba Hydro did not weigh DSM measures equally with other energy options, contrary to best practices, and that an IRP process should have been used. During the NFAT it became clear that significantly higher levels of DSM than originally proposed by Manitoba Hydro were both achievable and economic.[110] An independent expert consultant, LCA, noted that Manitoba Hydro's development plans represented a narrow view of future development and did not fully take advantage of DSM.[111]

As noted above, Manitoba Hydro filed new evidence regarding DSM in March 2014 and indicated that initiatives approximating DSM Level 2 would be pursued, which delayed the need date for new resources. While the NFAT Panel accepted a need date based on DSM Level 2, numerous witnesses suggested Manitoba Hydro could have achieved greater DSM savings and that load growth could have been flattened with DSM, as discussed in Chapter 3 of this report. The NFAT Panel concluded that Manitoba Hydro's DSM analysis "was neither complete, accurate, thorough, reasonable, nor sound."[112]

By the time of the 2017/18 GRA (i.e., three years after the NFAT), Manitoba Hydro anticipated approximately 10 years of flat load growth with DSM,[113] along with an almost 10-year delay to the need date on which Keeyask's approval was based (from 2024 to 2032/33).[114] By November 2018, Manitoba Hydro was forecasting load growth at an average rate of 1.1% per year until 2037/38, excluding DSM,[115] which is lower than the annual minimum of 1.5% DSM savings that have been mandated under *The Efficiency Manitoba Act* and will continue until at least 2035.[116] In other words, with legislated DSM savings, domestic load is not expected to grow until at least 2035 and thus Keeyask will not be needed for the foreseeable future (likely well after 2037/38).

Finding #1.13: If a more accurate, thorough, reasonable, and sound DSM analysis had been incorporated, the need date determined for Keeyask would have been much later and Keeyask likely could not have been justified at the time of the NFAT.

Finding #1.14: The lack of a robust IRP process precluded Manitoba Hydro from effectively weighing DSM and other energy options equally with hydroelectric generation.

110 NFAT Report, pp. 91-92 [Appendix A, Tab 15].
111 NFAT, Exhibit LCA-6, p. 3A-24 [Appendix A, Tab 54].
112 NFAT Report, pp. 91-92 [Appendix A, Tab 15].
113 2017/18 GRA, PUB-42-4, p. 9 [Appendix A, Tab 55].
114 2017/18 GRA, Transcript, p. 1220 [Appendix A, Tab 56].
115 Manitoba Hydro, 2018 Electric Load Forecast, p. 8 [Appendix A, Tab 57].
116 *The Efficiency Manitoba Act*, C.C.S.M. c. E15, ss. 2, 7(1); *Efficiency Manitoba Regulation*, M.R. 119/2019, s. 2. New savings targets are to be established for years beyond 2035, which may be higher or lower than 1.5% per year.

Recommendation #1.7: The Commissioner concurs with the PUB's call for a comprehensive and regularly occurring IRP process in which DSM will be evaluated as a stand-alone resource and placed on an equal footing with other energy resource options. The Commissioner acknowledges that IRP is part of Manitoba Hydro's new management plan, which marks an improvement to the previous resource planning process, and that Bill 35 will mandate IRP.

In the Commissioner's view, this IRP process should be led by Manitoba Hydro based on criteria set by the Government but developed through a public process involving independent experts and overseen by an independent regulator such as the PUB.

During the NFAT, an independent expert consultant, Elenchus Research Associates Inc. ("**Elenchus**"), examined the accuracy of Manitoba Hydro's load forecasts. Elenchus noted in its report that in recent forecasts prior to the NFAT, Manitoba Hydro had been "consistently over forecasting" and that it had overestimated load growth every year, even on a one-year ahead basis, since 2006. It further noted that much of the over-forecasting was attributable to forecasts in the Top Consumers sector[117] – the sector that includes pipelines.[118]

It was similarly noted by Dr. Garland Laliberte during the 2017/18 GRA (on behalf of the Bipole III Coalition) that Manitoba Hydro had been consistently over-forecasting since 2005. Dr. Laliberte noted that between 2005 and 2012 (the most recent eight years for which five-years ahead forecasts were available at the time), Manitoba Hydro's five-year forecasts ranged from 0.1% low to 9.0% high. The forecast that was 0.1% low was the most recent available and was the only one of the eight five-year forecasts that was not high (i.e., the forecasts had previously been high seven years in a row). The forecast that was 9.0% high was the highest of the 21 years for which analyses could be performed and it was from 2013 – the year of Manitoba Hydro's NFAT submission. Dr. Laliberte noted the distortion that inaccurate forecasts cause for resource planning and, in particular, how the forecast that was 9.0% high "signal[led] a need for new resources more than 10 years earlier than they are actually needed," based on an average annual growth rate for gross firm energy of 0.86% at the time.[119] As a further illustration, using a 1.0% growth rate (which is similar to Manitoba Hydro's recent forecasts[120]), a five-year forecast that is 5% too high and a 10-year forecast that is 10% too high signal a need for new resources five and ten years earlier than they are actually needed, respectively.

In its final argument during the 2017/18 GRA, Manitoba Hydro took issue with some aspects of Dr. Laliberte's report, but it did not dispute Dr. Laliberte's analysis of the accuracy of its load forecasts.[121]

The PUB has also questioned the accuracy of Manitoba Hydro's load forecasts, both before and after the NFAT, as shown below:

- Order No. 99/11: "the Corporation identified a projected decline from its 2008 GRA forecast of domestic demand of about 800-1000 GWh. In its 10-year forecast of total domestic base load. Subsequently, and taking into account the slow recovery of industry (in the United States in particular), the closure of a Manitoba pulp and paper plant and the announced future closure of a smelter and refinery in Thompson, it could be argued that MH's domestic load forecast should, or at least could, have been further reduced by 1400-1800 GWh./year."[122]

117 NFAT, Exhibit ERA-6, pp. 37-39 [Appendix A, Tab 58].
118 See, for example, Manitoba Hydro, NFAT Submission, Chapter 4: The Need for New Resources, p. 13 [Appendix A, Tab 46].
119 Dr. Garland Laliberte, "A Review of Manitoba Hydro's Electric Load Forecasting," Presentation to the PUB, January 5, 2018, pp. 9, 11 [Appendix A, Tab 59].
120 Manitoba Hydro, 2018 Electric Load Forecast, p. 4 [Appendix A, Tab 57].
121 2017/18 GRA, Exhibit MH-137, Manitoba Hydro Written Argument, pp. 108-110 [Appendix A, Tab 60].
122 PUB Order No. 99/11, p. 52 [Appendix A, Tab 14]

- Order No. 43/13: "The Board is aware of several recent reports that predict lower electricity demand in the United States. Similarly, the Board is concerned that Manitoba Hydro's projected domestic load growth of 1700 GWh over the next four years is overly optimistic. Manitoba Hydro's projections that 60% of new homeowners will opt for electric heat appears at odds with the utility's Fuel-Switching Report and the low natural gas prices available to homeowners. The utility's projected load growth of 1.5% per year also does not reflect the potential impacts of Demand-Side Management and rising electricity rates."[123]
- Order No. 73/15: "There is evidence that Manitoba Hydro consistently over-estimates the Top Consumers load growth. The first year of each load forecast for the past five years over-estimated the Top Consumers load … The Board recommends that Manitoba Hydro take a more rigorous approach to forecasting the Top Consumers load."[124]

Of particular note from the above examples is the PUB's concern in 2013 that Manitoba Hydro's projected domestic load growth of 1700 GWh over the next four years was overly optimistic. This was one year prior to the NFAT Report, in which the PUB accepted even higher load growth[125] (not including the 1700 GWh of increased pipeline load that the PUB also accepted [126]). The PUB's acknowledgment in 2015 (one year after the NFAT) that Manitoba Hydro consistently overestimated load growth in the Top Consumer sector (which, again, includes pipelines) – as pointed out by Elenchus during the NFAT – is also notable.

During the NFAT, the PUB concluded that methodological concerns raised by parties highlighted the need for more robust forecasting on the part of Manitoba Hydro and that, in future GRAs, it would expect "a more robust forecast to better understand the factors that influence short term fluctuations." The NFAT Panel encouraged Manitoba Hydro to consider the improvements to the load forecasting methodology recommended by Drs. Gotham and Simpson, "as they could provide benefits to the forecasts considered at future rate proceedings."[127]

In the 2017/18 GRA, the PUB recommended further changes to Manitoba Hydro's load forecasting methodology as recommended by independent expert consultants and directed Manitoba Hydro to provide details of the implementation of these recommendations, or reasons for not implementing them, at the next GRA.[128] These recommendations included the use of more negative price elasticities and a substantially larger GDP elasticity,[129] and of scenario analysis to develop alternative load forecasts, stochastic risk assessments,[130] and longer-term data to estimate weather-dependent load.[131] Based on a comparison of Manitoba Hydro's 2016 and 2018 electric load forecasts, it has largely failed to use more negative price elasticities (having only done so for the residential basic sector) and it has not used a substantially larger GDP elasticity,[132] as recommended by the PUB. Manitoba Hydro has also failed to use scenario analysis, stochastic risk assessments, and longer-term data to estimate weather-dependent load,[133] as recommended.

123 PUB Order No. 43/13, p. 36 [Appendix A, Tab 61].
124 PUB Order No. 73/15, pp. 78-79 [Appendix A, Tab 53].
125 Manitoba Hydro, 2013 Electric Load Forecast, p. iii [Appendix A, Tab 47].
126 NFAT Report, pp. 60-61 [Appendix A, Tab 15].
127 NFAT Report, p. 71 [Appendix A, Tab 15].
128 PUB Order No. 59/18, pp. 135-136 [Appendix A, Tab 34].
129 2017/18 GRA, Exhibit AY-1, p. 54 [Appendix A, Tab 62].
130 According to Daymark Energy Advisors, Manitoba Hydro evaluates load uncertainty at P10 and P90 levels based on the overall impact of key input variables on the load variation. A stochastic risk assessment would allow it to estimate potential outcomes through random variation in key input variables based on probabilities optimally identified through sensitivity analysis: 2017/18 GRA, Exhibit DEA-2-1, p. 64 [Appendix A, Tab 63].
131 2017/18 GRA, Exhibit DEA-2-1, p. 64 [Appendix A, Tab 63].
132 Manitoba Hydro, 2016 Electric Load Forecast, p. 57 [Appendix A, Tab 64]; Manitoba Hydro, 2018 Electric Load Forecast, p. 74 [Appendix A, Tab 57].
133 Regarding Manitoba Hydro's continued use of two years of data to estimate weather-dependent load, Manitoba Hydro, 2018 Electric Load Forecast, p. 49 [Appendix A, Tab 57].

Finding #1.15: By the time of the NFAT, Manitoba Hydro had been over-forecasting short-term domestic load growth for years, particularly in the Top Consumers sector which included pipelines. This over-forecasting distorted the need date analysis and resulted in a determination at the time of the NFAT that Keeyask would be needed much earlier than it actually will be.

Recommendation #1.8: The Commissioner agrees that independent expert consultants made useful recommendations during the 2017/18 GRA that Manitoba Hydro should consider implementing into its load forecasting methodology, particularly regarding elasticities, scenario analysis, and use of longer-term data to estimate weather-dependent load. The Commissioner supports the PUB's direction for Manitoba Hydro to provide details of the implementation of these recommendations, or reasons for not implementing them, at the next GRA.

Inherent Unreliability in Manitoba Hydro's Long-term Forecasts

While the NFAT Panel largely accepted Manitoba Hydro's short-term load forecast, it expressed less confidence in Manitoba Hydro's long-term load forecast because Manitoba Hydro did not address the effects of potential structural changes that could greatly increase or decrease demand. An example of a structural change that could increase demand would be the widespread adoption of electric cars. An example of a structural change that could substantially decrease demand would be the electricity produced from a new technology (e.g., solar photovoltaic cells or distributed generation) costing as much or less than electricity from traditional generating technologies used to provide grid-based power, otherwise known as "grid parity."[134]

It was noted in a 2012 internal Manitoba Hydro risk analysis that new technology was a risk to the load forecast. The potential for transformative change was on the list of risks, but there were not any alternative production ideas proposed to mitigate that risk. Grid parity, improvements to the cost of wind generation, and large solar were also identified but discounted.[135]

Another long-term uncertainty identified by the NFAT Panel was the effect of DSM, which had the potential to reduce the overall demand for electricity and which the NFAT Panel noted would likely have a profound impact on Manitoba Hydro's load forecast over the long term.[136]

In the 2017/18 GRA, the PUB found that "any long term load forecast cannot be relied upon, due to the inherent limitations in forecasting the effects and impacts of disruptive technology."[137]

Recommendation #1.9: Given the inherent unreliability in long-term forecasts, projects and development plans should be evaluated using a study period that is significantly shorter than 78 years (the length of the period used during the NFAT). Benefits forecasted over the long term should not be relied upon to justify a project or development plan that does not make sense within a reasonable time frame (e.g., the 35-year detailed analysis period used during the NFAT).

Constraints That Influenced the Outcome of the NFAT Review Process

The NFAT Panel determined that, even with the successful implementation of DSM programs, Manitoba would require "new, long term energy supply" from Keeyask. It "was persuaded by the

134 NFAT Report, pp. 21, 71 [Appendix A, Tab 15].
135 Manitoba Hydro, Finance & Regulatory, "Board Recommendation – 2015 Corporate Risk Management Report," February 2016 [Appendix A, Tab 65].
136 NFAT Report, pp. 21, 72 [Appendix A, Tab 15].
137 PUB Order No. 59/18, p. 135 [Appendix A, Tab 34].

commercial realities of the Keeyask Project, including some $1.2 billion already spent on the Project, as well as the supporting export contracts and the socio-economic benefits from partnership agreements with First Nations."[138]

In addition to the $1.2 billion already spent on Keeyask (as discussed further in Chapter 2 of this report), the NFAT Panel was also influenced by the realities of the following strong indicators of government support for new generation: (i) the partnership between Manitoba Hydro and four First Nations in the form of the JKDA, which the Government supported;[139] (ii) a multibillion-dollar transmission project (Bipole III) that had already been approved and was being built to carry generation from new northern generation;[140] (iii) government approval of export contracts that required new generation to fulfill;[141] and (iv) the Province's 2012 Clean Energy Strategy, which focused on building new hydroelectric generation[142] rather than other resource options considered in the plans during the NFAT (mainly, natural gas fired generation). In addition, the NFAT Panel noted that Manitoba Hydro's economic analysis showed that deferring the in-service date for Keeyask would reduce the project's economics (as discussed in Chapter 3 of this report)[143] and that preserving the 2019 in-service date would avoid having to renegotiate the Keeyask GCC to construct the project and the numerous First Nation agreements already executed.[144] These factors led the NFAT Panel to recommend approval for a 2019 in-service date for Keeyask – five years before it believed that it would be needed domestically.

Finding #1.16: The NFAT Panel's recommendation to approve Keeyask was influenced by key constraints that effectively pre-determined that Keeyask would proceed, including already-executed agreements, $1.2 billion already spent, Bipole III already being built, and the Province's Clean Energy Strategy that favoured new hydroelectric generation. Recommendations addressing these constraints are contained elsewhere in this report.

Finding #1.17: The NFAT Panel recommended Keeyask for approval for an in-service date of 2019 – despite it not being needed until years later – in order to avoid Manitoba Hydro having to renegotiate the GCC and the numerous First Nation agreements that had already been executed. These findings highlight the pitfalls of making material investments and executing complex agreements before a project has been sanctioned, which is addressed in Recommendation #1.10 below. Inferior economics of a deferral scenario was another stated reason for the PUB's recommendation; however, Manitoba Hydro's economic analysis was problematic and alternative generation plans may have been more cost-effective, as discussed in Chapter 3 of this report.

Recommendation #1.10: While it may be reasonable for Manitoba Hydro to negotiate agreements for project construction and agreements with impacted Indigenous groups to establish costs of a project, these contracts should not influence a decision to proceed with a project before it is actually needed or approved. Such agreements should not be executed until after project approval or sanctioning, or if execution occurs beforehand, Manitoba Hydro should ensure that it has the right to terminate the agreement without any material penalty or delay the effective date of the contract if a project is not needed until further in the future. Furthermore, as recommended in more detail in Chapter 2 of this report, limits should be placed on how much advance costs can be spent on a major capital project prior to final approval and sanctioning of that project.

138 NFAT Report, p. 249 [Appendix A, Tab 15].
139 See, for example, the February 9, 2009 recommendations from the Aboriginal Issues Committee of Cabinet that addressed some outstanding First Nations concerns related to the JKDA prior to its execution: Briefing Note, "Aboriginal Issues Committee of Cabinet, Secretariat Analysis", February 2009, p. 2.
140 NFAT Report, p. 27 [Appendix A, Tab 15].
141 NFAT Report, pp. 111, 116 [Appendix A, Tab 15].
142 Manitoba's Clean Energy Strategy, 2012, p. 1 [Appendix A, Tab 66].
143 NFAT Report, p. 27 [Appendix A, Tab 15].
144 NFAT Report, p. 72 [Appendix A, Tab 15].

As discussed elsewhere in this chapter and in Chapter 2, Bipole III was excluded from the NFAT. This represented a further constraint in the NFAT review of Keeyask and its alternatives.

Finding #1.18: Even though Bipole III supported the building of Keeyask, the former Government opposed a review of them together and excluded Bipole III from the scope of the NFAT review of Keeyask. This exclusion biased the analysis in favour of Keeyask, which depended on Bipole III to transmit all its new generation but did not have Bipole III's costs attributed to it during the NFAT.

CHAPTER 2

Government Directions

> *"The west side routing decision for Bipole III was a clear public direction by a former Government that did not reflect the preference of the utility, Manitoba Hydro."*

INTRODUCTION

In accordance with section 2 of the Terms of Reference, the Commission inquired into the extent to which the directions that the Government gave to Manitoba Hydro:

(i) Promoted economy and efficiency in the generation, transmission, distribution, and supply of power in the Province; and

(ii) Resulted in Manitoba Hydro having to address matters beyond its statutory mandate.

This chapter presents the Commissioner's findings and recommendations from this inquiry.

OVERVIEW OF GOVERNMENT DIRECTION

The Bipole III and Keeyask projects were initially conceptualized by Manitoba Hydro, but government direction had a significant influence on their timing and implementation including, most notably, the route of Bipole III (as discussed later in this chapter and throughout this report). This direction took various forms, both direct and indirect, including political rhetoric about "Manitoba's oil" – without which these projects might not have been built to serve exports in advance of a domestic need for new generation. The influence and direction from government had a negative impact on the cost of Bipole III and Keeyask and on economy and efficiency in the generation and transmission of power in Manitoba.

DECISION-MAKING CONTEXT

The direction given to Manitoba Hydro was not limited to project-specific direction. The context in which Manitoba Hydro examined its electric system and determined what projects to pursue was heavily influenced by government action and policy, including policies that constrained and precluded the consideration (at least serious consideration) of alternative solutions.

One example of the constrained decision making context that Manitoba Hydro operated in was the very public view of Manitoba's former Government that hydroelectricity was "Manitoba's oil."[145] This political valuation of hydroelectricity in Manitoba created a context in which hydroelectric generation was the "gold standard" against which every other option would be judged.[146] It at least implicitly encouraged planners at Manitoba Hydro to pursue hydroelectric development and assured them that there would be government support for such projects. For example, the Commission heard from a former executive of Manitoba Hydro that there was pressure from the Government of the day to promote new hydroelectric generation.[147] The former Government's mantra that hydroelectricity was "Manitoba's oil" also endorsed (at least implicitly) the large-scale export of it and the pursuit of projects built to serve the export market (at least partially or initially).[148]

148 Winnipeg Free Press, "Exporting 'Manitoba's oil' down south," May 26, 2011 [Appendix A, Tab 67].

Another example of a constraint on the decision-making context in which Manitoba Hydro operated was the Province's 2012 Clean Energy Strategy. This policy document makes clear the Government's preference for new hydroelectric generation and reducing thermal generation, as evidenced by the following excerpt:

> We recognize that fossil fuels like oil and natural gas will continue to be an important part of our society, but our goal is to reduce our reliance on these imported, greenhouse gas emitting and unpredictably priced commodities sooner rather than later.
>
> Our strategy focuses on building new generation hydro; expanding transmission that improves electricity reliability and security; adding more wind power as economics allow; promoting geothermal, biomass and solar for heating needs; developing our biobased fuels; and leading in new cutting edge electric transportation solutions.[149]

In fact, the very first priority action in the Clean Energy Strategy was building new hydroelectric dams, with Keeyask (and Conawapa) mentioned specifically, and the second priority action included constructing Bipole III and increasing exports, as shown in the excerpt below:[150]

Building New Hydro

- Ensure that the planning, design, consultations and negotiations necessary for developing substantial new hydroelectric generation, including Keeyask (695 MW) and Conawapa (1485 MW), proceed through environmental and economic review. These new generation hydro projects are being designed to greatly reduce environmental impacts and will be developed in partnership with First Nations.
- Improve Manitoba's transmission system reliability, increase export capabilities, and enhance the development of new hydro and wind energy by constructing a new Bipole lll line, expanding interconnections to the US, strengthening the Dorsey convertor station, adding the new Riel Station and advocating for a stronger east-west Canadian grid.

The direct influence of the Clean Energy Strategy on the NFAT (including its priority to build new hydroelectric generation in the form of Keeyask) is made clear by the NFAT Terms of Reference, which required the NFAT Panel to consider the alignment of Keeyask and other resource options with the Clean Energy Strategy.[151]

149 Manitoba's Clean Energy Strategy, 2012, p. 1 [Appendix A, Tab 66].
150 Manitoba's Clean Energy Strategy, 2012, p. 2 [Appendix A, Tab 66].
151 NFAT Terms of Reference, p. 2 [Appendix A, Tab 69].

Finding #2.1: Together, the mantra of "Manitoba's oil" and the policy expressed in the Clean Energy Strategy constrained Manitoba Hydro's decision making by prioritizing new hydroelectricity over other supply options and encouraging the development of projects to serve the export market. These government directions precluded any fair assessment of alternative generation and transmission options which might have promoted more economy and efficiency in the generation and transmission of power in Manitoba, and inexorably moved Keeyask and Bipole III forward. In particular, the Clean Energy Strategy from 2012 (the year before the NFAT began) confirmed that the Government had already decided to proceed with Keeyask. While that decision could have been changed based on the results of the NFAT (as in the case of Conawapa), there was a high threshold to do so, given the requirement for an alternative to align with the Clean Energy Strategy which prioritized new hydroelectric generation over other supply options.

Project Labour Agreements

Since the 1960s, Manitoba Hydro has been a party to the Burntwood Nelson Agreement where a coalition of 17 unions representing construction and trade workers have the exclusive right to supply labour to any new hydroelectric project on the Burntwood or Nelson River.[152] The agreement requires individuals who work on the projects to join, and pay dues to, one of the unions that is a party to the agreement.[153]

While it is largely outside the scope of this inquiry, some literature has suggested that unions raise the cost of labour by increasing wages above market rates and impose other costs on employers, such as by limiting discretion in hiring and firing and altering the structure of pay differentials across skill groups.[154] It has also been suggested that a monopoly on labour (such as project labour agreements requirements for Bipole III and Keeyask workers to belong to a select union) often leads to cost overruns and delays on large-scale public infrastructure projects.[155]

Finding #2.2: Project labour agreements constrained Manitoba Hydro when tendering work for Bipole III and Keeyask. They required Manitoba Hydro to employ labour from select unions, which may have resulted in higher project costs.

The Manitoba Hydro Act

The *Manitoba Hydro Act* states that "[n]o person other than the corporation [Manitoba Hydro] shall engage in the retail supply of power in Manitoba."[156] This precludes private companies from participating in the Manitoba retail electricity market and gives Manitoba Hydro a monopoly. If competition improves service and price (as it has been shown to[157]), then this restriction on competition is inhibiting improved service and price in Manitoba's retail electricity market.

Regarding wholesale electricity exports, the Commission understands that there is no prohibition on companies other than Manitoba Hydro building new generation in Manitoba for export (i.e., merchant plants). However, in order for other companies to build new generation in Manitoba for export, they need access to competitively priced transmission in the Province so that the power they generate can be transmitted out of the Province and sold at a competitive price. The Commission heard during the

152 Manitoba Building Trades, "Allied Hydro Council" [Appendix A, Tab 70]; Manitoba Hydro, "The Burntwood/Nelson River Agreement" [Appendix A, Tab 71].
153 See, for example, *Millen et al. v. Hydro Electric Board (Man.)*, 2016 MBCA 56 at para. 6.
154 See, for example, John DiNardo & David S. Lee, "Do Unions Cause Business Failures?", March 2003, Unpublished Working Paper, U.C.-Berkeley Department of Economics, p. 1 [Appendix A, Tab 72].
155 Progressive Contractors Association, "Manitoba's Outdated Labour Laws," August 2, 2016 [Appendix A, Tab 73].
156 *The Manitoba Hydro Act*, C.C.S.M. c. H190, s. 15.2.
157 See, for example, Karen Ellis & Rohit Singh, "The Economic Impact of Competition," Overseas Development Institute Project Briefings No. 42, July 2010 [Appendix A, Tab 74].

interviews that transmission tariffs and Manitoba Hydro's control of access to transmission effectively preclude export projects by other companies.[158]

Finding #2.3: The current policy in Manitoba allows for companies other than Manitoba Hydro to build new generation in Manitoba for export, but there is little evidence that any are doing so on a significant scale. Transmission tariffs and Manitoba Hydro's control of access to transmission may be limiting their ability to do so.

Recommendation #2.1: The Government should commission an independent review and public report regarding transmission tariffs, access to transmission in the Province, and related government policies to ensure that they are not a barrier to other companies building new generation in Manitoba for export, in accordance with its policy of allowing same. Fostering competition for merchant plants will likely drive efficiencies and cost reductions for all such projects, including those pursued by Manitoba Hydro.

Constraints on Project Structure

Manitoba Hydro was constrained in its development of the projects from considering alternative structures to the classic design/build/own path followed in its previous projects. It is at least arguable that the risky nature of large hydroelectric dams supported by time-limited export agreements should have caused decision makers at Manitoba Hydro to consider other structures for Keeyask and perhaps for Bipole III. For example, a P3 model could have been considered that would have transferred risk to the private partner and introduced clear accountability to the project as it proceeded. P3 project structures have been used by governments across Canada and, when skillfully designed, can protect the public purse from costs and risks that often arise during construction of large infrastructure.[159]

As described by PPP Canada, P3s are a long-term performance-based approach for procuring public infrastructure where the private sector assumes a major share of the responsibility in terms of risk and financing for the delivery and the performance of the infrastructure, from design and structural planning, to long-term maintenance. The benefits of P3s include the fact that they put private sector capital at risk, rather than taxpayers' or ratepayers' money, which PPP Canada explains as follows:

> Most importantly, P3 projects require private sector capital to be at risk. The public sector pays only when the infrastructure is available and performs. This generally means that no payments are made until the infrastructure is built and a substantial portion is paid over the life of the asset, if it is properly maintained and performs. This "skin in the game" means that taxpayers are not on the financial hook for cost overruns, delays or any performance issues over the assets life. It also means that the profit motive is harnessed to ensure effective results. Finally, this requires the private sector to raise both equity and debt capital, meaning that there is substantial oversight by lenders and investors in both the upfront due diligence and project execution. This is a discipline that the public sector cannot match.[160]

One example of a recent P3 project is a new mental health hospital constructed in North Battleford, Saskatchewan that was designed to replace a 100-year-old structure. This project encountered problems both during construction and after commissioning (water issues and roofing problems), but those problems came at the expense of the private partner and not the public partner under the

158 Information received from participant, July 15, 2020.
159 See, for example, PPP Canada, "The Benefits of P3s" [Appendix A, Tab 75].
160 See, for example, PPP Canada, "The Benefits of P3s" [Appendix A, Tab 75].

P3 arrangement. Cost certainty was achieved from the public's perspective and accountability for the problems on the project was clear.[161]

Other examples of P3 projects include schools and ring roads in Alberta. Since 2008, 40 new schools have been built in Alberta under P3 contracts in three different phases. By using a P3 to design, build, finance, and maintain those 40 schools, the Government of Alberta expects to save $245 million over 32 years.[162] Similarly, using a P3 model to design, build, finance, and operate parts of the Calgary and Edmonton ring roads is expected to save the Government of Alberta $1.434 billion over approximately 34 years.[163]

Consideration of a P3 project structure was effectively opposed by the former Government in 2012 with the introduction of The Public Private Partnerships Transparency and Accountability Act, which created an onerous process that had to be followed to pursue P3 projects.[164]

Former Premier Greg Selinger, when he was the Minister Responsible for Manitoba Hydro, publicly stated that P3 arrangements were "a back-door route to privatization" and cost "more money because the borrowing costs are higher."[165]

While it is true that borrowing costs may be higher under a P3 arrangement because of the relative strength of the Province's credit rating, there are other considerations that might make a P3 model a better option, nonetheless. As noted above, one key consideration is the allocation of risk to the private partner under a P3 arrangement, rather than to the public partner and, by extension, the public. If any significant allocated risk is realized, a P3 arrangement may cost ratepayers less than a traditional design/build/own option, regardless of the higher borrowing costs.

Based on the above directions from Government, it is possible that the notion of pursuing Keeyask or Bipole III using a P3 model did not even occur to Manitoba Hydro as it had been effectively precluded by the Government. Certainly, the evidence demonstrates that a P3 option for Keeyask or Bipole III never received serious consideration within Manitoba Hydro or the Government.

The failure to use a P3 model in which private sector capital was at risk for cost overruns on Keeyask resulted in those overruns being borne by ratepayers, which are currently estimated at $2.2 billion (based on a current estimate of $8.7 billion[166] compared to the $6.5 billion pre-construction estimate[167]).

In addition to a possible P3 model, Manitoba Hydro does not appear to have seriously considered Indigenous partnership options for Bipole III that could have allowed the project to proceed on

161 See, for example, Saskatoon StarPhoenix, "Two months after opening, Saskatchewan Hospital North Battleford needs entire roof replacement," May 22, 2019 [Appendix A, Tab 76].

162 Government of Alberta, "P3 Value for Money Assessment and Project Report – Alberta Schools Alternative Procurement (ASAP) Project Phase 1," June 2010, p. 3 [Appendix A, Tab 77]; Government of Alberta," P3 Value for Money Assessment and Project Report – Alberta Schools Alternative Procurement (ASAP) Project Phase II," September 2010, p. 3 [Appendix A, Tab 78]; Government of Alberta, "P3 Value for Money Assessment and Project Report – Alberta Schools Alternative Procurement (ASAP) Project Phase III," March 2013, p. 3 [Appendix A, Tab 79].

163 Government of Alberta, "P3 Value for Money Assessment and Project Report – Southeast Stoney Trail (SEST) Ring Road Project," September 2010, p. 3 [Appendix A, Tab 80]; Government of Alberta, "P3 Value for Money Assessment and Project Report – Northeast Anthony Henday Drive (NEAHD) Ring Road Project," November 2012, p. 3 [Appendix A, Tab 81].

164 *The Public Private Partnerships Transparency and Accountability Act*, C.C.S.M. c. P245 required a public sector entity to: (i) have comparative analysis prepared of the P3 option and the traditional design/build/own option in accordance with the regulations and prepare a report of that analysis and the expected results; (ii) make the analysis and comparison report publicly available for comment; (iii) appoint a fairness monitor to oversee the procurement process and prepare a report to be reviewed by the Auditor General; (iv) report on the results of the project, in accordance with the regulations, both at the end of the project and every four years (if applicable), which were then to be reviewed by the Auditor General; and (v) respond to any recommendations from the Auditor General based on a report from the fairness monitor or the public sector entity.

165 Winnipeg Sun, "Tories open to private-sector Hydro deals," November 13, 2006 [Appendix A, Tab 25].

166 See, for example, PUB Order No. 69/19, p. 17 [Appendix A, Tab 82].

167 See, for example, NFAT Report, p. 30 [Appendix A, Tab 15].

the east side of the Province. Documentation received from the Government indicates that the Government of the day was opposed to equity partnerships on the basis that they could be confused with privatization, which was contrary to government policy.[168]

Finding #2.4: The former Government's ideological aversion to P3s precluded the consideration of a P3 model to allocate the risk of the projects among those involved in their construction. Cost overruns from the time of approval for Bipole III ($1.49 billion), Keeyask ($2.2 billion), and Wuskwatim ($400 million) alone suggest that the current design/build/own model is not working properly and not reasonably minimizing risks and costs for ratepayers. The former Government's ideology also precluded the consideration of an equity option for Indigenous groups along the east side route of Bipole III – the route that Manitoba Hydro preferred for reasons including cost and reliability. The construction of Bipole III East with an equity option for Indigenous groups could have reduced construction costs for Manitoba Hydro (and, ultimately, ratepayers) and reduced the financial exposure of the Province, while also providing equity and financial opportunities for Indigenous partners.

Recommendation #2.2: The Government of Manitoba and Manitoba Hydro should consider P3 arrangements for any future high-value capital projects. Under a P3 model, the allocation of risk and cost overruns to the private partner(s) on a project like Keeyask may make this option more favourable than the classic design/build/own model. Keeyask has experienced significant cost overruns and delays like many other public infrastructure projects, at least in part because Manitoba Hydro is not a construction manager. By contrast, cost overruns and delays are less common on P3 projects, in which risks and responsibilities are allocated to the private sector based on its areas of expertise (e.g., construction management). Such a P3 arrangement could include a takeout option in the future and help avoid multibillion-dollar cost overruns in the future.

Recommendation #2.3: The Government should be open to equity options or other opportunities with Indigenous partners for all activities, including transmission projects like Bipole III. In addition to helping to fulfill the goal of reconciliation, such partnerships with Indigenous peoples may help to ensure that projects can be completed on schedule and on budget by allowing Manitoba Hydro to proceed with its preferred development option without delays caused by Indigenous opposition.

BIPOLE III

Routing

The west side routing decision for Bipole III was a clear public direction by a former Government that did not reflect the preference of the utility, Manitoba Hydro[169] (as discussed in the previous chapter). This direction from government to Manitoba Hydro was unprecedented and prompted a request from the MHEB to the Government to formalize their instructions.[170] Those formalized instructions came in the form of the September 2007 letter from then-Minister Selinger.[171] The Commission heard that this letter was delivered at the request of the MHEB to "get them off the hook."[172] The President and CEO of Manitoba Hydro at the time of Bipole III's licensing approval previously stated during an interview with the Crown Corporation Council as part of its annual review of Manitoba Hydro that the approved

168 Manitoba Hydro Submission to Cabinet, "Cree Nation Partnerships in Future Hydroelectric Projects," May 9, 2001.
169 2017/18 GRA, PUB Minimum Filing Requirement (MFR) 155, Addendum #04 [Appendix A, Tab 30].
170 Briefing Note, Department of Finance, "Meeting with Manitoba Hydro," July 10, 2007, p. 2.
171 Letter from Greg Selinger, then Minister Responsible for Manitoba Hydro, to Vic Schroeder, then Chair of the MHEB, September 20, 2007 [Appendix A, Tab 39].
172 Information received from participant, February 18, 2020.

Bipole III project (Bipole III West) was not Manitoba Hydro's choice,[173] implying that it was instead the choice of Government.

Finding #2.5: The elimination of a Bipole III East option was a clear direction from the Government that did not promote economy and efficiency in the generation, transmission, and distribution and supply of power in the Province. It also eliminated an option to engage Indigenous peoples along the east route as equity partners in Bipole III, which might have helped earn their support. As discussed elsewhere in this report, this government direction introduced significant cost increases, complexity, and risks for the Bipole III project.

Exclusion from the NFAT

As discussed in Chapter 1 of this report, the former Government specifically excluded Bipole III from the NFAT Terms of Reference[174] and it was made clear to various expert witnesses that Bipole III was not to be part of their analysis for the NFAT. This direction had a significant impact on the analysis of the PDP considered in the NFAT because it caused Bipole III to be treated as a sunk cost in every scenario (including scenarios where Bipole III was not required), thus skewing the analysis.[175]

The PUB commented on this during the NFAT, and afterwards. During the NFAT, the PUB commented on the treatment of the costs of Bipole III as sunk costs by summarizing concerns with such treatment that were identified by Whitfield Russell Associates ("**WRA**"), as follows:

> Whitfield Russell identified the treatment of costs associated with Bipole III as a particular concern. This witness was of the view that the costs of Bipole III were not sunk costs because the facility is yet to be built. Whitfield Russell further suggested that including Bipole III's costs as a common cost biases the economic analysis in favour of the hydro-based plans. In this witness's opinion, Bipole III should not be treated as a neutral factor in assessing all of the development plans because not all of the plans require its construction. Consequently, Bipole III's costs should be considered as a cost attributable to the hydro-based plans rather than to the system as a whole.[176]

While the PUB did not comment further on the treatment of Bipole III costs as sunk costs during the NFAT, it did comment during the 2017/18 GRA about how the exclusion of sunk costs (as was done with the Bipole III costs during the NFAT) "can distort the comparison of the project with alternatives,"[177] similar to the concern raised by WRA during the NFAT and summarized above.

The Commission similarly heard during interviews that Bipole III's exclusion from the NFAT affected the analysis of the Keeyask project and influenced the decision of the NFAT Panel to recommend Keeyask for approval.[178]

The exclusion of Bipole III from the NFAT was a curious action by the former Government, apparently taken based on the rationale that it was needed for reliability.[179] In its 2016 report, BCG noted that Bipole III and Keeyask should have been evaluated together along with the tie-line, instead of individually, to properly assess the collective risks of conducting all the projects at once. It noted that

173 Crown Corporation Council, Interview with Scott Thomson, July 22, 2014.
174 NFAT Terms of Reference, p. 2 [Appendix A, Tab 69].
175 Information received from participant, April 17, 2020.
176 NFAT Report, p. 158 [Appendix A, Tab 15].
177 PUB Order No. 59/18, p. 251 [Appendix A, Tab 34].
178 Information received from participant, April 17, 2020.
179 See, for example, Winnipeg Free Press, "Shocking exclusion," May 25, 2013 [Appendix A, Tab 83].

Keeyask (and the tie-line) were dependent on construction of Bipole III and that "separate reviews of the projects were not the best choice given their inherently interconnected nature."[180]

Finding #2.6: Bipole III and Keeyask should have been evaluated together given their inherently interconnected nature. If they were considered together, and Bipole III and its alternatives were included in the NFAT, the costs of Bipole III would not have been treated as a common cost to all plans and some plans may have included a different reliability option.

Finding #2.7: The former Government's decision to exclude Bipole III from the NFAT caused the review to be incomplete and skewed the results of the process. Expert witnesses were prevented from considering Bipole III as anything other than a "sunk cost," which skewed the economic analysis of Keeyask and unfairly favoured plans that required Bipole III relative to alternative options that did not (as discussed in Chapter 3 of this report).

Recommendation #2.4: The Commissioner believes that the requirement in Bill 35 for public review and Cabinet approval of any new power generating station with a peak capacity of at least 200 MW, and any new transmission with a voltage of at least 230 kV, that will require an investment by Manitoba Hydro of $200 million or more, is reasonable. However, the Commissioner would propose that this mandatory public review should include an evaluation of any other new project or facility upon which the new generating station or transmission line is dependent (in the way that Keeyask was dependent on Bipole III to transmit power that it produces).

KEEYASK

Approval of the KIP

The Keeyask project had three components: the 695 MW generation station, the Keeyask transmission project, and the KIP.[181] The KIP involved the construction of the preparatory support infrastructure required to construct the generation station and included construction of roads and work camps.[182] This infrastructure work was separately licensed and approved in advance of the rest of the Keeyask project.[183] It began in early 2012 and was completed in July 2014, one month after the NFAT Report was released.[184]

Based on a 2010 Cabinet briefing note provided to the Commission, it appears that discussions about the KIP formally began in 2009 and that the goal of the project was to protect against construction delays (as experienced on Wuskwatim) and risks to export sales, and to advance and increase opportunities for Indigenous employment and construction contracts.[185]

The Cabinet briefing note indicates that in 2010 the MHEB was contemplating cancelling plans to move forward with the KIP and delaying the Keeyask generation station by at least one year, due to a reluctance to commit significant capital for it in advance of having final export contracts negotiated. The briefing note outlined several negative consequences of delaying Keeyask, including on power sales to the U.S. It recommended that the issue be discussed with Manitoba Hydro at the earliest opportunity.[186]

180 BCG, "Review of Bipole III, Keeyask and Tie-Line Project," September 19, 2016, p. 2 [Appendix A, Tab 22].
181 NFAT Report, p. 119 [Appendix A, Tab 15].
182 Keeyask Hydropower Limited Partnership, "Keeyask Infrastructure Project" [Appendix A, Tab 84].
183 NFAT, Transcript, p. 20 [Appendix A, Tab 85].
184 Keeyask Hydropower Limited Partnership, "Keeyask Infrastructure Project" [Appendix A, Tab 84].
185 Briefing Note, Department of Finance, "Potential for Keeyask Delays and Negative Consequences," April 16, 2010.
186 Briefing Note, Department of Finance, "Potential for Keeyask Delays and Negative Consequences," April 16, 2010.

The subsequent licensing and approval of the KIP marked a change in government policy. A 2008 Cabinet briefing note clearly states that an earlier, separate licence for early components of Keeyask such as roads and camps was not allowed under provincial policy at the time. However, the 2008 briefing note suggested that a change in policy could be considered to advance the project in-service date and provide Indigenous jobs and economic benefits.[187] These reasons are similar to those in the 2010 Cabinet briefing note highlighting the merits of proceeding with the KIP in advance of Keeyask being approved.

Finding #2.8: Based on the indication in a briefing note that there would be negative consequences of delaying Keeyask if the MHEB cancelled plans to move forward with the KIP (as it was contemplating in 2010), and the fact that the KIP was not cancelled, it appears that the former Government did not want the Keeyask project delayed and it influenced Manitoba Hydro's decision to proceed with the KIP. It also appears that the MHEB was very much doing its job in canvassing the option of pausing Keeyask without clear evidence of power sales. It is apparent that Cabinet rejected this advice and pushed forward and licensed the KIP despite prior government policy which did not permit such earlier, separate licensing.

Finding #2.9: The approval of the KIP and associated funding in 2012 (in advance of the NFAT and approval of the rest of the Keeyask project) was a form of direction that the Government gave to Manitoba Hydro. It signaled the Government's support for Keeyask even prior to the start of the NFAT and the formal approval of the project. This approval also resulted in the expenditure of a significant portion of the $1.2 billion in sunk costs that were spent on Keeyask prior to the start of the NFAT, and which in turn influenced the NFAT Panel in its recommendation to proceed with Keeyask (as discussed in Chapter 1 of this report).

Recommendation #2.5: Limits should be placed on how much advance costs can be spent on a major capital project prior to final approval and sanctioning of that project. The only costs that should be incurred prior to a major project's approval are for activities required to assess the merits of the project (such as preliminary engineering and environmental work, Indigenous engagement, and, in some cases, costs to negotiate material agreements provided that the agreements can be cancelled if the project does not proceed – as discussed in Chapter 1). Prior to the major project being approved, costs should not be incurred that unnecessarily constrain the subsequent decision-making process.

Generation Tied to Exports

The Commission heard during interviews that the former Government would not have proceeded with Keeyask without export contracts to support it.[188] Export contracts with Minnesota Power ("**MP**") and the Wisconsin Public Service ("**WPS**") were approved by the former Government in August 2011 and were set to begin in 2020.[189] The order in council approving these contracts specifically acknowledged that the construction of new hydroelectric power generation and transmission facilities in Manitoba would be necessary for Manitoba Hydro to fulfill its commitments under the contracts.[190] By approving these export contracts (particularly with this acknowledgment), the former Government all but assured the approval of associated generation and transmission projects (i.e., Keeyask and Bipole III), the PUB and other due diligence processes notwithstanding. The former Government surely would not have approved the export contracts if it did not think that they should be fulfilled, which required new

187 Briefing Note, Manitoba Justice, "Keeyask Project Development Agreement Completed," June 27, 2008.
188 Information received from participant, March 24, 2020.
189 NFAT Report, p. 109 [Appendix A, Tab 15].
190 Order in Council 304/2011 [Appendix A, Tab 9].

generation. Failure to fulfill the contracts would have risked Manitoba Hydro's commercial reputation, as it argued during the NFAT in favour of approval for Keeyask.[191]

A Government of Manitoba news release from 2011 states that then-Premier Greg Selinger announced the signing of the MP and WPS export contracts by Manitoba Hydro and indicates that he said they would trigger the development of Keeyask, as follows:

> The premier said these sales will require the construction of new hydroelectric generating capacity in Manitoba. They will trigger the development of the 695-MW Keeyask (Cree for gull) Generating Station located on the lower Nelson River 175 km northeast of Thompson in the Split Lake Resource Management Area. Keeyask is to be developed by a partnership consisting of Manitoba Hydro and the Keeyask Cree Nations-Tataskweyak Cree Nation, War Lake First Nation, Fox Lake Cree Nation, and York Factory First Nation. The $5.6-billion project will provide some 4,500 person-years of construction employment, said Selinger.
>
> "I am very pleased that Manitoba Hydro is moving forward with these power sales which will significantly increase our exports and lead to further development of Manitoba's renewable hydro power resources," stated Selinger. "These sales will add to Manitoba's reputation as a sustainable energy leader and help reduce global greenhouse-gas emissions by reducing the need for thermal generation in the United States. At the same time, the development of Keeyask will deliver jobs, training and business opportunities to the Keeyask Cree Nations, the north and all of Manitoba."[192]

Finding #2.10: The approval of export contracts set to begin in 2020, on the understanding that new hydroelectric generation and transmission was required to serve them, created an imperative for new generation and transmission to be built and operational by 2020. This imperative constrained the decision making of both Manitoba Hydro and the NFAT Panel.

Recommendation #2.6: Manitoba Hydro's ratepayers should not bear the risk associated with new generation projects that will, for an extended period of time, be commercial in nature, used for exports, and not needed to serve domestic demand. In other words, they should not be used as involuntary equity investors for projects to serve export demand in a risky market. Since it is the Government that approves export contracts and new generation projects like Keeyask, not ratepayers, and the Government that benefits (through water rentals, capital taxes and debt guarantee fees from Manitoba Hydro) even if such projects do not turn out well financially (as discussed in Chapter 4), it is the Government that should bear this risk. Accordingly, if a Government in the future approves a generation project that is, for an extended period of time, primarily for export and not needed for domestic demand, then the Government should bear the risk if this commercial plant is not successful during that period. If the market plan fails and export revenues do not cover the costs of operating the plant during that period and the proportion of capital costs for that part of the plant's operating life, then the Government should reduce or suspend its collection of transfers from Manitoba Hydro until those cost shortfalls are made up. This will have the effect of putting government's budget at risk for decisions that are made by Government, rather than ratepayers.

The Commissioner believes that this recommendation will add accountability that will improve decision making at the government level and will provide a proper incentive to the Government of Manitoba to provide greater oversight and accountability with respect to any future major capital projects.

To implement this recommendation, Government may wish to legislate a reduction or suspension in the transfers that Manitoba Hydro is required to pay to the Government in the circumstances set out above.

191 NFAT, Exhibit MH-204, Manitoba Hydro Final Argument, pp. 285-286 [Appendix A, Tab 18].

192 Government of Manitoba, News Release, "$4 billion in power sales to U.S. for Manitoba Hydro: Selinger," May 25, 2011 [Appendix A, Tab 86].

Recommendation #2.7: As recommended in Chapter 1 of this report, the Government should develop new policy regarding merchant plants that includes evaluating the commercial merits (i.e., profit potential) of those projects differently than projects built to serve domestic demand. In addition, the Government should develop new policy regarding the extent to which exports should drive or advance the development of new generation by Manitoba Hydro. This policy should address how much of those exports should be supported by firm sales agreements (as opposed to opportunity sales).

LACK OF GOVERNMENT DIRECTION AND OVERSIGHT

There were areas where government direction would have assisted Manitoba Hydro and promoted economy and efficiency in the generation, transmission, distribution, and supply of power in the Province, but the Government failed to provide such direction.

For example, through interviews and review of documents from the Government and Manitoba Hydro, there was no indication that the former Government subjected the capital plans of Manitoba Hydro to a comprehensive review by Treasury Board or any body other than the PUB. This lack of oversight on the part of the Government effectively left questions of public debt, risk to the Province's credit rating, and a thorough economic review to the PUB, which only had an assessment role with respect to Keeyask in the later stages of the project. This approval was sought after $1.2 billion had already been spent and the Government had already indicated its support for the project, including in the Clean Energy Strategy and through the approval of the KIP.

Further, the Government's lack of direction following significant cost overruns with the Wuskwatim project (which was completed in 2012 at a cost of $1.3 billion,[193] which was 44% higher than planned at the time of its review by the CEC in 2003[194]) signalled either a lack of understanding of the financial implications of consistent under-budgeting by Manitoba Hydro, or a lack of interest in either the impact of the higher cost or the message that this sent to the management and staff of Manitoba Hydro. Accountability will be dealt with in other parts of this report, but Government's lack of direction gave no indication to Manitoba Hydro's management that they would be accountable for their decisions.

Finding #2.11: The lack of government direction through the absence of a substantive review by the Treasury Board Secretariat of Manitoba Hydro's capital plans exposed the Province to undue risk without appropriate oversight with respect to the financial health of the Province.

Recommendation #2.8: Treasury Board should continue to monitor the financial health of Manitoba Hydro. This should include the continued review of Manitoba Hydro's annual operating and capital budgets against financial targets set by the Government. This would provide the Government with an oversight process involving its financial experts reviewing these plans and advising the Government on their financial implications for the Province and, by extension, the public.

193 Wuskatim Power Limited Partnership, "About The Wuskwatim Generating Station" [Appendix A, Tab 87].
194 PUB Order No. 99/11, p. 29 [Appendix A, Tab 14].

Recommendation #2.9: Government should strengthen its internal oversight processes to ensure Cabinet is fully aware, on an ongoing basis, of the need, benefits, and risks of Manitoba Hydro capital projects. The intent would be to assess projects proposed by Manitoba Hydro before public regulatory bodies review them. This would likely require additional resources with the capacity to understand complex economic and technical energy matters. The benefits of such a measure would significantly outweigh the costs given the magnitude of the impacts mega-projects have on the provincial economy.

For example, the Crown Services Secretariat could assess the rationale for the need for new generation and transmission and confirm options that have been comprehensively considered.

Another example of a lack of government direction and oversight was with respect to Manitoba Hydro's DSM plan. At the time of the NFAT, Manitoba Hydro was required to prepare a three-year DSM plan on an annual basis in consultation with the Government, pursuant to *The Energy Savings Act*.[195] This was the mechanism through which the former Government exercised oversight and approval of Manitoba Hydro's DSM plan. As discussed elsewhere in Chapter 1, DSM projections and resulting load forecasts underpinned the need date for Keeyask.

The Commission neither reviewed nor heard any evidence that the Government analyzed Manitoba Hydro's DSM plan which influenced the load forecast and need date during the NFAT, rather than simply "rubber stamping" it.

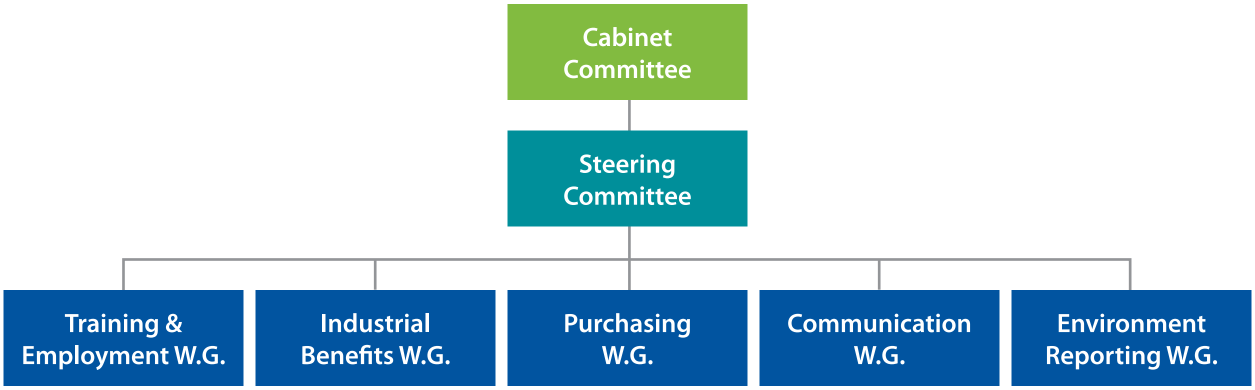
Finding #2.12: The Government's failure to analyze Manitoba Hydro's DSM plan prior to the NFAT represented a lack of government direction and oversight. Government direction and oversight in the form of analyzing Manitoba Hydro's DSM plan might have led to a more ambitious (and realistic) DSM plan and reduced its load forecast, and thus delayed the need date for Keeyask based on that forecast. As discussed in Chapters 1 and 3 of this report, significantly higher levels of DSM post-NFAT have contributed to a flattened load forecast and a more than ten-year delay in the domestic need date for Keeyask.

GOVERNMENT MANAGEMENT STRUCTURES

During the 1990s[196] and into part of the 2000s,[197] the Government of Manitoba was pursuing a long-term power sales contract with Ontario and planned to build Conawapa to provide the necessary electricity. In anticipation of the Conawapa project, the Government created a formal management structure within government to manage the project and focus resources on it. This management structure consisted of:

1. A Cabinet Committee to oversee preparations related to Conawapa;
2. A Steering Committee (consisting of the Chair of the Manitoba Energy Authority and the MHEB, the CEOs of the Manitoba Energy Authority and Manitoba Hydro, and numerous deputy ministers), with the role of:
   a. coordinating and providing direction to the working groups; and
   b. facilitating communications between:
      i. government departments and Manitoba Hydro; and
      ii. the Cabinet Committee and the working groups; and
3. The five working groups ("**W.G.**") shown in the diagram below.[198]

195 NFAT Report, pp. 22, 74, 93 [Appendix A, Tab 15].
196 Manitoba Hydro, System Planning, "Bipole III: Past, Present and Future," Presentation at the 2019 Minnesota Power Systems Conference, November 13, 2019, p. 13 [Appendix A, Tab 36].
197 Manitoba Hydro, Transmission & Distribution, "Board Discussion Item, Bipole III Corridor," August 12, 2004; Briefing Note, Department of Finance, "Bipole III - Routing Options," November 23, 2005.
198 Manitoba Energy Authority, "Discussion Paper: Manitoba Hydro-Developments Conawapa/Bi-Pile 3 Projects," January 1990.



While the sale to Ontario did not materialize, this structure appears to be sufficiently robust and broad-based to provide the kind of oversight and direction that would help ensure the success of any major project. However, this process was not used for Keeyask.

For the Keeyask project, the Government appears to have left substantive government oversight to the Priorities and Planning Committee of Cabinet.[199] There were insufficient processes and mechanisms that formally incorporated professional oversight from Treasury Board[200] or resources from other government departments, which could have enhanced the oversight and direction to help ensure that the project was successful.

The Government trusted the MHEB to provide the oversight and direction required to make decisions for Manitoba Hydro that had (and continue to have) material adverse effects on the financial health of the Government of Manitoba. The lack of oversight by government allowed the projects to become firmly established and entrenched long before they were subjected to an independent review at which point – given the sunk costs and executed agreements – they were effectively a *fait accompli*.

Finding #2.13: A more robust structure that formally incorporated professional oversight from Treasury Board and resources from other government departments would have enhanced the oversight and direction to help ensure a more complete evaluation of Keeyask.

Recommendation #2.10: For any future major capital project like Keeyask or Conawapa, the Government should create a formal management structure to oversee the project, similar to what was put in place for Conawapa in the 1990s. Within that structure, there was involvement at all levels from various ministries (including the Ministry of Industry, Trade and Tourism that existed at the time). If such a structure is used on a major capital project that is underpinned by export contracts to the U.S., like Keeyask, there could be similar involvement from the Department of Intergovernmental Affairs and International Relations so that it might provide advice regarding U.S. policy affecting export opportunities.

199 Information received from participant, March 24, 2020; Information received from participant, March 10, 2020.
200 Information received from participant, March 10, 2020.

STATUTORY MANDATE

Manitoba Hydro's statutory mandate is set out in section 2 of *The Manitoba Hydro Act*, as follows:

> **2** The purposes and objects of this Act are to provide for the continuance of a supply of power adequate for the needs of the province, and to engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power and, in addition, are
>
> (a) to provide and market products, services and expertise related to the development, generation, transmission, distribution, supply and end-use of power, within and outside the province; and
>
> (b) to market and supply power to persons outside the province on terms and conditions acceptable to the board.[201]

With respect to Bipole III, the Government gave direction to Manitoba Hydro to select a western route for reasons related to Manitoba's reputation in export markets, the Province's relations with Indigenous groups, and its bid for a UNESCO World Heritage Site designation.[202] With respect to Keeyask, the Government demonstrated through its NFAT Terms of Reference a priority for having Manitoba Hydro address northern and Indigenous economic and socio-economic development, adherence to the Province's Clean Energy Strategy, and the generation of the highest level of socio-economic benefits to Manitobans.[203]

These matters do not fall squarely within Manitoba Hydro's statutory mandate. Like any project developer, Manitoba Hydro should be expected to consider environmental effects[204] and impacts on Indigenous rights and interests[205] resulting from its proposed project. Manitoba Hydro should also be expected to comply with the Province's energy policy, as it is within the purview of the Government to set the policies to which Crown corporations (including Manitoba Hydro) must adhere. However, Crown corporations such as Manitoba Hydro are not well-suited to be an instrument for the Province to foster northern and Indigenous economic and socio-economic development, or socio-economic benefits to Manitobans more broadly. While it is hardly surprising that Manitoba Hydro followed the directions of its sole shareholder in these broader matters, expanding Manitoba Hydro's function beyond its statutory mandate erodes the purpose of creating Manitoba Hydro as a Crown corporation in the first place (as a specialized organization with expertise over the matters within its mandate).

Finding #2.14: The former Government's directions to Manitoba Hydro with respect to the routing of Bipole III and the NFAT Terms of Reference forced Manitoba Hydro to act beyond its statutory mandate "to engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power." In the case of Keeyask, it resulted in the pursuit of a project at least 10 years before it would be needed domestically.

201 *The Manitoba Hydro Act*, C.C.S.M. c. H190, s. 2.

202 Letter from Greg Selinger, then Minister Responsible for Manitoba Hydro, to Vic Schroeder, then Chair of the MHEB, September 20, 2007 [Appendix A, Tab 39].

203 NFAT Terms of Reference, p. 2 [Appendix A, Tab 69].

204 Environmental protection and the minimization of adverse environmental effects is an integral element of the licence approval process of projects under *The Environment Act*, C.C.S.M. c. E125.

205 Manitoba Hydro's function as a Crown corporation may also attract the Crown's duty to consult with Indigenous groups, as affirmed in *Haida Nation v. British Columbia (Minister of Forests)*, 2004 SCC 73.

Recommendation #2.11: Manitoba Hydro's statutory mandate should be amended to provide clarity in terms of its objectives and priorities. In the Commissioner's view, Manitoba Hydro's statutory mandate should not include socio-economic development. Rather, Manitoba Hydro's mandate should be to provide the most economic and efficient electric system within the boundaries of the Province's energy policy (which should not pre-determine projects or resource options). Manitoba Hydro should pursue and choose projects based on lowest cost and technical performance, not based on socio-economic development benefits. Issues of socio-economic development are broader matters of public policy and the responsibility of Government. It is the Government that is the custodian of the economy and pursues social policies in the collective interest.

If the Government decides that Manitoba Hydro should pursue and choose a project based on socio-economic development benefits, rather than lowest cost to ratepayers, the Government must be publicly transparent about that decision so that it can be held accountable, and taxpayers should be responsible for the incremental costs of that policy decision, not ratepayers.

CHAPTER 3

Net Benefits

> *[The NFAT Panel] noted that it was “unfortunate” that Manitoba Hydro was not able to provide the NFAT Panel with fully updated Expected NPV calculations, “as it left the NFAT Panel without one of the important decision making tools at its disposal.”*

INTRODUCTION

In accordance with section 3 of the Terms of Reference, the Commission inquired into the extent to which the estimated net benefits projected at the planning stages for Keeyask and Bipole III were:

(i) determined in accordance with best practices then applicable for such projects;

(ii) demonstrably superior to the estimated net benefits of proceeding with other options then available for addressing the Province’s then-anticipated electrical needs in a timely and cost-effective manner; and

(iii) based on sound export market forecasts.

This chapter presents the Commissioner’s findings and recommendations from this inquiry.

KEEYASK

Net Benefits Determined by Manitoba Hydro

Economic Benefits

In its NFAT submission, Manitoba Hydro estimated the net economic benefits of 15 different development plans, which are summarized in the chart below:[206]

Description of Manitoba Hydro's Development Plans

Plan	Short Name	Description
1	All Gas	Natural Gas-Fired Generation starting in 2022/23
2	K22/Gas	Keeyask 2022/23, Natural Gas-Fired Generation starting in 2029/30
3	Wind/Gas	Wind Generation starting in 2022/23 supported by Natural Gas-Fired Generation starting in 2025/26
4	K19/Gas24/250MW*	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2024/25, 250 MW Export/50 MW Import U.S. Interconnection 2020/21, 250 MW MP Sale
5	K19/Gas25/750MW(WPS Sale & Inv)**	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2025/26, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale, Proposed 300 MW WPS Sale
6	K19/Gas31/750MW	Keeyask 2019/20, Imports, Natural Gas-Fired Generation starting in 2031/32, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale
7	SCGT/C26	Simple Cycle Gas Turbine in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2038/39
8	CCGT/C26	Combined Cycle Gas Turbine in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2039/40
9	Wind/C26	Wind in 2022/23, Conawapa 2026/27, Natural Gas-Fired Generation starting in 2036/37
10	K22/C29	Keeyask 2022/23, Conawapa 2029/30, Natural Gas-Fired Generation starting in 2040/41
11	K19/C31/250MW*	Keeyask 2019/20, Natural Gas-Fired Generation starting in 2024/25, Conawapa 2031/32, 250 MW Export/50 MW Import U.S. Interconnection 2020/21, 250 MW MP Sale
12	K19/C31/750MW	Keeyask 2019/20, Imports, Conawapa 2031/32, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale
13	K19/C25/250MW*	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2040/41, 250 MW Export/50 MW Import U.S. Interconnection 2020/21, 250 MW MP Sale
14	K19/C25/750MW (WPS Sale & Inv) Preferred Development Plan**	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale, Proposed 300 MW WPS Sale
15	K19/C25/750MW	Keeyask 2019/20, Conawapa 2025/26, Natural Gas-Fired Generation starting in 2041/42, 750 MW Import/Export U.S. Interconnection 2020/21, 250 MW MP Sale

*Described as hypothetical due to Minnesota Power seeking regulatory approval for a 750 MW interconnection

**Adjusted to remove Wisconsin Public Service investment in the Great Northern Transmission Line

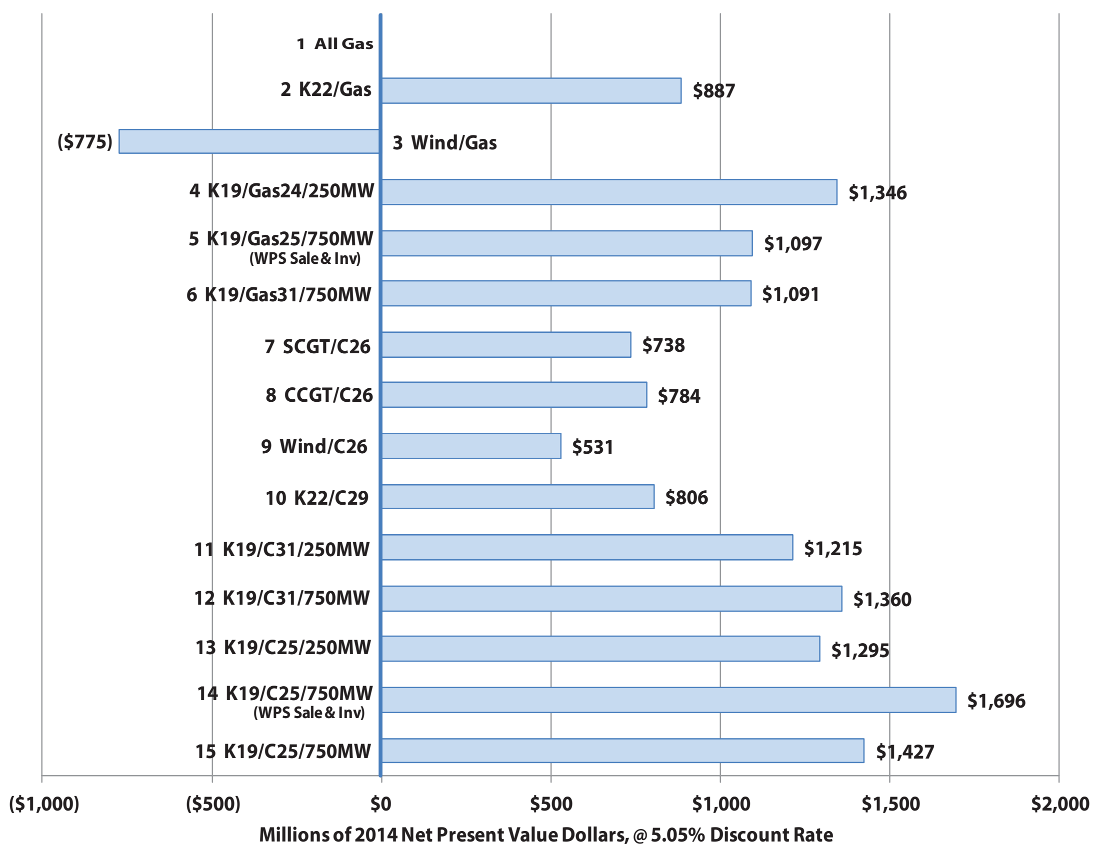
206 NFAT Report, p. 26 [Appendix A, Tab 15]. Manitoba Hydro described these development plans in its NFAT Submission, Chapter 8.

These plans were formulated after a screening process performed by Manitoba Hydro identified DSM, hydro, wind, natural gas, and imports as the portfolio of resource options that would be considered.[207] The development plans comprised what Manitoba Hydro considered "a sufficient number and size of resources to meet requirements or address opportunities over a 35-year planning horizon."[208]

Based on assumptions associated with its reference scenario,[209] Manitoba Hydro's NFAT submission compared the benefits and costs of the 15 plans it formulated, from its own perspective, using the NPV metric.[210] In the NFAT Report, the PUB defined this metric as follows:

> Net Present Value (NPV) is a standard economic analysis tool representing the present value of the future stream of annual revenues and costs. Because people tend to place a higher value on income today compared to income in the future, the stream of net benefits over time must be "discounted" at an appropriate rate to reflect this time preference. Net Present Value thus allows for alternatives with different costs and revenues that occur at different times to be compared on an equivalent basis at a single point in time.[211]

In the original NFAT submission in August 2013, Plan 14 (Manitoba Hydro's PDP) had the highest NPV for the reference scenario ("**Reference NPV**") of approximately $1.7 billion, as shown below:[212]



207 Manitoba Hydro, NFAT Submission, Chapter 7: Screening of Manitoba Resource Options, p. 12 [Appendix A, Tab 88].
208 Manitoba Hydro, NFAT Submission, Chapter 8: Determination and Description of Development Plans, p. 2 [Appendix A, Tab 89].
209 See **Appendix C** for the inputs and assumptions comprising Manitoba Hydro's reference scenario for the economic evaluation of its development plans, as excerpted from Manitoba Hydro NFAT Submission, Chapter 9.
210 The process through which Manitoba Hydro calculated NPVs for the reference scenario is set out in its NFAT Submission, Chapter 9: Economic Evaluations – Reference Scenario [Appendix A, Tab 90].
211 NFAT Report, p. 136 [Appendix A, Tab 15], citing Manitoba Hydro, NFAT Submission, Chapter 9: Economic Evaluations – Reference Scenario, p. 3 [Appendix A, Tab 90].
212 Manitoba Hydro, NFAT Submission, Chapter 9: Economic Evaluations – Reference Scenario, p. 15, Figure 9.2 [Appendix A, Tab 90]; NFAT Report, p. 139, Figure 11 [Appendix A, Tab 15].

In March 2014, Manitoba Hydro provided the NFAT Panel with updates reflecting the following four key changes in its underlying development plan assumptions:

- the capital cost estimates for Keeyask and Conawapa had increased by approximately $300 million and $500 million, respectively;
- new DSM scenarios comprising DSM Levels 1-3, of which DSM Level 2 would be pursued;
- WPS would not be investing in the 750 MW transmission interconnection included in some plans (such as the PDP); and
- the prospect of increased load from new pipelines.[213]

With the new March 2014 information revising Manitoba Hydro's cost and forecast assumptions, the PDP's Reference NPV was reduced from $1.7 billion to $45 million, which was one of the lowest Reference NPVs among the development plans being considered. The updated Reference NPVs are shown below:[214]

	Incremental Net Present Value, (Millions of $(2014)) Relative to All Gas at Specified Level of DSM			
	Base DSM	DSM Level 1	DSM Level 2	DSM Level 3
Plan 2 (K23/Gas)	164 Gas 2029		-38 K 2031	
Plan 2 Modified (K19/Gas)			1 Gas 40	
Plan 4 – Hypothetical (K19/Gas/250MW)			604 Gas 2040	
Plan 5 (K19/Gas/750MW)	377 Gas 2026	339 Gas 2030	410 Gas 2031	373 Gas 2033
Plan 5 (K19/Gas/750MW) – With Pipeline			339 Gas 2030	361 Gas 2030
Plan 5 Keeyask Deferral Scenario 1 (K26/Gas/750MW19) – With Pipeline			259 Gas 2030	
Plan 5 Keeyask Deferral Scenario 2 (K26/Gas/750MW19) – With Pipeline			345 Gas 2030	
Plan 6 (K19/Gas/750MW)			386 Gas 2040	
Plan 12 (K19/C40/750MW)			-18 Conawapa 2040	
Plan 14 (K19/C/750MW) – With Pipeline	374 Conawapa 2026	124 Conawapa 2030	45 Conawapa 2031	-7 Conawapa 2033

Based on the updated March 2014 information, of the development plans that Manitoba Hydro considered feasible, Plan 6 (Keeyask in 2019, gas in 2040, and the 750 MW interconnection) had the highest updated Reference NPV of $386 million relative to the All-Gas Plan.[215] However, it was

213 NFAT Report, p. 140 [Appendix A, Tab 15].
214 NFAT Report, p. 143, Table 13 [Appendix A, Tab 15].
215 Plan 4 had a higher updated Reference NPV, but it was no longer considered feasible because it included a 250 MW transmission line, whereas MP had applied to construct to a 750 MW line: NFAT, Exhibit MH-104-3-2, p. 1 [Appendix A, Tab 91]; NFAT Report, pp. 24, 26, 150 [Appendix A, Tab 15]. Plan 5 included the WPS 308 MW contract, which had a termination clause that allowed WPS to cancel it if Conawapa was not built: 308 MW System Power Agreement between MHEB and WPS, February 26, 2014, pp. 114-120, 123; NFAT Report, p. 111 [Appendix A, Tab 15].

known during the NFAT that the "high" range of capital costs for Keeyask ($7.2 billion) could reduce this NPV by over $1 billion, which would make it (and other plans with Keeyask) less economical than the All-Gas Plan.[216] The NFAT Panel did not consider this "high" range unlikely. Based on the cost reimbursable nature of the GCC, the NFAT Panel stated that the "cost of Keeyask will increase beyond Manitoba Hydro's currently projected capital cost of $6.5 billion" and that "[b]udgeting at least for Manitoba Hydro's 'high' estimate of $7.2 billion would be prudent."[217]

In addition to Reference NPVs, Manitoba Hydro also determined Expected NPVs of 12 of its 15 development plans, as part of its economic uncertainty analysis. This analysis examined a range of uncertainties around three key factors: energy prices, discount rates used to calculate NPVs, and capital costs.[218] A low, reference, and high range was developed for each of the three factors with probability weightings for each determined by Manitoba Hydro, resulting in 27 scenarios with varying NPVs and probabilities.[219]

Using these 27 scenarios, Manitoba Hydro determined **Expected NPVs**, which reflected the probability-weighted average of all scenarios for each plan. The Expected NPVs were the sum of each scenario's NPV multiplied by the probability of its occurrence.[220]

In the original NFAT submission in August 2013, the PDP had the highest Expected NPV of $1.085 billion, as shown below:[221]

Development Plan	1	3	7	2	4	13	11	6	15	12	5	14
	All Gas	Wind/Gas	SCGT/C26	K22/Gas	K19/Gas24 /250Mw	K19/C25 /250MW	K19/C31 /250MW	K19/Gas31 /750MW	K19/C25 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
											WPS Sale & Investment	
	Millions of 2014 NPV dollars											
10th Percentile -"Risk"	-3502	-4599	-1217	-1249	-898	-1988	-1362	-1181	-2186	-1594	-828	-1429
25th Percentile	-560	-2200	-297	-248	115	-650	-363	-183	-904	-361	139	-204
75th Percentile	1481	383	1363	1636	2092	1854	2074	1832	2008	2009	1726	2255
90th Percentile - "Reward"	1905	1209	1956	2007	2479	3180	2953	2215	3360	3220	2256	3377
Expected Value	-70	-1084	455	564	971	712	736	706	760	821	772	1085
Ref-Ref-Ref NPV	0	-775	738	887	1346	1295	1215	1091	1427	1360	1097	1696

In March 2014, Manitoba Hydro updated the Expected NPV calculations for 8 of its 15 plans. This update incorporated the increased capital cost estimates for Keeyask and Conawapa and loss of WPS investment in the 750 MW interconnection, but it did not incorporate enhanced DSM or increased pipeline load. Similar to the Reference NPV update, the updated Expected NPV calculations showed that the PDP had one of the lowest Expected NPVs among the plans for which updated calculations were provided. The updated Expected NPVs are shown below:[222]

Development Plan	1	2	4	8	6	12	5	14
	All Gas	K22/Gas	K19/Gas24 /250MW	CCGT/C26	K19/Gas31 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
							WPS Sale & no WPS Inv	
	Millions of 2014 NPV Dollars							
10th Percentile -"Risk"	-953	-862	-727	-1457	-1007	-2512	-909	-2946
25th Percentile	-244	-622	-290	-980	-556	-1482	-367	-1760
75th Percentile	483	1026	1339	916	1099	1232	824	1105
90th Percentile - "Reward"	738	1448	2019	1898	1749	3239	1475	3653
Expected Value	-9	268	651	143	386	115	268	120
Ref-Ref-Ref NPV	0	489	917	403	662	536	484	614

216 NFAT, Exhibit MH-104-8, p. 3 [Appendix A, Tab 91].
217 NFAT Report, p. 132 (emphases added) [Appendix A, Tab 15].
218 Manitoba Hydro, NFAT Submission, Chapter 10: Economic Uncertainty Analysis, pp. 2-4 [Appendix A, Tab 92]; NFAT Report, p. 146 [Appendix A, Tab 15].
219 Manitoba Hydro, NFAT Submission, Chapter 10: Economic Uncertainty Analysis, p. 2 [Appendix A, Tab 92]; NFAT Report, p. 147 [Appendix A, Tab 15].
220 Manitoba Hydro, NFAT Submission, Chapter 10: Economic Uncertainty Analysis, p. 16 [Appendix A, Tab 92]; NFAT Report, pp. 146-147 [Appendix A, Tab 15].
221 Manitoba Hydro, NFAT Submission, Chapter 10: Economic Uncertainty Analysis, p. 17, Table 10.6 [Appendix A, Tab 92]; NFAT Report, p. 148, Table 16 [Appendix A, Tab 15].
222 NFAT, Exhibit MH-104-8, p. 3 [Appendix A, Tab 91]; NFAT Report, pp. 149-150, Table 17 [Appendix A, Tab 15].

The NFAT Panel received comments from several witnesses about the limitations of Manitoba Hydro's updated uncertainty analysis, particularly the fact that the updated Expected NPVs did not reflect new levels of DSM which many felt hampered Manitoba Hydro's analysis.[223] The NFAT Panel agreed that Expected NPVs are one of the most important risk analysis outputs in comparing the economics of plans. It noted that it was "unfortunate" that Manitoba Hydro was not able to provide the NFAT Panel with fully updated Expected NPV calculations, "as it left the NFAT Panel without one of the important decision making tools at its disposal."[224] As a result, the NFAT Panel was not in a position to comment on how the PDP would have performed relative to other plans on a risk-adjusted basis.[225]

By the time Manitoba Hydro provided updated information in March 2014, there was little more than three months until the NFAT Report was due. The NFAT Terms of Reference stated that the NFAT Panel was to provide its report by June 20, 2014,[226] which required time for the NFAT Report to be written after the close of the evidentiary record. Neither the NFAT Terms of Reference nor the order in council establishing the NFAT[227] permitted the PUB to request more time to provide its report for any reason, including if more evidence was necessary.

Finding #3.1: Manitoba Hydro's economic analysis did not fully account for changes in underlying assumptions by the time the NFAT ended. This limited the NFAT Panel's ability to compare plans (particularly on a risk-adjusted basis) and to make an informed decision. Further, Manitoba Hydro's limited analysis showed that as of March 2014 the PDP was not the optimal development plan from an NPV perspective (neither Reference NPV nor Expected NPV). While the NFAT Panel concluded that plans with Keeyask and a transmission intertie outperformed the All-Gas Plan, it also indicated that the "high" range of capital costs for Keeyask ($7.2 billion) – which would make plans with it less economical than the All-Gas Plan – was likely. These findings should have caused the PUB, Government, the MHEB, and Manitoba Hydro to seriously reconsider whether Keeyask should have been pursued at that time. However, the Commission was not provided with any evidence to suggest that such reconsiderations occurred.

Recommendation #3.1: Manitoba Hydro's assessment of project alternatives must be flexible enough to account for changes in underlying assumptions up to the point in time when a final approval/sanctioning decision is made. Often, a project gains momentum as it proceeds through the planning phases. However, before significant long-term capital is invested in a project, it is critical for the ultimate decision makers to make a fresh, objective assessment of the need for the project and whether it should proceed instead of other possible alternatives. The PUB's review process should similarly ensure that projects are not recommended to proceed unless they are the best solution for the Province, based on the best available information at that time.

Finding #3.2: The NFAT Panel faced time constraints given that the NFAT Report was to be provided by June 20, 2014. These time constraints appear to have led the NFAT Panel to proceed based on the partially updated March 2014 information and without fully updated analysis, including fully updated Expected NPVs which the NFAT Report described as "one of the important decision-making tools at its disposal."

Recommendation #3.2: The Government should ensure that the timelines provided for public reviews of major new facilities are reasonable in light of the scope of such reviews and their terms of reference. The PUB must have the ability to request an extension if more time is necessary to complete a review of a major new facility, including if more evidence is needed to fulfill its mandate.

223 NFAT Report, p. 153 [Appendix A, Tab 15].
224 NFAT Report, p. 161 [Appendix A, Tab 15].
225 NFAT Report, p. 151 [Appendix A, Tab 15].
226 NFAT Terms of Reference, p. 2 [Appendix A, Tab 69].
227 Order in Council 128/2013 [Appendix A, Tab 93].

Recommendation #3.3: Members of the PUB should be appointed for long terms with limited ability for the Government to terminate them during their terms, in order to ensure that members are less sensitive to politics in making their decisions. Currently, *The Public Utilities Board Act* provides that each member of the PUB holds office during pleasure of Cabinet (i.e., Cabinet can terminate them at pleasure). Some provinces have legislated minimum terms for members of utility commissions and boards. The Government of Manitoba should consider amending *The Public Utilities Board Act* to include such minimum terms for members of the PUB.

Socio-economic Benefits

In its NFAT submission, Manitoba Hydro estimated the net socio-economic benefits for various future resource options in a limited scope assessment, largely restricted to four considerations:

1. A qualitative assessment of the socio-economic benefits of a limited set of different resource technology options (DSM, hydro, wind, and natural gas), from which Manitoba Hydro prepared the following overview of a specific set of socio-economic considerations:[228]

	DSM	Keeyask	Conawapa	Wind	Heavy Duty CCGT	Heavy Duty SCGT
Health Concerns	-	Very Low	Very Low	Low	Low	Low
Safety Concerns	-	Medium	Medium	Very Low	High	High
MBBusinessOpportunities (% of capital spent in MB)	100%	53%	46%	18%	30%	17%
Employment Direct Construction	Program Dependent	4480 Person-Years	6650 Person-Years	35 to 80 Person-Years	329 Person-Years	116 Person-Years
At Northern Work Sites	Program Dependent	94%	94%	0%	0%	0%
Permanent O&M	Minimal	58 FTE	61 FTE	4 to 8 FTE	94 FTE (for 1 to 2 plants at site)	52 FTE (for 1 to 4 plants at site)
At Northern Work Sites	0%	100%	100%	0%	0%	0%
Royalties / Taxes (2014$) Water Rentals	-	$9.0 M/year	$12.8 M/year	-	-	-
Capital Taxes	Program Dependent	$17.3 M/year	$28.6 M/year	$0.8 M/year	$2.0 M/year	$0.8 M/year
Guarantee Fees	Program Dependent	$27.7 M/year	$45.8 M/year	Potential for $1.3 M/year	$3.2 M/year	$1.3 M/year

2. An economic impact analysis of the PDP (including Keeyask), from which Manitoba Hydro estimated economic impacts of each component for Manitoba and the rest of Canada in the table below:[229]

Manitoba - Economic Impacts of the Preferred Development Plan[1,2]

	Keeyask		Conawapa		North-South Upgrades	750 MW Interconnection	
	Construction	O&M[3]	Construction	O&M[3]	Construction	Construction	O&M[3]
Employment (person years)							
Project Direct	2,436	39	3,238	42	171	119	1
Other Direct	2,175	2	1,831	2	164	124	0
Indirect and Induced	3,736	29	4,234	33	251	255	1
Total Employment (person-years)	8,347	70	9,303	77	586	498	2
Labour Income	$ 635,169	$ 5,921	$ 761,233	$ 6,597	$ 48,627	$ 35,195	$ 123
GDP ($millions)	$ 843,908	$ 6,872	$ 983,334	$ 7,676	$ 67,189	$ 50,209	$ 149
Tax Revenues ($millions)							
Provincial	204,340	831	$ 256,096	$ 931	$ 13,954	$ 16,069	22
Local	40,915	162	$ 45,807	$ 182	$ 2,186	$ 2,478	$ 5
Federal	161,059	988	195,872	1,099	12,538	10,714	23
Total Tax Revenue ($ millions)	$ 406,314	$ 1,981	$ 497,776	$ 2,212	$ 28,679	$ 29,261	$ 51

228 Manitoba Hydro, NFAT Submission, Chapter 7: Screening of Manitoba Resource Options, p. 39 [Appendix A, Tab 88]; NFAT Report, p. 211 [Appendix A, Tab 15].

229 Manitoba Hydro, NFAT Submission, Appendix 2.3: Economic Impact Assessment, p. 4 [Appendix A, Tab 94]; NFAT Report, p. 214 [Appendix A, Tab 15].

Rest of Canada - Economic Impacts of the Preferred Development Plan[1]

	Keeyask		Conawapa		North-South Upgrades	750 MW Interconnection	
	Construction	O&M[3]	Construction	O&M[3]	Construction	Construction	O&M[3]
Employment (person years)							
Project Direct	2,532	-	3,915	-	-	0	-
Other Direct	3,198	1	3,448	1	219	144	0
Indirect and Induced	10,414	16	13,601	18	386	444	1
Total Employment (person-years)	16,144	17	20,964	19	605	588	1
Labour Income	$ 1,021,350	$ 648	$ 1,402,932	$ 734	$ 30,606	$ 24,977	$ 23
GDP ($millions)	$ 1,440,223	$ 1,054	$ 1,997,461	$ 1,184	$ 54,676	$ 39,642	$ 37
Tax Revenues ($ millions)							
Provincial	$ 251,927	$ 117	$ 342,663	$ 132	$ 7,546	$ 7,146	$ 5
Local	$ 66,289	$ 31	$ 90,164	$ 35	$ 1,986	$ 1,880	$ 1
Federal	$ 307,444	$ 128	$ 426,252	$ 144	$ 10,935	$ 12,437	$ 5
Total Tax Revenue ($ millions)	$ 625,660	$ 276	$ 859,080	$ 311	$ 20,467	$ 21,463	$ 12

All of Canada - Economic Impacts of the Preferred Development Plan[1]

	Keeyask		Conawapa		North-South Upgrades	750 MW Interconnection	
	Construction	O&M[3]	Construction	O&M[3]	Construction	Construction	O&M[3]
Employment (person years)							
Project Direct	4,967	39	7,154	42	171	119	1
Other Direct	5,374	3	5,279	4	383	268	0
Indirect and Induced	14,151	45	17,834	50	637	700	1
Total Employment (person-years)	24,491	87	30,267	96	1,191	1,086	2
Labour Income	$ 1,656,519	$ 6,569	$ 2,164,166	$ 7,331	$ 79,233	$ 60,173	$ 145
GDP ($millions)	$ 2,284,131	$ 7,926	$ 2,980,795	$ 8,860	$ 121,865	$ 89,851	$ 186
Tax Revenues ($ millions)							
Provincial	$ 456,268	$ 948	$ 598,759	$ 1,063	$ 21,501	$ 23,215	$ 27
Local	$ 107,204	$ 193	$ 135,972	$ 217	$ 4,172	$ 4,358	$ 7
Federal	$ 468,502	$ 1,116	$ 622,124	$ 1,243	$ 23,474	$ 23,150	$ 29
Total Tax Revenue ($ millions)	$ 1,031,974	$ 2,257	$ 1,356,855	$ 2,523	$ 49,146	$ 50,724	$ 62

[1] 2014 dollars

[2] Total may not add, due to rounding

3. A more detailed analysis of expected socio-economic benefits of Keeyask, from which Manitoba Hydro identified the following employment benefits for Indigenous people in northern Manitoba: [230]

Direct Employment	Keeyask Cree Nations	Northern Aboriginal Residents
Construction	Infrastructure: up to 110 person years; Generation: 235 to 600 person years Other: 35-40 person years	Infrastructure: up to 138 person years, including KCNs Generation: 550-1700 person years (315-1100 persons excluding KCNs)
Operations	45% of 50 estimated positions to be aboriginal Minimum 182 positions	45% of 50 estimated positions to be aboriginal

230 NFAT Report, p. 220 [Appendix A, Tab 15]; NFAT, Exhibit MH-159, pp. 1-3 [Appendix A, Tab 95].

Manitoba Hydro also estimated annual economic benefits to the Keeyask Cree Nations ("**KCN**") if they were to invest in Keeyask through the preferred equity option,[231] as follows:[232]

Period	Total/Per Capita	Annual Estimated Range of Benefits	
		Low Estimate	High Estimate
Construction	Total ($ million)	$10.26	$20.67
	Per capita ($)	$1,616	$3,255
Post Construction @ 1.9% equity ownership/6 years post construction	Total Benefits ($ million)	$9.58	$19.92
	Per capita ($)	$1,509	$3,137
Post Construction @ 2.5% equity ownership/6 years post construction	Total Benefits ($ million)	$9.58	$21.36
	Per capita ($)	$1,509	$3,363

231 Under the JKDA, the four KCNs that are parties to the agreement have two options to invest in the project: a common equity option, which allows the community to obtain a proportionate share of cash distributions from the project based on financial performance, and a preferred equity option, which involves a guaranteed return of approximately $5 million per year: NFAT Report, p. 219 [Appendix A, Tab 15].

232 NFAT Report, p. 221 [Appendix A, Tab 15]; NFAT, Exhibit CAC-85-1, p. 2 [Appendix A, Tab 96].

4. A Multiple Account Benefit Cost Analysis ("**MA-BCA**") to determine net benefits of four of Manitoba Hydro's 15 development plans (including the PDP) that would accrue to various stakeholders (accounts), including Manitoba Hydro, ratepayers, Government, and the Manitoba economy in general: [233]

<table>
<tr><th></th><th>Preferred Development Plan</th><th>K19/G24/250MW</th><th>K22/Gas</th><th>All Gas</th></tr>
<tr><td><u>Market Valuation</u>
Net revenues (cost) to MH and partners</td><td>--</td><td>17.0</td><td>(270.5)</td><td>(654.1)</td></tr>
<tr><td><u>Customer Account</u>
Cumulative rate increase</td><td colspan="4">Preferred Development Plan has highest rate increases in first 20 years (cumulatively 16 to 18 percentage points more than the alternative plans) but has lowest rate increases over long term (cumulatively by year 50 approximately 34 to 37 percentage points less than the two alternatives with Keeyask G.S. and 70 percentage points less than the all gas plan).</td></tr>
<tr><td>Reliability</td><td colspan="4">Preferred Development Plan and to lesser extent the alternative with the smaller interconnection provides greater load carrying capability, lower expected loss of unserved energy and greater ability to manage extreme drought</td></tr>
<tr><td><u>Government</u>
Incremental revenues net of costs/risk</td><td>--</td><td>(353.5)</td><td>(395.9)</td><td>(674.2)</td></tr>
<tr><td><u>Manitoba Economy</u>
Employment net benefits</td><td>--</td><td>(100.7)</td><td>(120.1)</td><td>(192.7)</td></tr>
<tr><td><u>Environment</u>
Manitoba GHG external cost</td><td>--</td><td>(208.6)</td><td>(174.3)</td><td>(320.3)</td></tr>
<tr><td>Global GHG impact</td><td colspan="4">Preferred Development Plan and to lesser extent the two plans with Keeyask G.S. would contribute to a reduction in global emissions by displacing thermal generation in US.</td></tr>
<tr><td>Manitoba CAC damage cost</td><td>--</td><td>(8.6)</td><td>(7.1)</td><td>(13.3)</td></tr>
<tr><td>Residual biophysical</td><td colspan="4">Aquatic and terrestrial impacts with hydro projects in Preferred Development Plan and plans with Keeyask G.S.; subject to detailed environmental hearings, residual effects and local external cost expected to be relatively small with initial design, extensive mitigation, monitoring, compensation and benefit-sharing arrangements.</td></tr>
<tr><td><u>Social</u>
Partner net return</td><td colspan="4">Significant net returns from up to 25% interest in Keeyask G.S. and income benefits from Conawapa G.S. in Preferred Development Plan; significant benefits from up to 25% interest in two alternatives with Keeyask G.S., greater with new sales and interconnection.</td></tr>
<tr><td>Community impacts</td><td colspan="4">Wide range of potential impacts on local employment and business; population, infrastructure and service; social and community well-being; owners of land needed for rights of way and easements; major commitments and plans to minimize adverse residual effects with extensive mitigation, monitoring, compensation and partnership arrangements.</td></tr>
<tr><td>Other Manitoba</td><td colspan="4">Potentially significant bequest value from the hydro assets remaining at end of planning period; greatest with Preferred Development Plan and to a lesser extent in the alternatives with Keeyask G.S.</td></tr>
<tr><td>Overall Monetized Net Benefit (Cost)</td><td>--</td><td>(654.4)</td><td>(967.5)</td><td>(1,854.6)</td></tr>
</table>

NFAT REFERENCE SCENARIO ASSUMPTIONS (2014 PRESENT VALUE IN MILLIONS OF 2014$)

233 Manitoba Hydro NFAT Submission, Chapter 13: Integrated Comparisons of Development Plans, p. 67 [Appendix A, Tab 97]; NFAT Report, p. 224 [Appendix A, Tab 15]. See **Appendix D** for tables summarizing accounts of Manitoba Hydro's MA-BCA, as excerpted from Manitoba Hydro NFAT Submission, Chapter 13.

Finding #3.3: A socio-economic analysis was required pursuant to the NFAT Terms of Reference, even though socio-economic benefits are beyond Manitoba Hydro's statutory mandate, which is focused on "economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power," as discussed in Chapter 2.

Particularly in combination with the exclusion of Bipole III from the NFAT Terms of Reference (which, as discussed elsewhere in this chapter, biased the analysis in favour of Keeyask), the Commissioner concludes that the addition of a socio-economic analysis favoured Keeyask and the PDP by giving additional justification for proceeding with hydroelectric generation options even if those options were riskier and more expensive than other resource options.

Recommendation #3.4: Unless Manitoba Hydro is directed by the Government to pursue and choose a project based on socio-economic benefits, such benefits should not be considered in the assessment of a development plan or project unless more than one development plan or project are equal in terms of cost and technical performance. The primary assessment of a development plan or project in terms of cost and technical performance is consistent with Manitoba Hydro's current (and recommended) mandate to "engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power."

If Manitoba Hydro is directed by the Government to pursue and choose a project based on socio-economic benefits, rather than lowest cost to ratepayers, the socio-economic benefits of a development plan or project should be evaluated against its incremental costs relative to the lowest-cost option (which, as stated in Recommendation #2.11, should be borne by taxpayers, not ratepayers).

Consistency with Best Practices

Economic Benefits

Length of Study Period

In its NPV analysis of the economic benefits of its 15 development plans, Manitoba Hydro used a 78-year study period. This 78-year period comprised a 35-year detailed analysis of each plan and a 43-year extrapolation of the values used in that detailed analysis.[234] The basis for using a 78-year study period was to include the full service life of the longest-lived asset, the hydroelectric generating stations (Keeyask and Conawapa).

During the NFAT, some experts cautioned that a 78-year study period involved much uncertainty[235] and is unusual, and that long-term forecasts for plans with high front-end costs are commonly given much less weight.[236] Based on the updated March 2014 information, LCA estimated that several

234 NFAT Report, pp. 137, 157 [Appendix A, Tab 15]; Manitoba Hydro, NFAT Submission, Chapter 9: Economic Evaluations – Reference Scenario, pp. 7-8 [Appendix A, Tab 90].

235 NFAT, Exhibit MMF-31, pp. 5-6 [Appendix A, Tab 98]; NFAT, Transcript, p. 10591 [Appendix A, Tab 99]; NFAT, Exhibit MPA-3, p. 16 [Appendix A, Tab 100].

236 LCA noted that it is typical in the industry to conduct planning over 20 to 30 years: NFAT, Exhibit LCA-12, p. 9A-24 [Appendix A, Tab 101].

development plans would not break even (i.e., have their CPV – their NPV at a given time – equal to that of the All-Gas Plan) for several decades, as shown below:[237]

Plans	78 Year CPV of Total Capital	78 NPV	50 CPV	35 CPV	20 CPV	78 Year IRR	Break Even Year (All Gas) Base Case
1 All Gas	$2,764	$0	$0	$0	$0	N/A	N/A
2 K31/Gas29	$4,429	($38)	($349)	($798)	($1,781)	5.28%	N/A
4 K19/Gas40/250MW	$5,774	$604	$239	($284)	($1,541)	6.26%	2055
5 K19/Gas31/750MW (WPS	$6,215	$410	$10	($523)	($1,899)	5.92%	2062
6 K19/Gas40/750MW	$6,175	$386	($5)	($555)	($1,876)	5.90%	2063
12 K19/C40/750MW	$8,421	($18)	($954)	($2,261)	($2,395)	5.36%	N/A
14 K19/C31/750 (WPS)	$9,528	$45	($863)	($2,173)	($5,298)	5.42%	2089

As the table shows, the break-even year for development plans with Keeyask was at least 40 years into the future (it was in 2063 for Plan 6 and in 2089 for the PDP). In other words, all the development plans with Keeyask were highly exposed to the uncertainty of long-term assumptions.

The above table also shows the CPV (i.e., NPV at a given time) of those development plans after 20, 35, 50, and 78 years (which LCA calculated, not Manitoba Hydro), as well as their IRR. The IRR is the interest rate at which the NPV of a development plan's costs equals the NPV of its benefits and represents the average annual return relative to the All-Gas Plan.[238] As the above table shows, the PDP had one of the lower IRRs of the development plans under consideration.

The NFAT Panel concluded that while NPV is an appropriate metric and useful guide to decision making, IRR and CPV complemented it and the NFAT Panel noted that it considered them in assessing the economics of the development plans.[239] This conclusion appears to be in agreement with LCA, which stated that the NPV metric was important, but that it was also valuable to consider other metrics like IRR "that better articulate the temporal relationship between investments and the associated benefits expected from those investments."[240] The IRR and CPV metrics in the NFAT demonstrated the long-term risks associated with Keeyask relative to other supply options.

The Commission heard during an interview with a former executive of Manitoba Hydro that nobody knows with any certainty what domestic load will be 10 or more years in the future.[241] It is also worth noting that:

- in recent years (including before the NFAT) Manitoba Hydro consistently overestimated domestic demand growth and the PUB has repeatedly criticized Manitoba Hydro's forecasts during GRAs,[242] as discussed in Chapter 1; and
- while the NFAT Panel was satisfied that Manitoba Hydro's load forecast was reasonable in the short term, it had less confidence in its load forecast over the long term given its inability to anticipate fundamental structural change (e.g., grid parity), as discussed in Chapter 1.

These points are significant given the long-term load forecasts on which the economics of development plans with Keeyask depended.

237 NFAT, Exhibit, LCA-3-3, p. 9S-8, Figure 9-21S [Appendix A, Tab 102].
238 NFAT Report, p. 136 [Appendix A, Tab 15].
239 NFAT Report, p. 159 [Appendix A, Tab 15].
240 NFAT Report, p. 158 [Appendix A, Tab 15], citing NFAT, Exhibit LCA-12, p. 9A-24 [Appendix A, Tab 101].
241 Information received from participant, March 11, 2020.
242 PUB Order No. 73/15, p. 78 [Appendix A, Tab 53]; PUB Order No. 99/11, pp. 52, 92-93 [Appendix A, Tab 14]; PUB Order No. 43/13, pp. 36-37 [Appendix A, Tab 61]. NFAT Report, pp. 71-72 [Appendix A, Tab 15].

Finding #3.4: While use of NPV as a metric for economic analysis is generally a best practice, Manitoba Hydro's NPV analysis used a very long study period of 78 years (including a 43-year extrapolation), which is not normal practice in the industry according to La Capra Associates Inc. and the Commission's review of recent long-term electricity projects and major transmission lines in Canada (see **Appendix E**). Its NPV analysis was heavily reliant on long-term assumptions, which was not reasonable given their inherent uncertainty and the inability to anticipate potential fundamental structure change. The COVID-19 pandemic demonstrates that even short-term assumptions can be unreliable, let alone 78-year assumptions.

Recommendation #3.5: In addition to Recommendation #1.9, the Commissioner recommends that CPV be used as a metric for economic analysis along with NPV, in order to capture important information regarding the timing of costs and benefits of a project or development plan through the study period (and not just at the end of the study period, like NPV). CPV allows for economic analysis within more certain time frames and discloses intergenerational costs and benefits. Given the increasing unreliability of assumptions over time, this information captured by CPV should be considered in any economic analysis.

Treatment of Sunk Costs

In Manitoba Hydro's NPV analysis, prior expenditures on Keeyask ($1.2 billion) and Conawapa ($400 million) were treated as common costs to all plans, rather than as costs applied only to the plans that included these generating stations. Some witnesses during the NFAT process suggested that this treatment biased Manitoba Hydro's analysis in favour of Keeyask and Conawapa.[243]

Costs of Bipole III were also treated as a common cost and were treated as a neutral factor in assessing all resource plans.[244] At least one witness during the NFAT was of the view that the costs of Bipole III should not have been treated in this way because only the hydro-based plans required Bipole III's construction. In that witness' opinion, applying the cost of Bipole III to the whole system (rather than the hydro-based plans that required it) further biased Manitoba Hydro's analysis in favour of Keeyask.[245]

Finding #3.5: The "sunk costs" of Keeyask (including the KIP) and Conawapa impacted the analysis of net economic benefits and favoured the hydro-based plans. If $1.2 billion and $400 million had not been spent on Keeyask and Conawapa, respectively, the relative economic benefits for development plans that did not include Keeyask and Conawapa would have been much higher. If those costs had not already been spent, they would have only been attributed to development plans with Keeyask and/or Conawapa, rather than to all development plans (including those with neither Keeyask nor Conawapa).

Finding #3.6: By incurring substantial costs on Keeyask and Conawapa and then treating them as "sunk costs" common to all plans along with the costs of Bipole III, Manitoba Hydro did not assess alternatives based on a "like to like" comparison (i.e., a comparison using consistent inputs). In a "like to like" comparison, each of the plans would only include the costs properly attributable to their components, so that they could be compared on a similar, consistent basis. Keeyask and Conawapa were not components of every plan, and neither was included in the All-Gas Plan. In a "like to like" comparison, their "sunk costs" would have been added to the hydro-based plans that included them and only to those plans. Such a comparison is important because without consistent inputs, no logical and reliable conclusions about relative net benefits can be drawn.

243 NFAT Report, p. 158 [Appendix A, Tab 15].
244 NFAT Report, p. 27 [Appendix A, Tab 15].
245 NFAT, Exhibit MMF-31, pp. 23-24 [Appendix A, Tab 98].

The way in which "sunk costs" of Keeyask and Conawapa were treated also assumed that those costs would be a total write off, which may not have been the case. Limestone was delayed for years following preliminary construction before it was later completed (as discussed in Chapter 5). Costs spent on its preliminary construction were not lost, just as costs spent on Keeyask and Conawapa may not have been.

Recommendation #3.6: In identifying the preferred option to meet Manitoba's energy needs, alternatives should be assessed based on a "like to like" comparison of their individual merits. Only costs associated with the specific development plan being considered, as well as associated facilities required for that development plan, should be assessed as the costs for that development plan.

Treatment of Export Contracts

Before the NFAT, Manitoba Hydro signed long-term export sales contracts with MP, among other parties, which it factored into its NPV assessment of hydro-based plans. In particular, a 250 MW export contract was signed with MP in 2011, for which the construction of Keeyask was a condition precedent. While Manitoba Hydro could have chosen to waive that condition precedent, it had always represented to MP that the 250 MW contract would be served by Keeyask.[246]

The NFAT Panel concluded that cancelling Keeyask would have resulted in material consequences for ratepayers, because Manitoba Hydro's commercial reputation could suffer, among other reasons. It concluded that even delaying Keeyask could have presented commercial consequences and affected export contracts, leading to future negotiation consequences.[247]

Finding #3.7: Export contracts such as the 250 MW contract with MP influenced the NFAT Panel's conclusions and recommendations. The NFAT Panel concluded against recommending even a delay of Keeyask based on the affected export contracts (e.g., the 250 MW sale to MP) and potential commercial and future negotiation consequences.

Recommendation #3.7: While it is reasonable for Manitoba Hydro to negotiate long-term power sales agreements, the contracts should not pre-determine the preferred energy supply option before that option has been approved and sanctioned. Similarly, the fact that a contract has been executed should not be the justification for proceeding with one resource option over another, otherwise preferable, option. To the extent that Manitoba Hydro enters into a power sales agreement that is contingent on a particular project proceeding that has not yet been sanctioned, Manitoba Hydro should ensure that it has the right to terminate the contract without any material penalty if that project is ultimately not sanctioned.

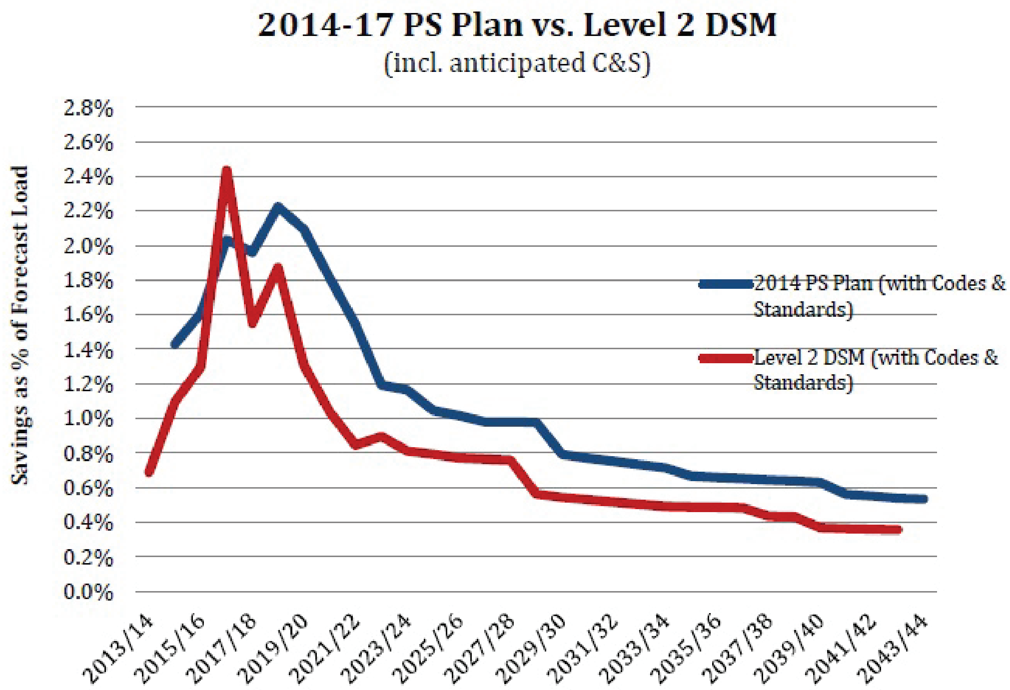
Treatment of DSM

Manitoba Hydro did not treat DSM as a stand-alone resource option competitive with other generation options in its resource planning and analyses for the NFAT. The NFAT Panel concluded that this was contrary to best practices and that Manitoba Hydro's DSM analysis "was neither complete, accurate, thorough, reasonable, nor sound."[248]

While the NFAT Panel accepted Manitoba Hydro's updated NPV analysis incorporating DSM Level 2, numerous witnesses suggested Manitoba Hydro could have achieved greater DSM savings and that

246 NFAT Report, p. 110 [Appendix A, Tab 15].
247 NFAT Report, p. 247 [Appendix A, Tab 15].
248 NFAT Report, pp. 91-92 [Appendix A, Tab 15].

load growth could have been flattened with DSM. Several questioned the sudden increase followed by a tailing off of DSM savings that Manitoba Hydro anticipated under DSM Level 2,[249] as illustrated below:[250]



A witness for the Green Action Centre suggested that a spike then tailing off of DSM savings is unusual and that it appeared Manitoba Hydro was "reluctant to interfere with long-term construction plans."[251] Another expert, Dunsky Energy Consulting, presented more gradual scenarios with 1.5% incremental savings and stated they could be achieved at a cost much lower than new generation or export prices.[252]

As discussed in Chapter 1, by the time of the 2017/18 GRA (i.e., three years after the NFAT), Manitoba Hydro anticipated approximately 10 years of flat load growth with DSM[253] and an almost 10-year delay in the need date for new resources.[254] With minimum 1.5% DSM savings per year now legislated under The Efficiency Manitoba Act, domestic load is not expected to grow until at least 2035[255] and new resources will not be needed for the foreseeable future. It thus appears that the NFAT Panel was correct: Manitoba Hydro's DSM analysis during the NFAT was not accurate, thorough, reasonable, nor sound.[256]

Finding #3.8: If a more accurate, thorough, reasonable, and sound DSM analysis was incorporated, the NPV analysis of the plans would have been very different and Keeyask would likely have only been justifiable under a deferral scenario, if at all.

249 NFAT Report, p. 78 [Appendix A, Tab 15].
250 NFAT, Exhibit MH-202 [Appendix A, Tab 103].
251 NFAT, Transcript, p. 9838 [Appendix A, Tab 104].
252 NFAT, Exhibit CAC-62, pp. 13-14 [Appendix A, Tab 105].
253 2017/18 GRA, PUB-42-4, p. 9 [Appendix A, Tab 55].
254 2017/18 GRA, Transcript, p. 1220 [Appendix A, Tab 56].
255 *The Efficiency Manitoba Act*, CCSM c E15, ss 2, 7(1); *Efficiency Manitoba Regulation*, M.R. 119/2019, s. 2; Manitoba Hydro, 2018 Electric Load Forecast, p. 8 [Appendix A, Tab 57].
256 NFAT Report, pp. 33, 91 [Appendix A, Tab 15].

Recommendation #3.8: As noted in Chapter 1 of this report, the Commissioner concurs with the PUB's call for a comprehensive and regularly occurring IRP process in which DSM would be evaluated as a stand-alone resource and placed on an equal footing with other energy resources options.

Socio-economic Benefits

Impact Analysis of the PDP

As previously indicated in this chapter, Manitoba Hydro estimated the economic impacts of each component of the PDP (including Keeyask) for Manitoba and the rest of Canada. To do so, it applied the input-output model used by the Manitoba Bureau of Statistics to estimate the direct, indirect, and induced effects associated with project spending and the jurisdiction in which the effects would accrue.[257]

TyPlan, an independent expert in the NFAT process, used an alternative Statistics Canada interprovincial input-output model to assess the economic impact associated with the construction of Keeyask. TyPlan noted that both that model and the model used by Manitoba Hydro are reasonable. TyPlan's analysis largely confirmed the magnitude of total economic impacts, but estimated that a greater proportion of the employment and income created would be captured within Manitoba.[258]

The Commission heard from some KCN partners about the economic benefits of Keeyask, both as projected and as realized to date. The Commission heard from these partners that the projected level of estimated benefits from investing in the Keeyask project as equity owners was a crucial factor in their respective decisions to sign the JKDA, but that the projected level of these benefits has since declined significantly as a result of project cost overruns and changes in the export market. Given this significant decline, the Commission heard that the economic terms and revenue sharing formulas in the JKDA would have to be renegotiated for KCN partners to receive the long-term economic benefits that they expected from Keeyask.[259]

In terms of socio-economic benefits in the form of training, employment, and business opportunities for KCN partners, the Commission heard that the benefits have been positive and generally consistent with targets and expectations.[260] However, the Commission heard some concern that while the targeted number of members were employed, the number who were employed in trade positions that required past experience was disappointing, as was the fact that no KCN members have gained full-time employment with Manitoba Hydro as a result of the project construction process.[261]

Finding #3.9: Manitoba Hydro's assessment of the benefits of Keeyask for KCN partners appears to have been overly optimistic. Unreasonable project cost estimates and export market forecasts resulted in projected levels of economic benefits that have declined significantly from levels that KCN partners expected when they signed the JKDA. This has resulted in at least some KCN partners wanting to renegotiate the economic terms and revenue sharing formulas in the JKDA so that they may receive the long-term economic benefits that they expected from Keeyask.

257 Manitoba Hydro, NFAT Submission, Appendix 2.3: Economic Impact Assessment, p. 1 [Appendix A, Tab 94]; NFAT Report, p. 212 [Appendix A, Tab 15].
258 NFAT, Exhibit TyP-1, p. 26 [Appendix A, Tab 106].
259 Information received from participant, September 18, 2020; Information received from participant, September 25, 2020.
260 Information received from participant, September 18, 2020; Information received from participant, September 25, 2020.
261 Information received from participant, September 18, 2020.

Need for Direction on How Projects should be Assessed

During the NFAT, there were numerous criticisms of Manitoba Hydro's socio-economic analysis that highlight the need for government direction on how Manitoba Hydro's capital projects should be assessed. For example:

- Limited analysis of other options, including DSM and natural gas: The NFAT Panel heard concerns that Manitoba Hydro's approach only included a socio-economic evaluation for a small number of development plans.[262] Aside from the very general qualitative overview of resource technology options, no aspects of the socio-economic impacts of DSM or wind received any attention. Manitoba Hydro's analysis focused on the socio-economic impacts of the PDP and an MA-BCA restricted to four development plans that included only Keeyask and gas.[263] The consideration of natural gas was also limited, in part, by the Government's sustainable development and energy policies.[264] The Commission heard concerns that Manitoba Hydro did not provide a thorough, complete evaluation of a natural gas option.[265]
- Transfers to Government: The PDP provided the Government with the most revenue under all scenarios, given that it would use the most water, most capital, and most debt of all the plans.[266] The NFAT Panel stated that the higher benefits to the Government had to be balanced against the higher costs to ratepayers resulting from the PDP and the potential economic drag that could result from higher rates (including its effects on the competitiveness of companies in Manitoba).[267]

The NFAT Panel concluded that the limited analysis undertaken by Manitoba Hydro of plans other than the PDP supported the view that the socio-economic benefits of hydro-based plans compared favourably with those based primarily on gas generation. It reached this conclusion "largely due to the scale of construction expenditures involved."[268]

Finding #3.10: The NFAT Panel's assessment of socio-economic impacts highlights the different types of benefits and impacts that a major project can have, and the need for clear direction from government on how these types of projects should be assessed. For example, if the priority is meeting energy demand at the lowest cost, the number of construction jobs should be a peripheral consideration. Alternatively, if the priority is maximizing overall benefits to Manitobans, the number of construction jobs should be one of the considerations.

Recommendation #3.9: As noted in Chapter 2 of this report, the Government should clarify Manitoba Hydro's mandate in selecting projects to meet future energy demand. If Manitoba Hydro's primary focus should be on impacts to ratepayers (as recommended by the Commissioner in Recommendation #2.11), then many "benefits" from the perspective of government should actually be assessed as "costs" from the perspective of ratepayers. Under its current statutory mandate to provide adequate supply of power for the needs of the Province, a public and recurring IRP process provides a framework to determine those needs and select the right supply option to fulfill them.

262 NFAT, Exhibit MMF-26, pp. 7-8 [Appendix A, Tab 107].
263 NFAT Report, p. 211 [Appendix A, Tab 15].
264 Manitoba Hydro, NFAT Submission, Chapter 8: Determination and Description of Development Plans, pp. 1-2 [Appendix A, Tab 89]; NFAT Report, p. 28 [Appendix A, Tab 15].
265 Information received from participant, April 17, 2020.
266 NFAT, Exhibit MPA 3-1, pp. 28-29 [Appendix A, Tab 21].
267 NFAT Report, p. 226 [Appendix A, Tab 15].
268 NFAT Report, p. 227 [Appendix A, Tab 15].

BIPOLE III

Net Benefits Determined by Manitoba Hydro and Consistency with Best Practices

During GRAs after the NFAT, Manitoba Hydro explained the benefits of Bipole III in terms of reliability, namely that Bipole III would reduce the risk of weather events disrupting the transmission system and disconnecting southern Manitoba from hydroelectric generation in the north (as discussed in Chapter 1). Manitoba Hydro also explained that Bipole III would decrease the loss of load expectation to industry standards of 0.1 day per year.[269] However, Bipole III was never the subject of an NFAT.[270] There was never any independent analysis or review of its benefits, nor was there any process or assessment to determine whether the net benefits of Bipole III were determined in accordance with best practices.

The benefits of Bipole III were not determined through an IRP process, either. As noted above, the NFAT Panel concluded that Manitoba Hydro's failure to use IRP was contrary to best practices.

Finding #3.11: Given the scale and cost of Bipole III, the political decision by the former Government to exclude Bipole III from the NFAT and therefore from any independent assessment of benefits, costs, and overall justification is itself contrary to best practices. This finding is addressed by Recommendation #1.2.

Comparison to Net Benefits of Other Options

As noted above, Bipole III was never subject to an NFAT or equivalent independent review. Similarly, Manitoba Hydro never conducted a detailed assessment of the net benefits of Bipole III (as proposed) relative to other options.

In the EIS submitted to the CEC for Bipole III, Manitoba Hydro identified three alternatives to address the system reliability issues noted above.[271] Those three alternatives were: (1) Bipole III (western route); (2) 2000 MW of natural gas generation in southern Manitoba; and (3) 1500 MW of new imports from the U.S., plus 500 MW of natural gas generation in southern Manitoba.[272]

269 2014/15 GRA, Exhibit MH-57 [Appendix A, Tab 108]; 2017/18 GRA, Exhibit MH-125 [Appendix A, Tab 109].
270 Bipole III was expressly excluded from the scope of the NFAT: NFAT Report, pp. 39, 261 [Appendix A, Tab 15].
271 EIS, Chapter 2, p. 2-8 [Appendix A, Tab 26].
272 EIS, Chapter 2, p. 2-9 [Appendix A, Tab 26].

The table below identifies the objectives that Manitoba Hydro used to assess Bipole III (western route) and the two alternative options, as well as Manitoba Hydro's summary of its evaluation of each option having regard to these objectives.[273]

Objectives	Alternative 1 North-South dc Transmission	Alternative 2 Manitoba Natural Gas fired Generation	Alternative 3 Importing Power
Cost	Capital Cost (in-service dollars) $3.28 billion Fixed and variable annual cost $0.01 billion/yr	Capital cost amounts to $696 million more than Alternative 1 (Bipole III) on a present value basis Gas turbine installation cost $2.99 billion (in-service $) Fixed and variable annual cost $0.181 billion/year + variable costs	Capital Cost approximately $4.49 billion (in-service $) Annual costs subject to contract terms and variable costs
Savings/costs additional to the above	Reduction in transmission losses – approximately 26 M/year (2010$)	Annual cost of maintaining standby readiness	
Minimize unserved load during an extended HVdc outage	Meets reliability requirements until 2025. In the early years additional capacity available over the peak demand can reduce the import requirement costs	Meets reliability requirements until 2025 But heavily reliant on import from inception in 2017	Meets reliability requirements until 2025 Very high import dependency
Minimize costs to Manitoba Hydro during an extended HVdc outage	No additional costs	Significant fuel, operation and maintenance cost	Significant power purchase costs
Minimize costs to Manitoba Hydro during non-a catastrophic outage of HVdc	No additional costs	Fuel, operation and maintenance cost	Power purchase costs
Facilitate future system expansion and operational flexibility	Facilitates a reliability solution and an outlet for northern hydro development as soon as 2017	Provides only the reliability solution	Provides reliability solution and future potential for expansion of export access to US market

Having regard to the objectives identified in the table and the limited information used to evaluate them, Manitoba Hydro concluded in the EIS that Alternative 1 (Bipole III West) was "clearly the superior reliability solution at the least capital cost."[274]

273 EIS, Chapter 2, p. 2-14 [Appendix A, Tab 26].
274 EIS, Chapter 2, p. 2-13 [Appendix A, Tab 26].

It should be noted that a motion was brought during the CEC hearing by the Bipole III Coalition to compel Manitoba Hydro to respond to information requests on Bipole III needs and alternatives. However, the motion was dismissed based on a letter from the Minister stating that the CEC was not asked to conduct an NFAT for Bipole III, as follows:

> Thank you for your August 21, 2012 letter requesting clarification of the Terms of Reference for the CEC's review of Manitoba Hydro's Bipole III Transmission Line Project. In response to your specific questions about a Needs For And Alternatives To (NFAAT) review, the Terms of Reference, which were issued in December 2011, do not include instructions for the CEC to conduct an NFAAT.[275]

It should also be noted that the above analysis in the EIS did not consider Bipole III East, which was discussed in Chapter 1 of this report. Prior to the CEC hearing, in 2008 the PUB provided high-level comments about the relative merits of Bipole III West relative to Bipole III East. The PUB noted that Bipole III West would cause an additional line loss of up to $181 million due to the increased distance of the route,[276] and that the increased cost of Bipole III West would reduce otherwise expected export profits.[277] It also noted that Bipole III West would be less capable of providing the reliability benefit that Manitoba Hydro cited in order to justify Bipole III, as follows:

> Evidence presented at the recent hearing suggested that a repeat of the September 1996 failure of Bipole I and II, once Bipole III is in operation, built on the west side of the Province, would have more serious consequences if the interruption occurred during peak load. While an East Side Bipole III could function in parallel with existing Bipoles I and II, and in the event of the outage of both, make use of Bipoles I and II converters as well as the new Bipole III converters to provide 3,000 MW to the south, a West Side Bipole III would be limited to using only its own converters and thus could only provide the South with 2,000 MW in such a situation.[278]

275 Decision of the CEC on the Motion of the Bipole III Coalition, August 29, 2012 [Appendix A, Tab 27].
276 PUB Order No. 116/08, pp. 141-142 [Appendix A, Tab 33].
277 PUB Order No. 116/08, p. 165 [Appendix A, Tab 33].
278 PUB Order No. 116/08, pp. 142 [Appendix A, Tab 33], as cited in PUB Order No. 59/18, pp. 94-95 [Appendix A, Tab 34].

Following the CEC hearing (and after Bipole III West had received regulatory approval),[279] several experts compared the net benefits of Bipole III (western route) to other possible options. For example, in 2016, BCG performed a review of Bipole III alternatives for the MHEB. BCG considered the same two alternatives as the EIS, along with Bipole III East. It concluded that Bipole III East was likely the lowest-cost option but that it was refused by the Province, so Bipole III West was the next lowest-cost option.[280] The BCG review of alternatives to Bipole III included limited and similar information as the EIS (i.e., the numbers in the analysis of alternatives were essentially the same), as can be seen from the excerpt below:[281]

Bipole III East the most favourable option

But refused on environmental grounds

	Lowest cost, not selected **Bipole III East**	*Selected option* **Bipole III West**	**All-gas**	**Import + gas**
Description	**Alternative access to northern hydro** • 2000MW line • Could stage (line first, conv. stations later[1])	**Alternative access to northern hydro** • 2,300MW line • Cannot stage line and converter stations	**Backup generation** • 2000MW gas in the South	**Import line + backup generation** • 1500MW US line • 500MW gas
Cost estimate used in 2011 EIS[4]	Not formally assessed but estimated to be $900m less expensive • Staged converter station build • 700-900km shorter	~$3.3B (capital cost in-service dollars) ~$10M/y annual cost	~0.7B more than BPIII on PV[2] basis ~$3B gas turbine ~$181M/y pipeline reservation fee + variable costs	~$4.5B (capital cost in-service dollars) Annual costs subject to contract terms and variable costs
Additional benefits	**$28M/yr from reduced losses[3]** **Additional capacity for new hydro**	**$26M/yr from reduced losses[3]** **Additional capacity for new hydro**	**More dependable energy**	**Larger import/ export potential** **More dependable energy**
Risks	**Route through Boreal forest**	**No specific risk**	**Environmental risk, pipeline reservation fee**	**Environmental risk, future price of securing capacity**
Verdict	✗ **In 2007 the province directed MH to study Western routes**	✓ **Lowest cost of available options**	✗ **Higher cost, CO_2-emitting**	✗ **Higher cost, CO_2-emitting, difficult to secure US partner**

1. Line primary concern, given low probability of Dorsey destruction. 2. Present Value. 3. Current Bipole I&II transmission losses 8.6%; Bipole III West 6.4% to 7.0%; Bipole III East 6.0% to 6.4%.
4. Environmental Impact Statement (2011)
Source: Manitoba Hydro, BCG analysis

In its report submitted during the NFAT, WRA also discussed the alternatives to Bipole III that were outlined in Manitoba Hydro's EIS. WRA noted that Bipole III would offer no additional generating capacity, but the two alternatives would, which should have been a consideration when comparing the options, but was not:

> The addition of Bipole III brings with it no additional generating capacity, except for a reduction in losses of approximately 90 MW (see NFAT Chapter 4 at 44) … By comparison, each of the two alternatives would have provided 2000 MW of ADDITIONAL generating capacity. The alternatives were determined to be more expensive than Bipole III in large part because they included either (i) 2000 MW of additional firm gas-fired generation in Manitoba or (ii) 1500 MW of firm purchases from the United States plus 500 MW of additional gas-fired generation in Manitoba … In order to make the three alternatives comparable in terms of generating capacity, Manitoba Hydro should have added the costs of Keeyask and Conawapa to the cost of Bipole III ... [282]

279 NFAT Report, p. 27 [Appendix A, Tab 15].
280 BCG, "Bipole III, Keeyask and Tie-Line Review," September 19, 2016, pp. 4-5 [Appendix A, Tab 28].
281 BCG, "Bipole III, Keeyask and Tie-Line Review," September 19, 2016, p. 11 [Appendix A, Tab 28].
282 NFAT, Exhibit MMF-14, p. 36 [Appendix A, Tab 110].

WRA also stated that there were flaws in the analysis of the new imports option specifically, as 1500 MW of firm purchase commitments would not be required, as stated by Manitoba Hydro:

> … there would be no need for Manitoba Hydro to line up 1500 MW of firm purchase commitments to cover a simultaneous outage of Bipoles I and II that was estimated to occur no more frequently than once in 17 years. Nevertheless, this alternative was rejected in large part because Manitoba Hydro contended that reliance on additional import capacity would require that, in addition to Manitoba Hydro's building the line to the United States, it would need to line up 1500 MW of costly long term firm power purchase contracts tied to the cost of gas generation …
>
> In my experience, that contention is inconsistent with industry custom and practice. The right of Manitoba Hydro to rely upon interconnected utilities for support during contingencies – especially such extreme contingencies as outages of four poles of the Bipole HVDC system – is implicit in the interconnection process and is almost always made explicit in the bulk power contractual arrangements that accompany and govern such interconnections .. [283]

During the 2017/18 GRA, the PUB considered the September 20, 2007 letter (discussed in numerous parts of this report) in which then-Minister Greg Selinger told Vic Schroeder, then Chair of the MHEB, that the Government of Manitoba "did not regard an east side Bipole III as being consistent" with certain commitments and initiatives listed in that letter.

Based on its review of the 2007 letter from then-Minister Selinger, the PUB concluded that "as a result of a policy decision by the provincial Government, the routing of Bipole III was changed to a western route (Bipole III West) at an additional cost of approximately $900 million. This decision created a $900 million burden for ratepayers with no apparent technical benefit for the new route."[284]

Finding #3.12: It appears that the comparisons of the All Gas option to Bipole III did not account for the fact that the former would include 2000 MW of additional generation in Manitoba along with associated revenues, unlike Bipole III. It is also questionable that the new imports alternative to Bipole III required 1500 MW of firm purchase commitments, as stated by Manitoba Hydro. These shortcomings unfairly biased Manitoba Hydro's analysis against these alternatives to Bipole III.

Finding #3.13: As noted by BCG and discussed in Chapter 1 of this report, Bipole III East was a better option from an economic and technical perspective than the west-side route that was ultimately constructed. However, a political decision communicated in 2007 by then-Minister Selinger effectively vetoed this option and mandated a western Bipole III route over any other alternatives, such as a natural gas option. At this point the selection of a Bipole III (west) option was a *fait accompli*.

Finding #3.14: The costs and benefits of Bipole III West, and their comparison to other possible options, were not closely scrutinized to ensure that Bipole III West was superior to other options. This finding is addressed by Recommendation #1.2.

283 NFAT, Exhibit MMF-14, pp. 36-37 [Appendix A, Tab 110].
284 PUB Order No. 59/18, pp. 30, 181 [Appendix A, Tab 34].

SOUNDNESS OF EXPORT MARKET FORECASTS

As part of its resource planning process leading up to the NFAT, Manitoba Hydro sought the opinion of a number of independent price forecast consultants whose perspectives formed Manitoba Hydro's consensus electricity price forecast. Each of the consultants engaged by Manitoba Hydro used an electricity price forecast model capable of simulating the expansion and operation of the power system over a period of time based upon forecasts of inputs and load demands. Key inputs into these models included: characteristics of the existing generation fleet; characteristics of the load (including growth); forecasts for thermal fuel costs; characteristics of new generation that could be built; and forecasts for emissions allowances for thermal generation.[285]

During the NFAT, an independent expert developed its own export price forecast, which was generally lower than the export price forecast prepared by Manitoba Hydro's consultants.[286]

The NFAT Panel reviewed the reasonableness of Manitoba Hydro's export price forecast in light of the evidence that was submitted by all parties in the NFAT. While the NFAT Panel had confidence in Manitoba Hydro's contracted firm export revenues of $6.9 billion from 2015 to 2036, it did not have confidence in its export forecasts beyond that. The NFAT Panel expressed concerns that Manitoba Hydro had no export contracts that extended past 2036, and that future export contracts might not attract the premium pricing that Manitoba Hydro assumed for 100% of its dependable energy.

The NFAT Panel was less concerned about Manitoba Hydro's lack of export contracts that extended past 2036 if only Keeyask was built (and not Conawapa), since domestic load and the existing signed contracts were expected to consume Keeyask's dependable output prior to 2036.[287] However, as discussed in Chapter 1, domestic load is no longer expected to consume Keeyask's dependable output prior to 2036. Furthermore, the largest export contract that was signed at the time of the NFAT and factored into the $6.9 billion figure cited by the NFAT Panel was the WPS 308 MW contract; it was cancelled after the NFAT once Conawapa was put on hold.[288]

The NFAT Panel also found Manitoba Hydro's export price forecasts to be overly optimistic to the extent that they included a "carbon premium," around which there was considerable uncertainty and failing which export prices would be 20% to 25% lower than projected by Manitoba Hydro. Finally, the NFAT Panel noted that other technology such as distributed generation could result in dramatic decreases in market prices.[289]

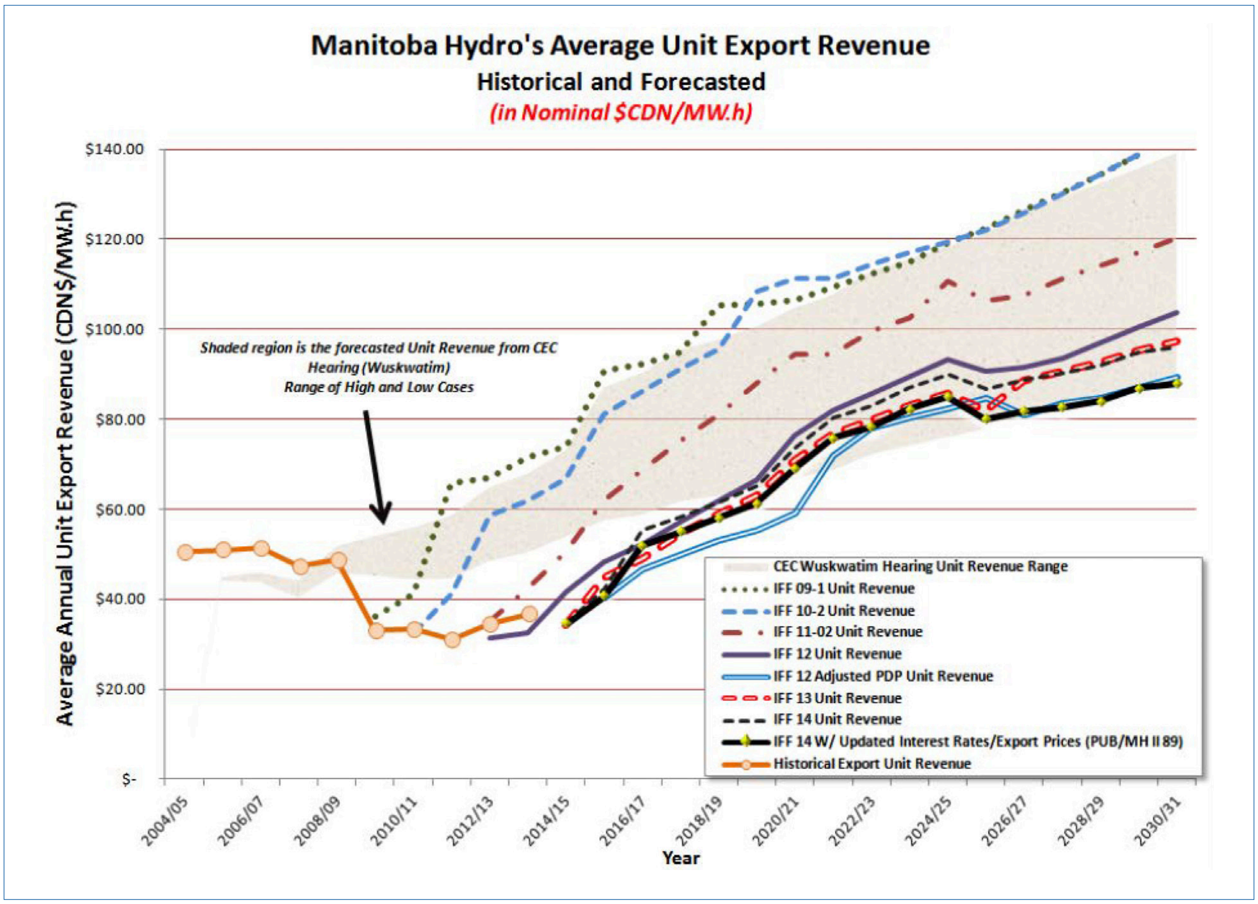
Both before and after the NFAT, the PUB consistently questioned Manitoba Hydro's export price forecasts, as shown in the examples below:

- Order No. 32/09: "the Board remains concerned that on an overall basis MH's 20-year forecasts may seriously overstate likely export revenues";[290]
- Order No. 99/11: "the Board fears that MH has both understated the costs of its preferred development plan and overstated future export sales revenue, with the result potentially being a compound overall increase in domestic rates over the twenty year period twice that forecasted by MH";[291]

285 Manitoba Hydro, NFAT Submission, Appendix 9.3: Economic Evaluation Documentation, p. 8 [Appendix A, Tab 111].
286 NFAT, Exhibit POT-2, p. 5 [Appendix A, Tab 112]; NFAT Report, p. 106 [Appendix A, Tab 15].
287 NFAT Report, p. 115 [Appendix A, Tab 15].
288 The WPS 308 MW contract had a termination clause that allowed WPS to cancel it if Conawapa was not built: NFAT Report, p. 111 [Appendix A, Tab 15].
289 NFAT Report, pp. 31, 115, 117 [Appendix A, Tab 15].
290 PUB Order No. 32/09, p. 2 [Appendix A, Tab 113].
291 PUB Order No. 99/11, pp. 6-7 [Appendix A, Tab 14].

- Order No. 5/12: "The Board notes that MH has, to date, declined to provide any alternative IFF scenarios based on lower natural gas prices and the absence of CO2 emissions regulations. Overall the Board does not accept MH's export revenue forecasts to date as representing a realistic basis for determining the economic viability of the proposed new major generation and transmission facilities such as Keeyask, Conawapa and Bipole III."[292]
- Order No. 73/15: "The Board is concerned that successive Manitoba Hydro export price forecasts have been revised downward and consistently overestimate actual results. That trend continues since, according to IFF14, Manitoba Hydro expects a further price decline which will negatively impact the business cases for Manitoba Hydro's new investments in generation and transmission."[293]

The consistent downward revision of Manitoba Hydro's export price forecasts and overestimating of actual results (as referred to above in PUB Order No. 73/15) are shown in the figure below:[294]



A comparison of Manitoba Hydro's forecasts to actual export revenues is provided in **Appendix F**.

Further, it should be noted that both before and after the NFAT, the forecasts of independent price forecast consultants were consistently revised downwards.[295] This downward trend demonstrates that export prices were softening even before the NFAT, something that was not reflected in Manitoba Hydro's projections. The Commission heard from a former member of the MHEB that there were questions about declining export prices and their effect on the economics of Manitoba Hydro's PDP at least as early as 2011, but the reality was that money had already been sunk into Keeyask and

292 PUB Order No. 5/12, p. 83 [Appendix A, Tab 35].
293 PUB Order No. 73/15, p. 87 [Appendix A, Tab 53].
294 PUB Order No. 73/15, p. 86 [Appendix A, Tab 53].
295 2017/18 GRA Tab 3, pp. 15-16 [Appendix A, Tab 114]; PUB Order No. 73/15, p. 87 [Appendix A, Tab 53

Conawapa.[296] This reality incented Manitoba Hydro to proceed with those projects notwithstanding that their business case was apparently eroding.

The Commission also heard concerns that Manitoba Hydro's export projections were based on outdated forecasts for demand in the U.S. that did not adequately account for its "shale [gas] revolution"[297] and desire to become energy self-sufficient, and the low capital cost of constructing natural gas plants in the U.S. to meet energy needs in the short term.[298] As recent history shows, Manitoba Hydro's assumptions about natural gas-powered generation in the U.S. have not borne out.[299]

The Commission is also aware of articles from U.S. journals published in the 2010 to 2012 time frame (i.e., shortly before the NFAT and Bipole III approval) which suggested that export price forecasts and hopes for lucrative hydro exports ("Manitoba's oil") were overly optimistic. For example, one article noted that some states and regions in the U.S. depend on greenhouse gas intensive industries and infrastructure, do not have diversified energy sources, or depend on fossil fuel production and, therefore, would be opposed to any federal program on greenhouse gases.[300] Another article noted that opposition to carbon regulation appears strongest in states that use the most carbon-intense fuels and that carbon pricing efforts would likely be politically unpopular at the state and local level, at least in the context of utility rates.[301] These articles highlight the inherent risks and uncertainties underlying Manitoba Hydro's assumptions about carbon "premiums" and demand for hydroelectric power in the U.S. export market.

Further, the Commission heard that increased investments in energy efficiency slowed the rate at which U.S. energy demand increased, particularly after the 2008 to 2009 recession, which was not reflected in Manitoba Hydro's export forecasts.[302]

The same concerns about the failure of Manitoba Hydro's domestic load forecast to address the effects of potential structural changes that could greatly decrease demand (as discussed in Chapter 1) are also concerns about the export market forecasts from the NFAT.

Finding #3.15: Manitoba Hydro's export price forecast was overly optimistic and created risks that the forecast prices would not materialize over the long-term. It does not appear that these risks were adequately considered when choosing to proceed with Keeyask over other options that were less dependent on export sales. This finding is addressed by Recommendations #1.6 and #2.6.

Finding #3.16: As found in Chapter 1 of this report, Keeyask is being built (at least for the initial many years) for exports and its economics are thus subject to significant export market risk. Generation from Keeyask must compete in the export market with new technology, U.S.-based renewables, a stable, low price natural gas alternative, and an uncertain political environment. There are firm contracts in place that provide some protection for the near term, but there is no guarantee that they will be renewed at the current prices or for a significant period of time. Nor is there any certainty regarding opportunity sales prices. While domestic demand will likely grow to require Keeyask's generation capacity eventually, that will likely not be until well after 2037/38. Until that time, Keeyask will be at the mercy of the export market, the risk of which currently rests on the bottom line of Manitoba Hydro and its customers.

296 Information received from participant, March 10, 2020.
297 Information received from participant, February 26, 2020.
298 Information received from participant, March 25, 2020.
299 Information received from participant, March 25, 2020.
300 William R Montalvo, "Cracks on the Wall: Why States Should Be Allowed to Lead on Climate Change" (2010) 21:2 Fordham Envtl LJ 383 at 387 [Appendix A, Tab 115].
301 Michael P Vandenbergh & Jim Rossi, "Good for You, Bad for Us: The Financial Disincentive for Net Demand Reduction" (2012) 65:6 Vand L Rev 1527 at 1555 [Appendix A, Tab 116].
302 Information received from participant, February 26, 2020.

Risk and Fiscal Implications

> *"Klohn Crippen Berger noted that it had never seen a large civil works contract (like the GCC) structured as a cost reimbursable contract."*

INTRODUCTION

In accordance with section 4 of the Terms of Reference, the Commission inquired into the extent to which the Keeyask and Bipole III planning and approval processes of Manitoba Hydro and the Government, and any other applicable approval or review processes, appropriately

(i) evaluated the commercial risk associated with each project and the risks of the two projects proceeding concurrently;

(ii) assessed the allocation of the risks among those involved in the construction of the projects; and

(iii) considered the immediate and long-term fiscal implications of the projects for the Province and Manitoba taxpayers and Manitoba Hydro and its ratepayers.

This chapter presents the Commissioner's findings and recommendations from this inquiry.

COMMERCIAL RISK OF THE PROJECTS

Manitoba Hydro Internal Processes

2012 Presentation by Power Planning Division

A presentation from the Power Planning Division of Manitoba Hydro to the MHEB in September 2012[303] noted that new resources would be required to meet Manitoba load plus committed power sales by 2022/23. The presentation included the PDP with an in-service date of 2019/20 for Keeyask.[304] In addition to systemic risks that were identified as being associated with any development plan, the following major risks were identified with the PDP specifically, along with mitigation steps for most of them:

Major Risk with PDP	Explanation of Risk	Mitigation Steps
Regulatory processes	• Complex processes may cause delays to in-service dates for major facilities	• Extensive work with process managers and EIS preparation • Power sales agreements allowed for up to a two-year delay for regulatory approvals
Transmission Risk	• Risk of delay in Bipole III beyond 2017	• Option for a 230 kV interconnection in which MP would invest • Power sales agreements allowed for up to a two-year delay for regulatory approvals
Export Price Risk	• Significant uncertainty in future prices	• "Exhaustive process to develop responsible forecast" • Fixed price portions of long-term sales • Sensitivity analysis • Exploring use of scenarios for analysis of risk
Capital Costs	N/A	N/A

The same report notes that all risks are manageable and would be managed through annually updating assumptions and forecasts, frequent analysis, assessing the impact of variation from expected conditions, scenario analysis to evaluate risk, and a diversified portfolio of resources and contracts.

2015 Corporate Risk Management Report

Manitoba Hydro prepares an annual corporate risk management report for the MHEB, which provides information on major risks the corporation faces as it carries out its mandate. The most recent report that is publicly available and available to the Commission, the 2015 Corporate Risk Management Report, provides insight into Manitoba Hydro's commercial risk evaluation around the time of the Keeyask and Bipole III planning and approval processes. It contained high-level overviews of more than 40 discrete risks in a number of categories, including market, financial, infrastructure, and governance. The Commission has also reviewed a redacted version of Manitoba Hydro's 2014 Corporate Risk Management Report[305] which appears to be similar to the 2015 report, at least in terms of relevant information discussed below.

Under the "significant and emerging risk" category, the 2015 report noted that large initiative infrastructure investment can "challenge the Corporation's ability to meet Manitoba's energy needs while keeping rates affordable, and maintaining the Corporation's financial strength." This is clearly a reference to Manitoba Hydro's statutory mandate, which 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 [there]in." Proposed mitigation included best practices such as cost estimating, contracting, contingencies and reserves, preserving financial integrity, and managing stakeholder issues.[306]

The 2015 report also placed financial strength under the "significant and emerging risk" category, and noted that large capital investments weaken financial targets and careful management is necessary to mitigate the risk of exposing ratepayers to increases in the event of droughts or outages.[307] Specifically, the report noted that large projects, including Bipole III and Keeyask, are likely driving a forecast drop in Manitoba Hydro's equity ratio to 12% by 2021/22 (IFF15), before recovering to 25% by 2031/32[308] (the same timeline presented during the NFAT, as discussed later in this chapter[309]). Proposed mitigation of financial strength risks included continued cost containment; pursuit of export sales; controlling finance expenses; and reasonable and predictable rate increases.[310]

The 2015 report noted that Manitoba Hydro "is prepared to accept weaker financial ratios during the period of significant capital investment in order to spread the recovery of costs from customers over a longer period of time and minimize the impacts to customer bills. However, it will be necessary for Manitoba Hydro to demonstrate progress towards attaining its financial targets to credit rating agencies and other stakeholders over the long term."[311]

Finally, the 2015 report noted "strategic direction and execution" as a significant and emerging risk, including planning assumptions that are not realized, or strategies not executed as required. The integrated planning cycle and IRP were specifically mentioned under the risk treatment associated with this risk, but no further related details were included.[312]

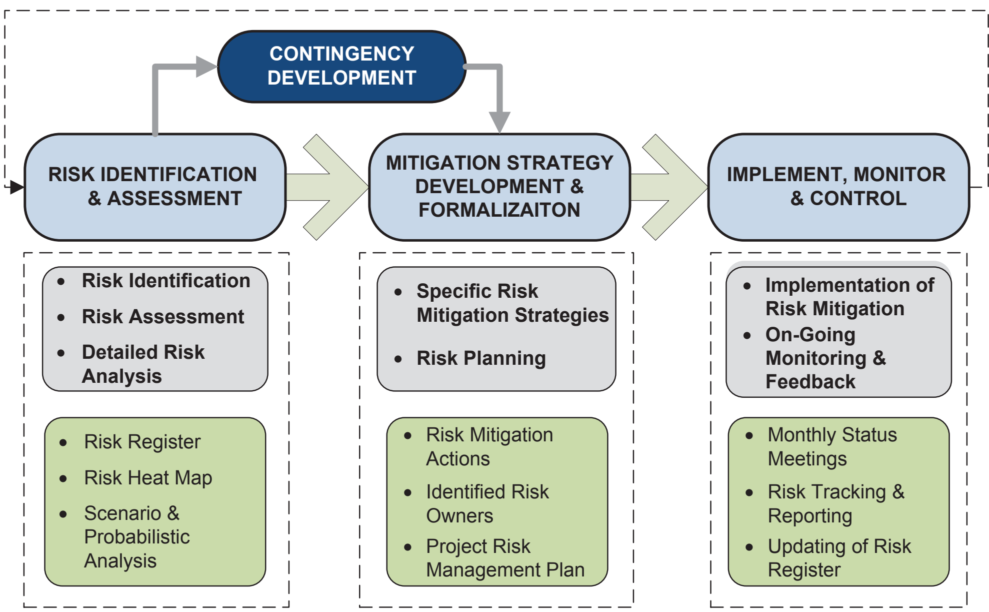
305 2014/15 GRA, Appendix 11.7 [Appendix A, Tab 117].
306 2017/18 GRA, PUB Minimum Filing Requirement (MFR) 9 ("**MFR** 9"), pp. 7-8 [Appendix A, Tab 118].
307 MFR 9, p. 8 [Appendix A, Tab 118].
308 MFR 9, p. 55 [Appendix A, Tab 118].
309 As discussed later in this chapter, Bipole III and Keeyask have driven a drop in Manitoba Hydro's equity ratio that now will likely not recover to 25% until after 2035/36.
310 MFR 9, pp. 8-11 [Appendix A, Tab 118].
311 MFR 9, p. 55 [Appendix A, Tab 118].
312 MFR 9, p. 91 [Appendix A, Tab 118].

The 2015 report did not contain a detailed analysis of the aggregate risks associated with the PDP, nor did it include a separate review of the Bipole III or Keeyask projects. It also did not include a comprehensive and detailed risk mitigation strategy; rather, it included individual strategies for each of the discrete risks identified.

Risk Register

During the planning and approval phases of the Bipole III and Keeyask projects (and construction), risks were identified in a risk register that Manitoba Hydro prepared for each project as part of its risk management process. In its NFAT submission, Manitoba Hydro provided the following graphic of its risk management process:[313]

Capital Project Risk Management Process



Risk assessment, and the role of the risk register in that process, were described as follows:

> Risk assessment is the process of identifying risk items that influence/drive uncertainty on the project; these risk items are captured in a project risk register, a living document that acts as the repository for all identified project risks throughout the life of the project. The impact and probability for each risk event is scored, allowing identified risks to be prioritized based on a risk score (impact x probability) to help focus risk management activities on the most critical items.[314]

The risk register includes information about the risk "owner" and mitigation measures for each identified risk,[315] in addition to information about the impact and probability of each identified risk materializing. The risk register is updated on an on-going basis throughout the life of the project to reflect the current risk forecast, including by closing risks that have passed, adding any newly identified risks, and updating probability and impact assessments.[316]

313 Manitoba Hydro, NFAT Submission, Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan, p. 35 [Appendix A, Tab 119].
314 Manitoba Hydro, NFAT Submission, Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan, p. 35 [Appendix A, Tab 119].
315 2017/18 GRA, Exhibit MH-130, p. 46 [Appendix A, Tab 120].
316 2017/18 GRA, Information Request (IR) PUB/MH II-64a-b [Appendix A, Tab 121].

Categories of risk that were listed in the Keeyask risk register at the time of NFAT included concrete and earth structures, electrical and mechanical work, electrical power systems and generation, environmental, excavation, geotechnical, infrastructure, licensing, and project management.[317] The top four Keeyask project risks identified in the risk register at that time were:

- Inability to attract/retain labour due to competition for qualified resources from other Manitoba Hydro Projects (i.e., Bipole III), national projects, and aging construction workforce;
- Insufficient Construction Management Resource Budget due to external resources required at a higher cost due to the inability to attract internal resources for short durations;
- Escalation due to market conditions; and
- Skilled labour shortage resulting in an increase of labour hours to complete construction activities.[318]

While none of the above-listed "top risks" materialized, the following "very high" risks in the Keeyask risk register did materialize and were identified as the three biggest risks during the 2017/18 GRA:

- Labour productivity (including the experience level of the workforce and the contractor's productivity rates assumed within the tender);
- Weather (including record high river flows, formation of stable ice cover in the winter); and
- Geotechnical/geological conditions more challenging than planned (including boreholes not representative of actual site conditions for excavation and borrow pits).[319]

By contrast, none of the "very high" risks in the Bipole III risk register materialized. The only risk in that register that had a financial impact of greater than $20 million or a schedule impact of greater than six months was "[u]nforeseen geotechnical conditions in the HDVC converter area and obstructions encountered during the installation of the AC switchyard area at Keewatinohk Converter Station."

While the Keeyask and Bipole III risk registers have been treated confidentially during PUB proceedings, Knight Piésold reviewed the Keeyask risk register during the NFAT[320] and MGF Project Services ("**MGF**") reviewed the Bipole III risk register during the 2017/18 GRA, as part of their respective scopes of work. The reviews of these two independent expert consultants are discussed later in this chapter.

As noted in Chapter 2, in 2016, BCG performed a review of the Bipole III, Keeyask, and Tie-Line projects for the MHEB. As part of its review, BCG evaluated the prudency and risk associated with Manitoba Hydro's investments to build these projects. In the report summarizing the results of its review, BCG noted that Bipole III and Keeyask should have been evaluated together along with the tie-line, instead of individually, in order to properly assess the collective risks of conducting all projects at once. Specifically, the report noted that Keeyask (and the tie-line) were dependent on construction of Bipole III and that "separate reviews of the projects was not the best choice given their inherently interconnected nature."[321]

During the 2017/18 GRA, Manitoba Hydro submitted a December 2016 report from UMS Group, who it engaged to assess its asset management capabilities. In its report, UMS group noted that risk is a key basis for decision making in a best practice asset management system, and that Manitoba Hydro was increasingly incorporating risk into its asset-related decisions. However, it also noted that guidance on

317 NFAT, Exhibit KP-3-2, p. 8 [Appendix A, Tab 122].
318 2017/18 GRA, Information Request (IR) PUB/MH II-64a-b [Appendix A, Tab 121].
319 PUB Order No. 59/18, pp. 81-82 [Appendix A, Tab 34].
320 NFAT, Exhibit KP-3-2, p. i [Appendix A, Tab 122]
321 BCG, "Review of Bipole III, Keeyask and Tie-Line Project," September 19, 2016, p. 2 [Appendix A, Tab 22].

and attention to asset-related risk had not been provided from corporate leadership and that there was a lack of clear communication on acceptable risk tolerance, no corporate risk assessment standard or risk register addressing each asset class, and no formal process to regularly review risks identified by the business units to provide direction. It further noted that without risk assessment at the asset level (i.e., electric distribution assets or gas assets), rather than at the project level, "it's difficult to determine which risks need to mitigated, what opportunities exist to accept more risk (i.e., current risk is below tolerance level), and what strategies should be adopted to manage risk."[322]

Finding #4.1: Based on a review of Corporate Risk Management Reports from Manitoba Hydro from the period shortly following the NFAT, and overviews of the risk registers for Keeyask and Bipole III, it appears that Manitoba Hydro performed a detailed analysis of individual, discrete risks that were identified with respect to each project. However, it did not give due consideration to compound risk (i.e., the combination of two or more related risks) associated with each project, let alone with the projects together. These documents do not reveal a comprehensive risk mitigation strategy, either; rather, they include specific strategies for each of the discrete risks identified.

Recommendation #4.1: Manitoba Hydro should assess long-term risks and the compound risks of executing multiple projects together as part of the IRP process. For project-specific risk, the risk register should incorporate and address compound risk for the project. These changes would assist Manitoba Hydro in effectively identifying and managing risks.

Finding #4.2: The Commissioner agrees with BCG that Bipole III and Keeyask should have been evaluated together along with the tie-line, instead of individually, in order to properly assess the collective risks of executing all projects at once. Keeyask (and the tie-line) were dependent on the construction of Bipole III and conducting separate reviews of the projects was not the best choice given their inherently interconnected nature. One example of a factor that was not properly identified was the risk that a carbon price would not develop in the U.S. Given that the economic case for Keeyask relied on opportunity sales projections that assumed a new carbon price – and Bipole III was justified (at least in part) based on transmitting economic power from Keeyask – this factor should have been identified and assessed as a risk with respect to both projects. It was not.

Recommendation #4.2: The evaluation of risks of executing a project should include the risks associated with any other new project or new facility upon which it is dependent. For example, Keeyask was dependent on the construction of Bipole III. The assessment of Keeyask and of any other new generating station should include the risks associated with any new transmission project that is needed to transmit the power that it produces.

PUB Processes

Keeyask Cost Estimates

At the direction of the Cabinet, the NFAT terms of reference did not ask the PUB to review the risk of constructing Bipole III and Keeyask concurrently, and the PUB did not perform such a review.[323] Similarly, while the risk of Keeyask cost overruns was considered during the NFAT through Manitoba Hydro's economic uncertainty analysis,[324] the impact of Bipole III cost overruns was not considered.

322 2017/18 GRA, Appendix 5.1, pp. 7, 16-17 [Appendix A, Tab 123].
323 NFAT Report, pp. 39, 261 [Appendix A, Tab 15]; PUB Order No. 59/18, p. 35 [Appendix A, Tab 34].
324 Manitoba Hydro, NFAT Submission, Chapter 10: Economic Uncertainty Analysis, pp. 2-4 [Appendix A, Tab 92].

As discussed in Chapter 3 of this report, Manitoba Hydro's economic uncertainty analysis for Keeyask (and other development plans) during the NFAT examined a range of uncertainties around three factors: energy prices, discount rates used to calculate NPVs, and capital costs. A low, reference, and high range was developed for each of the three factors with probability weightings for each determined by Manitoba Hydro, resulting in 27 scenarios with varying NPVs and probabilities for various development plans. The biggest risk identified was capital cost increases, as shown below:[325]

March 10, 2014 Updated Probabilistic Quilt

		Development Plan	1	2	4	8	6	12	5	14
			All Gas	K22/Gas	K19/Gas24 /250MW	CCGT/C26	K19/Gas31 /750MW	K19/C31 /750MW	K19/Gas25 /750MW	K19/C25 /750MW
									WPS Sale & no WPS Inv	
Energy Prices	Discount Rates	Capital Costs	Millions of 2014 NPV Dollars							
Low	Low	H	-1062	-1401	-851	-1501	-1079	-2143	-758	-1825
		Ref	-68	16	646	106	392	-53	698	424
		L	734	1205	1898	1449	1613	1750	1906	2359
	Ref	H	-463	-1751	-1512	-2398	-1793	-3717	-1546	-3969
		Ref	208	-677	-334	-1085	-614	-1977	-355	-2010
		L	750	232	658	15	369	-476	637	-325
	High	H	-88	-1782	-1761	-2625	-2060	-4202	-1872	-4838
		Ref	416	-891	-748	-1480	-1033	-2668	-820	-3044
		L	823	-133	110	-519	-172	-1345	61	-1500
Ref	Low	H	-2033	-120	543	325	298	1410	-7	1869
		Ref	-1039	1296	2040	1932	1770	3501	1449	4118
		L	-237	2486	3292	3275	2991	5304	2658	6053
	Ref	H	-671	-585	-260	-910	-517	-1204	-707	-1345
		Ref	0	489	917	403	662	536	484	614
		L	542	1397	1910	1503	1645	2037	1477	2300
	High	H	17	-716	-620	-1343	-880	-2214	-1034	-2759
		Ref	520	175	393	-198	148	-680	18	-966
		L	927	933	1251	762	1008	643	899	578
High	Low	H	-3454	892	1647	2005	1333	4820	402	5388
		Ref	-2460	2309	3143	3612	2804	6911	1858	7638
		L	-1658	3498	4396	4955	4025	8714	3066	9573
	Ref	H	-1158	402	797	469	526	1178	-103	1125
		Ref	-487	1476	1974	1782	1704	2918	1088	3084
		L	55	2384	2967	2882	2687	4418	2081	4770
	High	H	-82	210	368	-156	115	-352	-384	-824
		Ref	422	1101	1381	989	1143	1182	669	969
		L	828	1859	2239	1949	2003	2505	1549	2513

In the March 2014 update to its economic uncertainty analysis (reflected above), Manitoba Hydro lowered the probability weightings for "high" capital costs from 30% to 20% based on its view that there would be increased cost certainty from the recently received GCC.[326]

During the NFAT, the PUB did not have confidence in Manitoba Hydro's Keeyask capital cost estimate.[327] It concluded that the actual construction cost of Keeyask would increase beyond Manitoba Hydro's projected capital cost (at the time) of $6.5 billion and that budgeting for its "high" estimate of $7.2 billion (at the time) would be prudent. The PUB reached this conclusion on the basis that the GCC was a cost reimbursable contract that left a significant portion of cost risk with Manitoba Hydro,[328] as discussed later in this chapter.

Finding #4.3: The fact that Manitoba Hydro <u>lowered</u> its probability weightings for "high" capital costs for Keeyask, based on what it viewed as increased cost certainty resulting from the GCC, raises serious concerns as to whether Manitoba Hydro fully understood the significant risks inherent in this type of cost reimbursable contract.

325 NFAT, Exhibit MH-104-8, p. 3 [Appendix A, Tab 91].
326 NFAT Report, p. 149 [Appendix A, Tab 15].
327 NFAT Report, p. 132 [Appendix A, Tab 15].
328 NFAT Report, pp. 132-133 [Appendix A, Tab 15].

Manitoba Hydro's "reference" capital cost estimates during the NFAT (including for Keeyask) were based on a P50 contingency level (i.e., there was a 50% chance of the project being over budget). Its "high" capital cost estimates were determined by adding a Management Reserve to the P50 contingency, to account for labour productivity problems and escalation costs higher than 2.5%.[329]

Knight Piésold reviewed Manitoba Hydro's approach to risk management during the NFAT (including the Keeyask risk register). While it found that Manitoba Hydro was following best practices, Knight Piésold suggested that a more risk-averse decision maker would use a P80 cost estimate (i.e., only 20% chance of the project being over budget), not a P50 cost estimate like Manitoba Hydro used,[330] and would apply a composite hydropower escalation rate of 3.1% to 3.4%, rather than the 2.5% applied by Manitoba Hydro.[331] Knight Piésold's recommendation for P80 cost estimates was supported by a former member of Cabinet.[332] Knight Piésold also expressed concerns about the risks associated with labour shortages, construction delays, and concrete work productivity, and thus concluded that the "amount of contingency carried for the two generation projects (Keeyask and Conawapa) could be considered insufficient depending on the use made of the capital cost estimates."[333]

The updated 2017 Keeyask cost estimates that were considered during the 2017/18 GRA included an $8.7 billion estimate and a $9.6 billion estimate. The $8.7 billion estimate (with a 21-month delay) incorporated a P50 contingency. The $9.6 billion estimate (with a 29-month delay) incorporated a P90 contingency (addressing 90% of risk outcomes).[334] During the 2017/18 GRA, MGF recommended that Manitoba Hydro carry the higher P90 figure, on the basis that the general contractor for Keeyask had "not made its planned progress for either 2016 or 2017 and continue[d] to plan work based on productivities it [did] not appear capable of achieving."[335]

MGF also opined that a complete re-estimate of the cost for Keeyask should have been performed as part of the pre-tender estimate, instead of simply adjusting previously prepared estimates to later points in time. This would minimize the risk of potential errors associated with adjusted estimates, which are generally prepared without fully updating certain variables (e.g., project scope, market conditions, foreign exchange rates, commodity indices, labour rates and composition, productivities, regulations, cash flow assumptions for escalation, and technologies). These variables are likely to change significantly over the course of several years, and the failure to fully update more frequently increases the risk of estimate errors. MGF further noted that any estimate inaccuracies are potentially further compounded over time and especially if the escalation itself is improperly calculated or the selected indices are inappropriate for the application.[336]

329 Manitoba Hydro, NFAT Submission, Chapter 15: Implementation and Risk Management Plan for Preferred Development Plan, p. 39 [Appendix A, Tab 119].
330 NFAT, Exhibit KP-4, p. 57 [Appendix A, Tab 124].
331 NFAT, Transcript, p. 6904 [Appendix A, Tab 125].
332 Information received from participant, October 21, 2020.
333 NFAT, Exhibit KP-3-1, p. i [Appendix A, Tab 122]
334 PUB Order No. 59/18, pp. 77-78 [Appendix A, Tab 34].
335 2017/18 GRA, Exhibit MGF-2, p. 69 [Appendix A, Tab 126].
336 2017/18 GRA, Exhibit MGF-2, p. 39 [Appendix A, Tab 126].

MGF also discussed the industry standard project "stage gate" approval process.[337] The PUB summarized this concept as follows:

> This is a project management tool, common in the energy industry, that shepherds a project through five phases: conception, concept selection, tendering, execution, and operation, with a decision gate following each phase. The 'stage gate' concept is that a project does not move from one stage to the next – that is, receive approval to go to the next stage – until a set of criteria is satisfied. The criteria may be technical, financial, commercial, or other criteria. In some cases, a peer review by engineering, commercial, and project management professionals is completed to ensure that the risks associated with the project are addressed. [338]

Finding #4.4: Manitoba Hydro consistently underestimated the costs of Keeyask. Further, its updated cost estimates did not fully account for changes in variables, including for escalation.

Recommendation #4.3: As a public utility whose performance affects the electricity rates paid by Manitobans and can have fiscal implications for the Province, Manitoba Hydro should design its cost estimates in a way that is more conservative to minimize the potential for cost overruns (as has occurred on Keeyask and, to a lesser extent, on Bipole III). These estimates should be as accurate as possible based on the project development stage and include a project contingency that is proportionate to the risks identified through a detailed risk evaluation for the project. At the time that the project is formally sanctioned, a P80 cost estimate should be developed by Manitoba Hydro, if possible, to better understand the risk of cost overruns.

Recommendation #4.4: Manitoba Hydro should use the industry standard "stage gate" approach for internal approvals of major projects like Keeyask and Bipole III. As part of this approach, there should be a "gate" at each major decision point during the project development process, whether that consists of a required internal approval from the MHEB, a decision that will result in significantly higher sunk costs, or a decision from which Manitoba Hydro will otherwise have difficulty returning (e.g., executing the GCC). This process should be designed with particular attention to the consideration and implementation of defined off-ramps so that the project can be stopped (e.g., once a certain amount of money has been spent on a project, before sunk costs are unreasonably high).

At each stage gate, Manitoba Hydro ought to re-evaluate the business case for the project to determine if such a case still exists, including an examination of whether the assumptions underlying that business case are still valid (e.g., domestic load and export market forecasts).

Bipole III Cost Estimates

The cost estimates for Bipole III also dramatically increased over time. This escalation reflected in Manitoba Hydro's CEFs has been depicted by the PUB as follows:[339]

Western Route Bipole III In-Service Cost Estimates - Capital Expenditure Forecast ("CEF") ($millions)

CEF06	CEF07 to CEF10	CEF11 to CEF12	CEF13	CEF14 to CEF15	CEF16
1,880	2,248	3,280	3,341	4,653	5,042

337 2017/18 GRA, Exhibit MGF-2, pp. 130, 133, 152 [Appendix A, Tab 126].
338 PUB Order No. 59/18, p. 247 [Appendix A, Tab 34].
339 PUB Order No. 59/18, p. 87 [Appendix A, Tab 34].

Bipole III cost estimates were considered during the 2017/18 GRA. The record of that proceeding showed that from 2006 to 2010, Manitoba Hydro's Bipole III estimates used HVDC converter equipment with outdated estimated costs from 2001 and those estimates did not include any contingency.[340]

Although it is not shown in the table above, in 2009 Manitoba Hydro staff prepared a revised Bipole III cost estimate of $3.95 billion, which included higher estimates of the converter costs using line-commutated converter ("LCC") technology and a $525 million project contingency. This estimate was approved by the Vice-Presidents of Transmission and Power Supply, but not by the Manitoba Hydro executive.[341]

The estimate was then adjusted downward to $3.28 billion and approved by Manitoba Hydro's executive for inclusion in CEF11. This lower estimate included voltage source conversion technology instead of LCC technology and substantial reductions in the project contingency, down $205 million (from $525 million).[342]

Manitoba Hydro's cost estimates increased to $4.65 billion (the final pre-construction budget) in October 2014 due to, among other reasons, the receipt of converter bids that were only willing to provide more expensive LCC technology converters and an increased P50 contingency (and new management reserve) following a "complete risk and contingency review" using the same process applied on Keeyask during the NFAT.[343]

The changes in the Bipole III contingency over time are shown in the table below:[344]

CEF06 to CEF10	2009 (Unapproved)	CEF11	CEF14
$0	$525 million	$205 million	$247.6 million

As noted above, the CEF14 estimate was a P50 cost estimate, notwithstanding Knight Piésold's prior observation in the NFAT that a P80 cost estimate would be more appropriate for a risk-averse decision maker. Manitoba Hydro subsequently included a higher P75 contingency estimate in its $5.04 billion CEF16 estimate for Bipole III in 2016.[345]

Finding #4.5: Similar to Keeyask, for Bipole III, Manitoba Hydro relied on cost estimates that were lower probability and higher risk than what were recommended by independent expert consultants. This finding is addressed by Recommendation #4.3.

340 PUB Order No. 59/18, p. 87 [Appendix A, Tab 34].
341 2017/18 GRA, PUB Minimum Filing Requirement (MFR) 155, Addendum #06 [Appendix A, Tab 30].
342 PUB Order No. 59/18, p. 88 [Appendix A, Tab 34].
343 2014/15 GRA, Information Request (IR) PUB/MH I-20a, p. 3 [Appendix A, Tab 127].
344 2017/18 GRA, PUB Minimum Filing Requirement (MFR) 155 [Appendix A, Tab 30].
345 2017/18 GRA, Appendix 5.4, p. 12 [Appendix A, Tab 128].

With respect to the CEF11 cost estimate (which was current as of Bipole III's regulatory approval), the PUB made a finding during the 2017/18 GRA that the development of it, its inclusion of non-LCC technology, and its contingency amounts represented an unreasonable risk on the part of Manitoba Hydro, as follows:

> The Board agrees with the Consumers Coalition that Manitoba Hydro undertook unreasonable risk when it developed its $3.28 billion Bipole III cost estimate in 2011. It appears that Manitoba Hydro had rejected its 2009 internal cost estimate of $3.95 billion, based on what was referred to as the "classic" LCC technology, in order to try to take advantage of new, unproven voltage source conversion technology. The Board finds that Manitoba Hydro compounded this risk by significantly reducing the contingency amounts. Exploring options to use new, improved technology should not be avoided. However, the Board concludes that when estimating costs for a project that includes new, unproven technology, the contingency amounts should be increased, not decreased as was done by Manitoba Hydro.[346]

As shown in the table above, no contingency ($0) was included in the official cost estimates of Bipole III for prior planning years, as represented in CEF06 to CEF10. Given the PUB's finding that Manitoba Hydro undertook unreasonable risk when it reduced contingency amounts in its CEF11 cost estimate for Bipole III, it must also be said that Manitoba Hydro undertook unreasonable risk when it included no contingency in its prior cost estimates.

Finding #4.6: Manitoba Hydro undertook unreasonable risk when it included no contingency in its Bipole III cost estimates in CEF06 to CEF10. Manitoba Hydro should have also accounted for a higher contingency amount in its subsequent CEF11 cost estimate to account for the fact that the project proposed to use new, unproven technology. The failure to do so is particularly concerning given that it was not addressed for three years (until a new estimate was prepared in 2014). For almost a decade, Manitoba Hydro repeatedly and consistently included contingency amounts in its Bipole III cost estimates that were unreasonably low. This finding is addressed by Recommendation #4.3.

Construction Contracts

Keeyask GCC

During the NFAT, the allocation of risks under the Keeyask GCC was discussed by the PUB as follows:

> The Keeyask general civil contract is a costs-reimbursable contract rather than a fixed price contract. This means that if volumes of materials increase, Manitoba Hydro is responsible for that increase. The NFAT Panel had the opportunity to consider the contract in camera as Commercially Sensitive Information, and has concluded that Manitoba Hydro bears a significant cost risk.[347]

346 PUB Order No. 59/18, p. 97 (emphasis added) [Appendix A, Tab 34].
347 NFAT Report, p. 30 [Appendix A, Tab 15].

Risks under the GCC that left Manitoba Hydro vulnerable to cost overruns on Keeyask were also commented on during the NFAT:

> The Keeyask general civil contract is a cost-reimbursable contract, not a fixed price contract. This leaves the contract vulnerable to cost escalations as a result of: quantity risk, especially in areas where quantities may have been underestimated; escalation to the contractor's cost factors due to labour productivity or labour costs; escalation in the cost of supply and equipment; and challenges related to adverse weather conditions.[348]

The allocation of risks through a cost reimbursable contract, as opposed to a fixed or unit price contract, is outlined in the table below, along with a description of each payment structure:[349]

Structure	Description	Contractor's Risks	Owner's Risks
Cost reimbursable-target price	Contractor is paid for its costs for material and direct labour, plus profit and general administration and overheads. Profit erodes if the target price is exceeded and increases if the actual cost is below target price.		• Quantities • Productivity • Inefficiency of the contractor
Fixed price (i.e., lump sum)	Contractor is paid a fixed price regardless of the costs it incurs or the duration of the project.	• Quantities • Productivity	
Unit price	Contractor is paid a pre-defined unit rate (or rate per quantity) multiplied by the quantity of work (e.g., per m3 of earth excavation or concrete placement).	• Productivity	• Quantities

While Manitoba Hydro is accountable for the above risks associated with a cost reimbursable payment structure, it is the GCC contractor that leads and manages the activities that trigger these risks.[350]

By the time of the 2017/18 GRA, the risk of cost overruns had already been (partially) realized, which resulted in a 34% increase in Manitoba Hydro's cost estimate for Keeyask (up to $8.7 billion).[351]

Finding #4.7: The PUB noted the "significant cost risk" and "vulnerab[ility] to cost escalations" because of the Keeyask GCC during the NFAT, yet recommended the project for approval, nonetheless. It may not have understood the scope of this risk and/or, as the Commission heard repeatedly in interviews, its recommendation may have been influenced significantly by the reality and quantum of already sunk costs for the project ($1.2 billion).

Finding #4.8: Despite the risks stemming from the GCC that were identified during the NFAT, there is no evidence that Manitoba Hydro subsequently attempted to mitigate those risks (e.g., by renegotiating the GCC) until 2016 when those risks had already begun to materialize. This suggests that either Manitoba Hydro did not understand the risks, despite their clear articulation in the NFAT Report, or it did not know how or have the capacity to manage them.

The commercial terms of the GCC were considered in detail during the 2017/18 GRA. During that proceeding, several aspects of the GCC were identified that were not effectively considered by Manitoba Hydro and left it (and, by extension, ratepayers) exposed to risk. Those aspects were its cost

348 NFAT Report, p. 123 [Appendix A, Tab 15].
349 PUB Order No. 59/18, pp. 73-74 [Appendix A, Tab 34].
350 2017/18 GRA, Exhibit MGF-2, p. 161 [Appendix A, Tab 126].
351 PUB Order No. 59/18, p. 77 [Appendix A, Tab 34].

reimbursable payment structure, the pain/gain formula tying the contractor's profit to the target price, and the general contractor's productivity levels, each of which are discussed in more detail below.

Cost reimbursable payment structure: Manitoba Hydro's view was that, in 2012 when the procurement process was underway, contractors would not have been receptive to a "hard money" (i.e., fixed or unit price) contract that transferred many risks to them. This led to a cost reimbursable contract. This was explained during the 2017/18 GRA as follows:

> In order to understand the context surrounding the decision to proceed with the general civil contract as a target price contract, we need to rewind the clock back five (5) years to 2012 when the procurement process was underway. At that time oil prices exceeded a hundred dollars per barrel and the North American megaproject market was hot, with dozens of capital expansion projects taking place in northern Alberta as well as LNG projects across the country.
>
> In that environment megaproject contractors were not accepting hard money contracts where many risks such as labour productivity pass on to contractors without substantial and cost prohibitive premiums. This caused owners to proceed with alternative forms of contract sharing risk, where possible, and retaining them where they couldn't be passed on.[352]

Manitoba Hydro claimed to have contacted 21 major international contractors and given them an opportunity to indicate their preference as to the contract model before it decided to tender the GCC as a cost reimbursable-target price contract instead of as a fixed or unit price contract.[353] MGF testified that it had never seen that done before.[354] MGF's view was that it was Manitoba Hydro's schedule-driven contracting strategy that led to the use of a cost reimbursable pricing mechanism for the Keeyask GCC.[355]

While Manitoba Hydro cited LNG projects underway across Canada in 2012 as a reason for its decision to tender the GCC as a cost reimbursable-target price contract, the Commission is not aware of any LNG project that has been constructed in Canada since 2009 until very recently.[356] The Commission also notes that if contractors were given an opportunity to express a preference for one form of contract over another, it is hardly surprising that they would have preferred a contract structure that saw Manitoba Hydro bear most of the risks. That does not necessarily mean Manitoba Hydro would have been unable to find one or more qualified contractors willing to bid on a fixed or unit price contract.

A representative of MGF testified during the 2017/18 GRA that the Keeyask GCC could have been structured with a hybrid payment structure (cost reimbursable for below-ground work and fixed or unit price for above-ground work), and that such a hybrid structure is regularly used for major hydro-generation station construction.[357] Under such a structure, Manitoba Hydro would have borne the risk of underground geotechnical issues – which MGF testified the owner generally does if there is not a full geotechnical study (as was the case with Keeyask[358]) – while the contractor would have borne at least some of the risk for above-ground issues (e.g., for productivity).

352 2017/18 GRA, Transcript, p. 5558 [Appendix A, Tab 24].
353 2017/18 GRA, Transcript, p. 7440 [Appendix A, Tab 129]; PUB Order No. 59/18, p. 81 [Appendix A, Tab 34]; 2017/18 GRA, Exhibit MH-117, pp. 9-10 [Appendix A, Tab 130]. 2017/18 GRA, PUB Minimum Filing Requirement (MFR) 136, p. 37 [Appendix A, Tab 131].
354 2017/18 GRA, Transcript, pp. 7441, 7442 [Appendix A, Tab 129].
355 2017/18 GRA, Exhibit MGF-2, p. 161 [Appendix A, Tab 126].
356 See, for example, Natural Resources Canada, "Canadian LNG Projects" [Appendix A, Tab 132].
357 2017/18 GRA, Transcript, pp. 7436-7437, 7439 [Appendix A, Tab 129].
358 Based on a review of the 2017/18 transcripts, it appears that a full or more comprehensive geotechnical study was not done before GCC contract was awarded and construction began because the Nelson River was still running and, therefore, Manitoba Hydro was not in a position to understand the geotechnical issues under the river: 2017/18 GRA, Transcript, p. 7433 [Appendix A, Tab 129].

In its report, MGF found that with the GCC adopting a full cost reimbursable contract, Manitoba Hydro had not mitigated the commercial risk associated with Keeyask and instead was "taking all the risk on Productivity, Schedule and Cost."[359]

In its report during the 2017/18 GRA, Klohn Crippen Berger ("**KCB**") noted that it had never seen a large civil works contract (like the GCC) structured as a cost reimbursable contract. KCB criticized the lack of linkage between payment and unit prices/work completed, which it characterized as a "critical omission" because the contractor may have little incentive to actually perform the work.[360] KCB also predicated that the contractor would not be able to do the work for the original bid price.[361]

MGF found that Manitoba Hydro may not have fully understood the risks it bore under the GCC and how to set up the contract to manage and mitigate such risks.[362] MGF observed that the MHEB approved the GCC "at a price not to exceed [redacted] billion excluding taxes and escalation"[363] and noted the following regarding Manitoba Hydro's recommendation to the MHEB to approve the GCC:

- Manitoba Hydro referenced that Bechtel (a member of the **BBE** joint venture) "is an experienced contractor and was involved in the construction of the civil works for the Limestone Generating Station," despite the fact that Limestone was completed 22 years earlier and was only remotely relevant if the same construction management and supervision team was to be used on Keeyask;
- MGF was also advised by Manitoba Hydro that Bechtel was a self-performing contractor on Limestone, and this predicated Manitoba Hydro's decision to appoint BBE;
- Manitoba Hydro stated BBE was "the lowest cost and offer[ed] the best value to the project," which was not strictly correct as BBE did not offer the "cost," but rather an "Initial Target Price" (which did not necessarily reflect the actual cost to Manitoba Hydro); and
- Manitoba Hydro identified the risk of concrete productivity – stating "[c]oncrete productivity assumptions are the primary difference between [BBE's] price and the price of the other proponents" – with no further commentary on why this primary difference was not a high risk in the recommendation to award to BBE, which was of concern to MGF.[364]

Based on the foregoing, MGF concluded as follows regarding Manitoba Hydro's understanding of the risks it was assuming in the GCC:

> The above raises concerns on whether the risks inherent in the contracting strategy, e.g. a cost reimbursable compensation mechanism and potentially too aggressive concreting productivity factors were fully understood by Manitoba Hydro and how it would set up the contract to manage and mitigate such risks with their chosen contractor.[365]

The Commission was not surprised that the mention of the Limestone project as a previous engagement of Bechtel seems to have helped "carry the day" for the awarding of the GCC to BBE (which includes Bechtel). The Commission heard during several interviews (often unbidden) as to how exemplary the Limestone project was – from planning to construction and commissioning. The Commission also reviewed *Hansard* in which then-Premier Selinger defended Manitoba Hydro's PDP (including Keeyask) in part by citing the success of Limestone, as follows:

359 2017/18 GRA, Exhibit MGF-2, p. 80 [Appendix A, Tab 126].
360 2017/18 GRA, Exhibit MGF-2, Appendix A, pp. 34-35 [Appendix A, Tab 126]; 2017/18 GRA, Transcript, p. 7240 [Appendix A, Tab 129]
361 2017/18 GRA, Exhibit MGF-2, Appendix A, p. 32 [Appendix A, Tab 126].
362 The successful bidder and general contractor of the Keeyask project is a consortium of Bechtel Canada Co ("**Bechtel**")., Barnard Construction of Canada Ltd., and EllisDon Civil Ltd. (collectively, "**BBE**").
363 2017/18 GRA, Exhibit MGF-2, p. 62 [Appendix A, Tab 126]. Minutes of MHEB Meeting, February 26, 2014.
364 2017/18 GRA, Exhibit MGF-2, pp. 62-63 [Appendix A, Tab 126]. 2017/18 GRA, PUB Minimum Filing Requirement (MFR) 136, pp. 52-53 [Appendix A, Tab 131].
365 2017/18 GRA, Exhibit MGF-2, pp. 62-63 [Appendix A, Tab 126].

> **Hon. Greg Selinger (Premier):** Mr. Speaker, the experience of the opposition never changes when it comes to Manitoba Hydro. They always are looking for a reason to not build it, to mothball it. And as a result of that, we lost a decade in the '90s.
>
> They criticized Limestone as a project that was uneconomic. It was built and it paid itself back within 10 years, and then that power was available, having been paid off by export revenues available to Manitobans. The capital was paid off by the export revenues to Manitobans.
>
> The Leader of the Official Opposition needs to understand that export revenues keep rates lower in Manitoba than they would be if we did not have export revenues. The absence of export revenues would make prices rise higher in Manitoba, as we're seeing in other jurisdictions across the country.[366]

Finding #4.9: Based on MGF's report submitted during the 2017/18 GRA, the decision of Manitoba Hydro to award the GCC to BBE appears to have been motivated, at least in part, by selection bias resulting from the results of the Limestone project (on which Bechtel was engaged) 22 years earlier, which had little or no relevance to the Keeyask tender.

Finding #4.10: Manitoba Hydro's recommendation to the MHEB to approve the GCC indicates a potential lack of understanding or omission as to the full risk implications of the recommended GCC.

Recommendation #4.5: The MHEB and Minister Responsible for Manitoba Hydro must have a complete understanding of the kind of contract being recommended by Manitoba Hydro management as to cost overrun risk exposure. This understanding could come from enhanced reporting to the MHEB and the Minister and from a formal management structure to oversee any future major capital project (similar to what was put in place for Conawapa in the 1990s), which is addressed in Recommendation #2.10.

The PUB concluded that a unit price contract would have been more appropriate for Keeyask, for the following reasons:

> The evidence of Manitoba Hydro, MGF, and KCB was to the effect that in the planning for Keeyask and the preparation of the contract tendering documents, Manitoba Hydro was able to determine with remarkably high precision the quantities of concrete and earthworks (i.e. dams and dykes) that needed to be supplied and constructed. With hindsight, a unit price contract would have been more appropriate as it would have shifted the risk of labour productivity to the contractor while Manitoba Hydro retained the quantity risk.[367]

The Commission heard from a former member of Manitoba Hydro's management team that the GCC was crafted so that a private sector contractor would benefit if risks did not materialize, which would reduce the cost of the contract.[368] However, Manitoba Hydro has acknowledged that, if it were to do the Keeyask GCC all over again, "it would take a hard look at the marketplace and decide whether a cost reimbursable-target price contract was the appropriate pricing structure for the GCC,"[369] as opposed to a fixed or unit price contract.

366 Manitoba, Legislative Assembly, *Hansard*, 40th Leg., 2nd Sess., Vol. 65, No. 10 (December 3, 2012) [Appendix A, Tab 7].
367 PUB Order No. 59/18, p. 85 [Appendix A, Tab 34].
368 Information received from participant, March 25, 2020.
369 PUB Order No. 59/18, p. 82 [Appendix A, Tab 34].

Finding #4.11: Manitoba Hydro did not broadly market-test the GCC in the usual sense of the term. Meeting with several contractors and asking their preference as to the type of contract, as Manitoba Hydro did with the Keeyask GCC, is not a normal practice. Manitoba Hydro should have taken a harder look at the marketplace and more carefully considered whether a cost reimbursable-target price contract structure was appropriate and brought in external expertise for a contract of this size.

Finding #4.12: While it is understandable that Manitoba Hydro proceeded with a cost reimbursable payment structure for below-ground work, given the lack of ability to perform a full geotechnical study, it should have used a fixed or unit price structure for above-ground work in order to allocate some of the risk to the contractor. The Commissioner understands that this sort of hybrid structure is regularly used for major hydro-generation stations, whereas a full cost reimbursable contract (like the GCC) is not.

Recommendation #4.6: Manitoba Hydro should use the services of an external consultant for any future major capital projects to help with market-testing high value contracts such as the GCC and to help determine and design the appropriate contract structure, in order to minimize the risks allocated to Manitoba Hydro (and, by extension, its ratepayers) under those contracts.

Pain/gain formula and productivity levels: The GCC included a pain/gain formula intended to motivate the contractor to perform, as their profit is tied to the target price and is at risk. However, once their profit is eroded (from the project cost exceeding the target) all costs are paid by Manitoba Hydro.[370] At that point, the pain-gain formula ceases to be an effective motivator for the contractor to perform.

Manitoba Hydro described the productivity bid of BBE as a "red flag" as it was higher than Manitoba Hydro had achieved on Wuskwatim. As a result, Manitoba Hydro further investigated BBE's bid and its productivity forecast, but ultimately accepted it. A labour reserve was included in the cost estimate, in part because of concern over the productivity in the BBE bid.[371] However, Manitoba Hydro acknowledged that the labour reserve was not adequate for this purpose.[372]

The PUB concluded that these aspects of the GCC were not effectively considered by Manitoba Hydro and caused Keeyask cost overruns, as follows:

> The Board concurs with MGF and KCB that the primary root cause of the cost overrun of the GCC, and the whole Keeyask project, relates to the nature of the cost reimbursable payment structure in the GCC. Manitoba Hydro appears to have assumed that tying the contractor's profit to the target price, with the possibility that the profit could erode to zero, would provide sufficient motivation to the contractor to meet the productivity levels in its GCC bid. It further appears that Manitoba Hydro never contemplated that the contractor's profit could erode to zero so early in the project. However, underpinning the reason for the profit eroding to zero so early in the project was the fact that BBE bid productivity levels that proved to be unachievable. While Manitoba Hydro performed an evaluation of the productivity levels bid by BBE, the Utility accepted the bid, which was ultimately unachievable and formed the basis for an unrealistic target price. Once the profit eroded to zero, with no chance of re-establishing profit, the contractor had little or zero motivation to advance the project expediently. This was a principal failing of the original GCC.[373]

370 2017/18 GRA, Transcript, p. 5560 [Appendix A, Tab 24]. If the project cost is under the target, the contractor shares a portion of the savings and receives their pre-determined profit and overhead set out in the GCC. If, however, the project cost is over the target, the contractor loses a proportional amount of their profit margin and overhead: 2017/18 GRA, MH-120, p. 35 [Appendix A, Tab 133].

371 PUB Order No. 59/18, pp. 74-75 [Appendix A, Tab 34].

372 2017/18 GRA, Transcript, p. 5677 [Appendix A, Tab 24].

373 PUB Order No. 59/18, pp. 84-85 [Appendix A, Tab 34].

Finding #4.13: The primary causes of cost overruns on Keeyask were below-target labour productivity and geotechnical issues with the riverbed. The GCC allocated these and other risks (and the costs of their materialization) to Manitoba Hydro while allocating few to the general civil contractor, which introduced significant unpredictability to the outcome of the GCC. Further, the design of the GCC, combined with the fact that Manitoba Hydro accepted a bid with unrealistic productivity levels, resulted in the prime contractor having less incentive to advance the project expediently or cost-effectively. While Manitoba Hydro appears to have identified the productivity levels in the contractor's bid as a concern, it nevertheless accepted the bid and did not adequately protect against the risk of these productivity levels being unachievable (including through the labour reserve).

Recommendation #4.7: Manitoba Hydro should structure its construction contracts for major projects in a manner that incentivizes the contractor to complete the project on time and on budget. Such incentives may be achieved through a fixed or unit price contract. If Manitoba Hydro elects to proceed with a cost reimbursable-target price contract, Manitoba Hydro should ensure that it carefully reviews all bids to ensure that the contract is designed to provide meaningful and effective incentives to the selected contractor.

Recommendation #4.8: The contract type for a high-value contract such as the GCC should be part of the mandatory public review process in respect of a major capital project that is contemplated in Bill 35, given that it is an important part of the risk management process. As part of that process, Manitoba Hydro should be required to justify a choice of contract type (which should be chosen with the advice of an external consultant, as discussed in Recommendation #4.6). If Manitoba Hydro decides to use a contract type for a major capital project that is not industry standard, such as the GCC, it should be required to justify that decision during public review and seek direction before executing the contract.

Bipole III Construction Contracts

With respect to Bipole III, MGF found that Manitoba Hydro's contracting strategies were commercially astute, allocating risk appropriately between the parties and using predominantly fixed or unit pricing mechanisms which placed the risks of productivity, cost, and schedule on its contractors.[374] Unlike the case of Keeyask, the risk of cost increases for Bipole III did not materialize in a significant way. It entered service on July 4, 2018 at a capital cost of $4.77 billion, which was $270 million lower than the $5.04 billion projected in 2016.[375]

The Commission heard from a representative of Manitoba Hydro that it has strong expertise and internal capacity for transmission that is solicited around the world, and that contracting and procurement was done separately for transmission and generation.[376] This assessment of internal capacity within transmission appears consistent with MGF's report, which observed a lack of expertise with respect to some aspects of Manitoba Hydro's operations, but not with respect to transmission.[377]

Finding #4.14: Manitoba Hydro's allocation of risks with respect to Bipole III appears to have been reasonable. This can be explained, at least in part, by the internal capacity and expertise in transmission that was available for the project.

374 2017/18 GRA, Exhibit MGF-2, p. 2 [Appendix A, Tab 126].
375 PUB Order No. 69/19, p. 9 [Appendix A, Tab 82].
376 Information received from participant, January 15, 2019.
377 PUB Order No. 59/18, p. 85 [Appendix A, Tab 34].

Government Processes

The Commission is not aware of any planning or approval process undertaken by the former Government that evaluated the commercial risk associated with Keeyask or Bipole III, let alone the two together. The Commission did not learn of any such processes during interviews with former Government representatives, nor during the review of the voluminous materials requested from the Government (including a request for documents relevant to any such process).

The lack of agendas, minutes or briefing material associated with the Priorities and Planning Committee is troubling because it was a central oversight structure at the time. While the Commission received a few of these documents in response to its request for same (which demonstrate that committee meetings occurred), Keeyask and Bipole III are mentioned very little and other records of the Priorities and Planning Committee could not be found.

Finding #4.15: There appears to have been little oversight on the part of the shareholder (the former Government) as to the commercial risk associated with Keeyask and Bipole III. There is no evidence that the Minister, Cabinet or Premier played an active or even passive role in the evaluation of risk associated with these projects or its allocation. For example, there is no evidence that any information related to the risk management reports prepared by Manitoba Hydro was provided to, or requested by, the Minister or Cabinet. Nor was there any evidence of consideration of these matters in Treasury Board Secretariat minutes, apart from funding for the UNESCO World Heritage Site designation and benefits for Indigenous groups.

Finding #4.16: There was no structured regular reporting by Manitoba Hydro's CEO and/or the Chair of the MHEB to the Minister. Indeed, the Commissioner was told emphatically by a former minister that this level of regular engagement was not the role of a minister with respect to a Crown corporation. Given the massive scale and the inherent risk of Keeyask and Bipole III to Manitoba Hydro's customers and to Manitoba residents that must live with the implications thereof, it would seem important for the elected officials of the day to meet regularly with the CEO/Chair. They did not. This suggests a failure in responsible stewardship and political oversight in the interests of Manitobans.

Recommendation #4.9: Government should play an active role in evaluating commercial risk associated with major capital projects undertaken by Manitoba Hydro. This is necessary in respect of a utility which, by virtue of being government-owned, has no other shareholders to whom it is responsible and by whom it is held accountable for its performance.

Crown corporations are very much like line departments when it comes to the principle of responsible government in a parliamentary democracy. Ministers and premiers must be held accountable for Crown corporation decisions. Accordingly, there must be regular reporting and communication from the Crown corporation to the Minister, as discussed further in Recommendation #5.8. This does not necessarily imply inappropriate interference as the Crown corporation seeks to pursue its legislated mandate on commercial terms. Rather, the accountability of the Crown corporation that comes from a regular reporting relationship can act as a safeguard for the shareholder from the kinds of things that occurred with respect to Manitoba Hydro in the matters of Keeyask and Bipole III. The Crown corporation must be accountable to the Minister who, along with rest of Cabinet is, in turn, accountable to the Legislature and the public.

FISCAL IMPLICATIONS OF THE PROJECTS

Government Processes

A former government staff member noted that prior to the change in government in 2016, the Treasury Board Secretariat had very limited involvement in Crown corporations. The same individual confirmed that Treasury Board did not discuss individual projects at Manitoba Hydro during their tenure.[378]

A former government staff person reported that it was not the role of the former Government's Cabinet subcommittees to review Manitoba Hydro's capital expenditures. They further noted that these expenditures were approved by the MHEB and provided to Cabinet committees as updates.[379]

In its report, BCG cited "systemic decision governance issues," including a lack of "clear objective function and criteria/constraints" among Manitoba Hydro, the PUB, and the Province, as a factor that needs to be addressed.[380]

Finding #4.17: Based on the materials that the Commission received from the Government (including Cabinet documents), there is no evidence of the former Government having formal internal processes for reviewing the financial implications of either Bipole III or Keeyask.

Finding #4.18: In the Commissioner's view, there is a need for clarification as to the respective functions, roles, and responsibilities of Manitoba Hydro and the Government as they relate to reviewing fiscal implications for major projects like Keeyask or Bipole III. The Commissioner was troubled to hear that the Treasury Board Secretariat at the time had very limited involvement in major projects at Manitoba Hydro or Crown corporations generally, especially given the Secretariat's concern about summary net debt. The Commissioner was also troubled to hear that the former Government's Cabinet subcommittees did not review Manitoba Hydro's capital expenditures and were merely provided updates. The Commissioner is encouraged to hear that Cabinet and the Treasury Board Secretariat appear to have become more involved in Manitoba Hydro's financial affairs under the current Government. This finding is addressed by Recommendation #1.2.

Recommendation #4.10: As discussed in Chapters 2 and 3 of this report, the Government should revise Manitoba Hydro's statutory mandate as set out in *The Manitoba Hydro Act* to make it clear that Manitoba Hydro's mandate is to meet Manitoba's peak domestic load in the most cost-effective manner possible and not to maximize jobs in the north or carry out the Province's environmental policy, unless otherwise directed by the Government through a transparent process. It should not preclude Manitoba Hydro from exporting power provided it is done in accordance with provincial energy policy which, as recommended in this report, should provide guidance regarding exports including commercial targets for projects built for exports (regardless of whether they eventually are used to serve domestic demand).

Financial Implications of Bipole III Routing

The Commission heard from a former elected official that no information about the cost difference of Bipole III East and Bipole III West was provided to the former Government by Manitoba Hydro, at least as of the time that the former Government mandated a route other than the east side of Lake Winnipeg. This former elected official acknowledged that Bipole III West would have been more

378 Information received from participant, March 10, 2020.
379 Information received from participant, March 24, 2020.
380 BCG, "Review of Bipole III, Keeyask and Tie-Line Project," September 19, 2016, p. 5 [Appendix A, Tab 22].

expensive because of its greater length, but also implied that there would be costs of longer delays associated with obtaining necessary permits on the east side (because of Indigenous opposition, among other reasons).[381]

The Commission heard a different recollection from a former Manitoba Hydro executive, who noted that the cost of routing Bipole III on the west side of the Province was presented to the Government of the day.[382] The former executive noted that the Government's response to the cost information was that they could route Bipole III any way other than down the east side of Lake Winnipeg.

Cost estimates for the various routes were included in documents provided by the Government to the Commission. According to the document with cost estimates for Bipole III West and Bipole III East that was closest in date to when the former Government mandated a route other than the eastern route (September 2007), Bipole III West was expected to cost $500 million more than the eastern route and would require $1.2 billion in converters to be advanced.[383] It is not clear what level of scrutiny these cost estimates received or what government approval process considered this cost information (if any).

In *Hansard* from September 2007, Hugh McFayden, then Leader of the Official Opposition, referenced the same cost differential for Bipole III East and Bipole III West ($500 million more for the latter) and cited a statement by Manitoba Hydro's CEO at the time, Bob Brennan, in support of the differential. In response, then Premier Gary Doer admitted that Bipole III East would have been cheaper to build given its shorter distance, as follows:

> We fully admitted that the cost of doing the west side transmission line was higher from a straight, straight-line basis. It's obviously cheaper to build a straight line than it is to have a more circuitous route. We admitted that during the campaign.[384]

In December 2007, Bob Brennan, then CEO of Manitoba Hydro, testified before the Standing Committee on Crown corporations that Bipole III West would take two years longer to complete than Bipole III East: one year because of more consultation required and another year because of the greater distance.[385]

In an op-ed in the Winnipeg Free Press in April 2008, Greg Selinger, then Minister Responsible for Manitoba Hydro, noted that the cost of Bipole III East was $1.8 billion, compared to $2.2 billion for Bipole III West based on information provided by Manitoba Hydro. Then leader of the Progressive Conservative opposition, Hugh McFadyen countered with his own article in the same paper later that month, noting that the cost quoted by Greg Selinger for Bipole III East was inflated by $1.1 billion due to the inclusion of a converter station that was not needed, making the extra cost of Bipole III West $1.5 billion, not the $400 million noted by Selinger.[386]

381 Information received from participant, July 15, 2020.
382 Information received from participant, February 26, 2020.
383 Briefing Note, Department of Finance, "Bipole III - Routing Options," November 23, 2005.
384 Manitoba, Legislative Assembly, *Hansard*, 39th Leg., 1st Sess., Vol. 59, No. 10 (September 26, 2007) [Appendix A, Tab 6].
385 Manitoba, Legislative Assembly, Standing Committee on Crown Corporations, *Debates*, 39th Leg., 2nd Sess., Vol. 60, No. 4 (December 19, 2007) [Appendix A, Tab 134].
386 Brandon Sun, "Why the west side is the best side," April 9, 2008 [Appendix A, Tab 135]; Brandon Sun, "West side is wrong, but you don't have to take my word for it," April 12, 2008 [Appendix A, Tab 136].

Finding #4.19: The Commission heard conflicting statements about the availability of information from Manitoba Hydro to the former Government regarding the comparative costs of Bipole III East and Bipole III West. The Commission also reviewed conflicting information about the comparative costs of these routes, including those resulting from delays. However, based on the information reviewed and outlined above, it appears that, at the time the former Government mandated a route other than Bipole III East, Bipole III East would have been at least $400 million to $500 million less expensive to build than Bipole III West, largely based on its shorter distance. Any costs associated with delay likely cannot be quantified in hindsight, given the passage of time (among other reasons).

A review of *Hansard* indicates a lack of concern for Bipole III routing costs on the part of the former Government. In May 2009, concerns were raised in the Legislature regarding the soundness of the costs of building Bipole III on the west side of the Province. Greg Selinger (then Minister Responsible for Manitoba Hydro) responded by generally discussing the need for stimulus and employment in the economy which, at the time, was in the midst of a global recession.[387] This response ignored the fact that Bipole III could have been built less expensively on the east side of Lake Winnipeg while also bringing employment and stimulus to that part of the Province, where it was greatly needed.

Later that year, concerns were again raised in the Legislature regarding the cost of Bipole III West particularly to individual Manitobans. At that time, Rosann Wowchuk (the Minister Responsible for Manitoba Hydro) responded that Bipole III East would be much more expensive and would "put at risk $20-billion worth of [export] sales."[388] This claim that Bipole III East would be more expensive than Bipole III West is contrary to all of the documents reviewed by the Commission.

This $20 billion export sales figure cited by former Minister Wowchuk increased in subsequent years. In 2010, Minister Wowchuk stated that with Bipole III and new generation stations operational, revenues from hydro exports were projected to exceed $20 to $22 billion over the next two decades.[389] In 2013, Dave Chomiak (then Energy Minister) stated that Keeyask and Conawapa would "pay for themselves" because of $7 billion in firm export contracts and "another $20 billion" that were being negotiated.[390] Mr. Chomiak also stated that year that export contracts were "projected to generate $29 billion in export revenue over the next 30 years."[391]

Finding #4.20: The evidence available to the Commission suggests that the former Government gave little consideration to the cost differences between Bipole III West and Bipole III East. As discussed in Chapter 1 of this report, Bipole III East was rejected by the former Government because of its concerns with U.S.-based opposition to the route, a UNESCO World Heritage Site designation, opposition by some east side First Nations, and effects on export opportunities (which could not be substantiated), after which time the only option that was seriously considered by Manitoba Hydro was Bipole III West. This concern is addressed by Recommendation #1.2.

387 Manitoba, Legislative Assembly, *Hansard*, 39th Leg., 3rd Sess., Vol. 61, No. 38B (May 7, 2009), p. 1790 [Appendix A, Tab 137].
388 Manitoba, Legislative Assembly, *Hansard*, 39th Leg., 4th Sess., Vol. 62, No. 12 (December 15, 2009), p. 361 [Appendix A, Tab 138].
389 Brandon Sun, "Bipole III route best for Hydro's future," August 13, 2010 [Appendix A, Tab 139]; Brandon Sun, "Project must proceed," February 1, 2010 [Appendix A, Tab 140]; Brandon Sun, "McFadyen misses mark with Hydro comments" September 23, 2010 [Appendix A, Tab 141].
390 Winnipeg Free Press, "Hydro, gas hikes get go-ahead," April 27, 2013 [Appendix A, Tab 142].
391 Brandon Sun, "Halting hydro projects puts long-term prosperity at risk," February 12, 2013 [Appendix A, Tab 143].

Finding #4.21: As found in Chapter 3 of this report, Manitoba Hydro's (and the former Government's) export forecasts were overly optimistic given the inherent risks and uncertainties underlying Manitoba Hydro's assumptions about carbon "premiums" and demand for hydro-electric power in the U.S. export market, and the competition that Manitoba Hydro will face in the export market. At the start of the NFAT, Manitoba Hydro estimated export revenues from firm contracts of $9 billion, which fell to $6.9 billion during the NFAT and even lower afterwards with the cancellation of its largest contract, the WPS 308 MW sale (as discussed in Chapter 3 of this report).

Manitoba Hydro Internal Processes

Manitoba Hydro's IFFs speak of financial implications of its major projects along with other estimates and assumptions about the future that are subject to change. The IFFs show an evolving forecast of impacts on borrowing, as well as some passing references to impacts on rates, but the issue is reported as an outcome of Manitoba Hydro's development plan as opposed to an important implication to be considered in determining the appropriateness of that development plan relative to alternatives.

Manitoba Hydro's November 2008 IFF08-1 included a PUB-approved 5% electricity rate increase in 2008 and 4% (conditional) increase in 2009, followed by annual increases of 2.9% per year starting in 2010. It was forecasted that Manitoba Hydro would achieve its target debt/equity ratio (75/25) by the end of 2008/09 and maintain it until 2014/15, "when capital expenditure levels begin to grow as a result of the construction of Keeyask, Conawapa and Bipole III."[392] Manitoba Hydro's 20-Year Financial Outlook released shortly thereafter projected that Manitoba Hydro would again achieve its target-debt equity ratio (after capital expenditures associated with major projects) by 2024.[393] Drought was noted as a major risk in both documents, and interest rates and foreign exchange, export prices, domestic load growth, and increased capital costs were also noted in IFF08-1. Citing IFF08-1 and its proposed rate increases, one former Manitoba Hydro executive concluded and advised the MHEB that it would be possible for Manitoba Hydro to build Keeyask and Bipole III (among other planned projects) without undue negative impacts on financial ratios.[394] This advice was based on extra-provincial revenue estimates and project capital cost estimates at the time, which proved too high in the case of the former and too low in the case of the latter. The presentation with this advice was received as information during a meeting of the MHEB.[395]

In its report, BCG noted that the decision to build Keeyask was imprudent "due to a failure to fully assess the risks" including:

- Financial modelling that did not fully reflect the specific project risks (e.g., construction execution, market prices, domestic demand);
- Discount rates that favoured high capital projects over lower upfront cost projects; and
- The magnitude of the overall level of debt that both Manitoba Hydro and the Province of Manitoba would ultimately be exposed to, especially given the concurrent build of Bipole III.[396]

The BCG report further noted that risks such as these have "adversely impacted the economics of the projects and continued to put Hydro into a more and more difficult financial position, making construction of Keeyask and the tie-line in particular an even more questionable decision."[397]

392 Manitoba Hydro, Integrated Financial Forecast (IFF08-1), November 2008, p. 15 [Appendix A, Tab 144].
393 2010/11 GRA, Appendix 16, p. 6, Figure 3 [Appendix A, Tab 145].
394 Vince Warden, Vice-President, Finance & Administration and Chief Financial Officer, Manitoba Hydro, "20 Year Financial Forecast," August 14, 2008.
395 Minutes of MHEB Meeting, August 20, 2008.
396 BCG, "Review of Bipole III, Keeyask and Tie-Line Project," September 19, 2016, p. 2 [Appendix A, Tab 22].
397 BCG, "Review of Bipole III, Keeyask and Tie-Line Project," September 19, 2016, p. 3 [Appendix A, Tab 22].

Sanford Riley, then Chair of the MHEB, accepted BCG's findings in September 2016 but concluded that the projects were too far along to cancel.[398]

Finding #4.22: As BCG's review made clear and the MHEB accepted, the decision to build Keeyask was imprudent due to a failure to fully assess the risks, including its fiscal implications and the level of debt that both Manitoba Hydro and the Province would ultimately be exposed to, especially given the concurrent build of Bipole III. The degree of risk was attendant on export market forecasts (which, as discussed in Chapter 3, were overly optimistic) and executing Keeyask and Bipole III on budget, which did not happen.

Recommendation #4.11: The decision to build a project of the scale and cost of Keeyask should not be made until after the risks have been fully assessed, including the project's immediate and long-term fiscal implications for Manitoba Hydro (and its ratepayers) and the Province (and its taxpayers). As recommended in Chapter 1 of this report, the need for a project should be justified through comprehensive IRP completed by Manitoba Hydro and then reviewed by an independent regulator such as the PUB in a public proceeding.

Under Bill 35, the required NFAT of a major new facility should also include a full assessment of risk and fiscal implications.

One former executive of Manitoba Hydro suggested that Manitoba Hydro should develop an internal finance area that more rigorously evaluates capital expenditures and project justifications. The former executive stated that major projects were a historic issue for the company and recommended that the internal finance area should have staff with wide-ranging expertise to determine the best ways to proceed with these projects based on financial implications. They noted that, in the case of Keeyask, a dichotomy developed whereby engineers at Manitoba Hydro were generally in favour of the project whereas those in finance advised against it.[399]

In its response to MGF's report, Manitoba Hydro noted that in 2016 it established the MPEC comprising Manitoba Hydro's President and CEO as well as five vice- presidents with accountability over the areas of the company responsible for the execution of major capital projects. The MPEC was established to provide oversight, direction, and strategic decision making with respect to Keeyask, Bipole III, the Manitoba Minnesota Transmission Project ("**MMTP**"), and the **Great Northern Transmission Line** project in Minnesota.[400]

Finding #4.23: Based on the decision to proceed with Keeyask despite the concerns of Hydro's finance staff, it appears that Manitoba Hydro's internal processes and decision-making structures placed a greater emphasis on the input of the engineers over other disciplines such as finance.

Recommendation #4.12: As discussed in Chapter 5, the Commissioner views Manitoba Hydro's establishment of the MPEC as a good decision and a positive development in terms of project oversight, coordination, and accountability within Manitoba Hydro. The MPEC or a structure with similar, direct executive involvement (including the President and CEO) should be in place at the beginning of any future large-scale capital project at Manitoba Hydro. Such a structure helps provide clear lines of responsibility and executive oversight within the company.

398 Winnipeg Free Press, "Hydro board slams handling of Bipole III, Keeyask dam projects – but says it's too late," September 21, 2016 [Appendix A, Tab 146].
399 Information received from participant, February 18, 2020.
400 2017/18 GRA, Exhibit MH-117, p. 13 [Appendix A, Tab 130].

PUB Processes

Financial Targets

Incorporating the capital costs of Keeyask and Bipole III (as forecasted at the time), financial modeling during the NFAT considered what the rate trajectories of different development plans would have to be to reach Manitoba Hydro's 75/25 debt/equity target in 18 years (i.e., by 2031/32, the same timeline in the aforementioned 2015 Corporate Risk Management Report).[401] This was done using Manitoba Hydro's 20-year IFF as well as longer-term rate trajectories.[402] In the case of Plan 6 (Keeyask and the 750 MW interconnection, the development plan that is currently proceeding), equal annual rate increases of 3.75% were projected until 2031/32 achieve the target. In its report, the NFAT Panel recommended relaxing the debt/equity target to mitigate such rate increases.[403]

During the 2017/18 GRA, Manitoba Hydro requested 7.9% rate increases to achieve a 75/25 debt/equity level in 10 years (i.e., by 2026/27, not by 2031/32 as in the NFAT). Instead, the PUB approved a 3.36% interim rate increase and a 3.6% rate increase in 2018,[404] based on a consideration of the interests of Manitoba Hydro's ratepayers and the financial health of Manitoba Hydro (as required by the PUB's mandate).[405] This most closely approximated a rate scenario of annual 3.57% rate increases to achieve the target debt/equity ratio by 2035/36.[406]

During the 2019/20 electric rate application, Manitoba Hydro requested a 3.5% interim rate increase to avoid a projected net loss of $28 million from electrical operations in 2019/20. While Manitoba Hydro did not update its long-term financial forecast, it noted that, even if the requested 3.5% rate increase in 2019/20 was granted, its cumulative earnings from 2017/18 to 2019/20 would be almost $200 million less than it assumed during the 2017/18 GRA. It further noted that those lower-than-expected financial results would exacerbate the longer-term losses projected during the 2017/18 GRA.[407] The fact that the requested 3.5% increase was not granted (a 2.5% increase was granted instead, with all revenues therefrom to be placed in a deferral account for major capital projects under construction)[408] would have only further exacerbated those projected losses. Absent consistently higher rate increases than the 3.57% annual increase projected during the 2017/18 GRA, those increased losses over the longer term would lead to a later recovery to the targeted 25% equity ratio than was projected during the 2017/18 GRA (i.e., later than 2035/36).[409]

In its report to the PUB as part of the review of Manitoba Hydro Financial Targets and the 2017/18 GRA, MPA concluded that the debt/equity ratio should not be the primary financial target that is taken into

401 NFAT Report, p. 169 [Appendix A, Tab 15]; NFAT, Exhibit MH-111, p. 36 [Appendix A, Tab 147].
402 NFAT Report, p. 168 [Appendix A, Tab 15].
403 NFAT Report, p. 191 [Appendix A, Tab 15].
404 PUB Order No. 59/18, p. 266 [Appendix A, Tab 34].
405 PUB Order No. 59/18, p. 43 [Appendix A, Tab 34].
406 2017/18 GRA, Exhibit MH-93, p. 4 [Appendix A, Tab 148]; PUB Order No. 59/18, p. 173 [Appendix A, Tab 34].
407 2019/20 Electric Rate Application, pp. 2, 4 [Appendix A, Tab 149].
408 PUB Order No. 69/19, p. 3 [Appendix A, Tab 82].
409 2019/20 Electric Rate Application, pp. 2, 4 [Appendix A, Tab 149].

account when setting rates for the future, largely on the basis that it is not the focus of capital market observers:

> This emphasis on capital structure is not shared by capital market observers, who instead are more focused on measures of cash flow sufficiency to meet debt obligations, in keeping with their primary interest of protecting their debt investments. While capital structure is an important consideration, it is nevertheless secondary in credit analysis, and only indirectly sheds light on financial risk. This suggests that if preventing negative impacts on the credit rating of the Province of Manitoba is a concern, then pursuing a Debt : Equity ratio is a secondary way of doing so. Instead, a more direct focus on ensuring cash flow sufficiency through rate-setting would be more likely to provide that support. However, lest the importance of stability and predictability be forgotten, the need to ensure the support of the capital markets for Manitoba Hydro should be balanced against the need to avoid wildly swinging rates. Cash flow sufficiency need not be an annual condition, but can rather be ensured on a rolling forward basis, which will help to manage both the predictability of rates, and the sufficiency of cash flows.[410]

MPA also described issues with debt/equity targets in terms of rate stability and predictability and changing variables:

> However, if it is determined that Debt : Equity Ratio should be a primary focus, then the question arises whether the goal of meeting the target in 2027 is appropriate.
>
> A glaring issue with this goal, even in a scenario where all reference assumptions were to prove miraculously accurate, is that in the year following the achievement of the target a very significant rate decrease would be warranted, otherwise the target would be substantially exceeded in short order. This casts into doubt the value of this timing goal from the perspective of rate stability and predictability, and also from the perspective of cash flow stability and predictability.
>
> Manitoba Hydro stated in the risk assessment included in the original application that a 7.9% rate path would have a 50% probability of achieving the Debt target by 2027, in the face of a variety of uncertain variables… No clarity was provided about which variables would be allowed to undermine the reaching of that goal, and how they would relate to rate-making. For example, interest rates have already risen somewhat, presumably reducing the probability of reaching the goal: what should be the rate response, if any? A fixed target for a specific date, which does not take into account changing variables and contexts, and is not adjustable and related to real drivers of rate-making policy, does not appear credible.[411]

MPA further questioned the prioritization of "equity" in financial targets for Manitoba Hydro, as follows:

> As a pure cost recovery, government-owned utility, it is not clear why "equity" should be a priority per se. From the perspective of the ratepayers who are the ultimate funders of all of the utility's operations, "equity" is essentially "dead money": it earns no return, but nevertheless has been taken out of the hands of the ratepayers who could otherwise use it. A review of rate paths through the lens of discounting at the social discount rate helps to stress the importance of making use of ratepayer funds in the most economical way.[412]

410 2017/18 GRA, Exhibit CC-17, p. 55 [Appendix A, Tab 150].
411 2017/18 GRA, Exhibit CC-17, p. 56 [Appendix A, Tab 150].
412 2017/18 GRA, Exhibit CC-17, p. 55 [Appendix A, Tab 150].

KPMG LLP ("**KPMG**") was retained by the MHEB to undertake a review of Manitoba Hydro's current financial targets prior to the 2017/18 GRA. KPMG recommended that the primary measure of Manitoba Hydro's financial position should remain the debt/equity ratio. Specifically, it recommended Manitoba Hydro should maintain a long-term debt/equity target in the range of 75/25 to 70/30 with a minimum of 85/15 during major capital programs, for the following reasons:

> Manitoba Hydro's current debt/equity target of 75/25 is a reasonable long term target. Notwithstanding this finding, we note that a target of 70/30 would provide additional financial strength to address the utility's unique financial challenges and risks…
>
> Manitoba Hydro will need to depart from its equity target during major build programs: this reflects the utility's limited financing tools and reliance on retained earnings as its dominant source of equity. Accordingly, the equity position should rise above 25% in advance of major build programs to mitigate the deviations from target that are observed.
>
> We have significant concerns that an 11% equity level, as forecast under IFF14, provides a less than desirable equity base to accommodate potential adverse developments. We suggest that Manitoba Hydro's plans be adjusted to maintain an equity ratio no lower than 15% under forecast conditions during the peak periods of its major capital build program when equity ratios are at their lowest levels.
>
> In the long term, with respect to deviations from any target, it would be desirable to limit decreases in the equity ratio to 5-10 percentage points.
>
> In the long term, higher equity ratios need not translate into higher rates, because Manitoba Hydro has the option to seek lower rates of return on equity than investor-owned utilities.[413]

KPMG also recommended that Manitoba Hydro should maintain a minimum EBITDA interest coverage ratio target of 1.8 or greater and a minimum capital coverage ratio target of 1.2 or greater. Regarding the former, KPMG stated:

> An interest coverage ratio is an important element of financial targets and indicator of trends. EBITDA is a widely accepted financial measure and is closer to a cash flow metric than EBIT, albeit with limitations since it does not incorporate capital expenditure requirements or working capital adjustments.[414]

Regarding the minimum capital coverage ratio target of 1.2 or greater, KPMG stated:

> The capital coverage ratio is also an important financial target and a unique measure to Manitoba Hydro.
>
> The current minimum target of 1.2 or greater is reasonable in that the corporation should be able to fund its sustaining base capital from current operations without accessing external sources of financing. However, an inherent limitation of this ratio is that it does not reflect the financial challenges associated with major expansion programs. Hence it may be misunderstood or misinterpreted by stakeholders.[415]

As part of its review, KPMG compared average residential prices of electricity to those in cities in other provinces and nearby states, which showed that Manitoba had the second lowest prices in the country

413 2017/18 GRA, Appendix 4.5, pp. 7-8 [Appendix A, Tab 151].
414 2017/18 GRA, Appendix 4.5, p. 8 [Appendix A, Tab 151].
415 2017/18 GRA, Appendix 4.5, p. 8 [Appendix A, Tab 151].

for residential consumers (next to Quebec). The average price for residential customers in Winnipeg was 9.75 cents per kWh, compared to an average of 14.1 cents per kWh among the 12 Canadian cities that were compared.[416]

KPMG also compared the financial targets/plans of Government-owned power utilities in Canada, including Manitoba Hydro which showed that, like Manitoba Hydro, the following utilities also have a debt/equity target:

- BC Hydro (65/35);
- Hydro-Quebec (75/25);
- Nalcor [Newfoundland/Labrador] (70/30); and
- NB Power (70/30).

KPMG noted that the only other public power utility with an EBITDA interest coverage ratio target is Nalcor, whose target is 1.5 or greater (compared to Manitoba Hydro's target of 1.8 or greater), and that no other public utility has a minimum capital coverage ratio target.[417]

A former Manitoba Hydro executive told the Commission that, rather than a debt/equity ratio, a more apt financial target could be determined by identifying and quantifying the risks that Manitoba Hydro faces and the equity that Manitoba Hydro needs to meet them. Then other measures regarding cash flow (e.g., EBITDA) would follow, which would measure the cash flow that assets are generating for Manitoba Hydro. The former executive expressed the belief that while a debt/equity target is convenient to explain to credit agencies and the PUB how Manitoba Hydro will build up equity and to show progress, such a target as a standalone target (i.e., independent of an assessment and quantification of risks) is the wrong approach.[418]

The PUB has also recently questioned the debt/equity metric and accepted MPA's evidence, as follows:

> The Board accepts Morrison Park Advisors' evidence that debt-to-equity is a questionable metric for a vertically integrated monopoly Crown utility with a debt guarantee from the provincial government. The equity level target does not have the prominence suggested by Manitoba Hydro given the context in which the Utility operates. The concern regarding the value of the equity level target is compounded when Manitoba Hydro is going through an unprecedented major investment period to more than double the value of its assets in the next four years. As noted by Manitoba Hydro's external consultant KPMG, there is a "practical recognition that this target will not be met during a period of large capital expenditures when newly constructed assets are placed in service. Accordingly, the 75/25 could remain the long term objective." The Board supports this view…. As such, the Board is not prepared to look at the issue of pacing to achieve a particular equity level target at least until the current phase of major capital construction is completed, now projected by Manitoba Hydro to be in 2024.[419]

The Commission is aware of cases in which the Province of Manitoba has experienced credit downgrades from two rating agencies, both of whom have tied the finances of Manitoba Hydro to the

416 2017/18 GRA, Appendix 4.5, p. 41 [Appendix A, Tab 151].
417 2017/18 GRA, Appendix 4.5, p. 48 [Appendix A, Tab 151].
418 Information received from participant, February 13, 2020.
419 PUB Order No. 59/18, pp. 63-64 [Appendix A, Tab 34], as cited in PUB Order No. 69/19, p. 28 [Appendix A, Tab 82].

Province's rating. In the case of its July 2017 downgrade of the Province's rating (from "AA-" to "A+"), Standard and Poor's noted the following in its ratings report about Manitoba Hydro:

> Our assessment of the province's debt burden fully incorporates the debt on-lent to MHEB, which accounts for more than 40% of total tax-supported debt and for which the province expects to borrow heavily to finance capital projects over the next several years. We do not view MHEB as self supporting due to its very high and rising leverage.[420]

Moody's downgraded the Province's rating in August 2014 and, in a subsequent report, noted the following concern about Manitoba Hydro's finances:

> The province issues debt on behalf of its wholly-owned electric utility company Manitoba Hydro. Given its steady revenue stream that generates sufficient cash flow to support operations including interest payments, we view Manitoba Hydro as a self-supporting entity and therefore exclude the related debt from our debt metrics of the province.
>
> We note, however, that Manitoba Hydro's total reported debt net of sinking of funds has risen considerably, doubling from CAD6.9 billion at March 31, 2008 to an estimated CAD14.2 billion as of March 31, 2016. We expect that its debt will continue to rise over the medium-term as the utility moves forward with construction projects, including the Keeyask hydroelectric station and the Bipole III transmission line, in anticipation of demand increases over the next few years and in order to boost electricity exports. The anticipated increase in debt continues to pressure the province's rating since it raises the contingent liability of the province.[421]

Finding #4.24: The Commissioner notes that other government-owned power utilities in Canada continue to use debt/equity targets which are not materially different from Manitoba Hydro's current 75/25 target. In the Commissioner's view, a long-term debt/equity target has value by helping prevent negative impacts on the Province's credit rating, particularly during adverse developments like the COVID-19 pandemic. However, achievement of a debt/equity target should not be the singular focus and an interest coverage ratio target should also be used. The Commissioner recognizes that in the short-term, aggressive debt/equity targets can have a negative impact on rate stability and predictability and, therefore, cash flow stability and predictability. The Commissioner further recognizes that financial targets must take into account changing variables and context and be adjustable based on real drivers of rate-making policy, including risks.

Government Transfers

In the NFAT, the PUB considered returns to the Government from Keeyask in the form of debt guarantee fees, capital taxes, and water rentals.[422] Evidence regarding transfers to the Province from Bipole III and Keeyask was also before the PUB in the 2017/18 GRA.[423]

The evidence in those proceedings was that no matter how the projects turned out financially, the Province would receive annual transfers from Manitoba Hydro in the form of debt guarantee fees, capital taxes, and (in the case of Keeyask) water rentals. These amounts of these transfers were estimated to be up to:

- $143 million annually (declining over time) related to Keeyask; and
- $74 million annually (declining over time) related to Bipole III.[424]

420 2017/18 GRA, Appendix 4.5, p. 53 [Appendix A, Tab 151].
421 2017/18 GRA, Appendix 4.5, pp. 54-55 [Appendix A, Tab 151].
422 See, for example, NFAT Report, p. 225 [Appendix A, Tab 15].
423 2017/18 GRA, Information Request (IR) PUB/MH I-21 [Appendix A, Tab 152].
424 2017/18 GRA, Information Request (IR) PUB/MH I-21 [Appendix A, Tab 152].

There was also evidence that transfers to the Province increase as the costs of the projects increase, based on the debt guarantee fees.[425]

During the 2017/18 GRA, the PUB summarized the evidence before it regarding transfers to the Government from Bipole III and Keeyask as follows:

> Even though Bipole III is not yet in service, in fiscal year 2018, Manitoba Hydro will pay $43 million to the Province for the debt guarantee fee and an additional $22 million to the Province for capital tax. Each of those amounts will increase when Bipole III is fully in-service in fiscal 2019. Likewise, even though Keeyask's in-service date has been delayed 21 months, in fiscal year 2018, Manitoba Hydro will pay $44 million to the Province for the debt guarantee fee and an additional $22 million for capital tax. No water rental fees for Keeyask will be paid to the Province until that generating station enters service when those water rental fees will reach $18 million per year in 2025.
>
> When those two major capital projects are completed and beginning in 2023, Manitoba Hydro estimates it will pay approximately $490 million to the Province each year. The amount paid to the Province will decrease once Manitoba Hydro is repaying debt, thereby reducing its debt guarantee fees.[426]

The Manitoba Industrial Power Users Group provided a comparison of payments to government by Manitoba Hydro and other Canadian Crown-owned electric utilities showing that in 2018/19 (i.e., before the maximum amount of payments from Keeyask and Bipole III is reached) Manitoba Hydro's total payments to government as a percentage of gross revenue are second only to Hydro-Quebec, which is set out in the chart below.[427]

Payments to Government ($ Millions)						
($ Millions)	Manitoba Hydro (Forecast 2018/19)	British Columbia Hydro (Forecast 2018/19)	Hydro-Quebec (2016 Actual, forecast not available)	Newfoundland Labrador Hydro (Forecast 2018/19)	SaskPower (Forecast 2018/19)	New Brunswick Power (Forecast 2018/19)
Water Rentals	103	350.1	667	0	21	0
Debt Guarantee Fee	185	0	218	2.2	0	31.8
Capital & Other Taxes	145	238.7	284	0	50	45.1
Other	0	0	0	0	35	0
Payments to Gov't	**433**	**588.8**	**1,169**	**2.2**	**106**	**76.9**
Gross Operations Revenue	2,246	4,836.8	13,339	696.5	2,697.6	1,705.5
Payments to Gov't as Percentage of Gross Revenue	***19.3%***	***12.2%***	***8.8%***	***0.3%***	***3.9%***	***4.5%***
Dividends	0	70.8	2,146	0	21	0
Total Payments to Gov't (with dividend)	**433**	**659.6**	**3,315**	**127**	**76.9**	**76.9**
Total Payments to Gov't (with dividend) as Percentage of Gross Revenue	*19.3%*	*13.6%*	*24.9%*	*0.3%*	*4.7%*	*4.5%*

The PUB found that as a percentage of gross operations revenue, Manitoba Hydro's payments to the Province are high, both before and after considering jurisdictions where dividends are paid by Crown-owned electric utilities. The evidence demonstrated that, excluding payments made to municipal governments, approximately 17 to 18 cents of each dollar of gross revenue is directed by Manitoba Hydro to the Province.[428]

425 PUB Order No. 59/18, p. 176 [Appendix A, Tab 34].
426 PUB Order No. 59/18, p. 176 [Appendix A, Tab 34].
427 2017/18 GRA, Exhibit MIPUG-30, p. 3 [Appendix A, Tab 153], as cited in PUB Order No. 59/18, p. 178 [Appendix A, Tab 34].
428 PUB Order No. 59/18, p. 180 [Appendix A, Tab 34].

Finding #4.25: The evidence from the NFAT and 2017/18 GRA about transfers from Manitoba Hydro to the Government – particularly their quantum relative to most other provinces and how they are protected if projects do not turn out well financially (and may increase) – is important for the purposes of Recommendations #1.6 and #2.6 regarding how Government should bear the risk of export projects underperforming, rather than ratepayers.

CHAPTER 5

Post-Approval Oversight

> *"The impression left with the former executive was that the former Government wanted Manitoba Hydro to spend money to build Keeyask and Bipole III, but did not want it to raise rates to pay for them."*

INTRODUCTION

In accordance with section 5 of the Terms of Reference, the Commission inquired into the extent to which the oversight process that was followed after Keeyask and Bipole III were approved:

(i) reflected best practices then applicable for such projects; and

(ii) mitigated the associated commercial risk and accommodated changing circumstances as they occurred.

This chapter presents the Commissioner's findings and recommendations from this inquiry.

For the purposes of addressing this section of the Terms of Reference, the Commission considers Keeyask and Bipole III to have been (formally) approved as of the date that the respective licences were issued for them under *The Environment Act*. Under *The Environment Act*, neither Bipole III nor Keeyask could legally have been built or operated until Manitoba Hydro obtained a licence to do so.[429] In the case of Bipole III, this licence was issued on August 14, 2013.[430] For Keeyask, the licence was issued on July 10, 2014.[431]

POST-APPROVAL PROJECT OVERSIGHT

Keeyask

Manitoba Hydro's Oversight of BBE

Based on Manitoba Hydro's previous experience with the Wuskwatim project, it identified risks and mitigation actions for Keeyask, including project management requirements.[432] It noted that it had incorporated lessons learned from Wuskwatim (and Pointe du Bois) into the delivery of Keeyask, and that its project management capabilities had been built up over a 10-year period in preparation for delivering Keeyask and Bipole III.[433]

429 Bipole III was classified as a Class 3 development, the construction and operation of which required a licence from the Minister under section 12(1) of *The Environment Act*. Keeyask was considered as a Class 2 development, the construction and operation of which required a licence from the director under section 11(1) of *The Environment Act*.

430 *The Environment Act* Licence No. 3055, August 14, 2013 [Appendix A, Tab 154].

431 *The Environment Act* Licence No. 3106, July 10, 2014 [Appendix A, Tab 155].

432 NFAT, Transcript, pp. 85, 115 [Appendix A, Tab 85].

433 2017/18 GRA, Transcript, pp. 5551-5552 [Appendix A, Tab 24].

During the 2017/18 GRA, Manitoba Hydro identified the following lessons learned from past projects that were relevant to Keeyask (and Bipole III):

> Lessons learned from past projects include: Early contractor involvement is valuable. The contract model has to fit the circumstances and market conditions. Goals and incentives must be mutual and tied to project critical success factors. Independent third-party reviews are beneficial, providing independent perspective on the projects and processes enhances the opportunity for continuous improvement. Rigorous oversight is essential. Project integration is critical to success. Manitoba Hydro has to be active in managing the interface points between contracted work packages, and doing things as they have always been done does not work for complex projects that require constant innovation and a culture of collaboration.[434]

In commentary regarding the contract model of the Keeyask GCC, KPMG characterized Manitoba Hydro's role as Project and Site Construction Manager, which it explained as follows:

> As Project Manager, MH is responsible to ensure integration, alignment and quality of the project as a whole. As Site Construction Manager, MH is responsible for the overall coordination and oversight of site work, while delegating the construction planning, management of labour and construction means and methods (along with other responsibilities) to the contractor.

During the 2017/18 GRA, MGF was retained by the PUB as an independent expert consultant to review Manitoba Hydro's capital expenditure program, which included Keeyask and Bipole III. In its report submitted to the PUB, MGF found that the Keeyask GCC was not properly managed by Manitoba Hydro considering the cost reimbursable nature of the contract (the use of which by Manitoba Hydro is discussed in Chapter 4 of this report). MGF stated:[435]

> Manitoba Hydro staff are competent and professional but they are not a construction manager with the experience and skills to direct the GCC. As such, its project management and control effectiveness is low.[436]

Regarding the cost reimbursable nature of the Keeyask GCC, MGF noted that in traditional fixed contracts "time is the contractor's money," whereas in cost reimbursable contracts (like the GCC) "time is the owner's money" (i.e., Manitoba Hydro's money and, by extension, ratepayers' money). It further noted that a cost reimbursable contract "promotes and rewards inefficient work and doesn't encourage efficient work."[437] Accordingly, MGF stated that Manitoba Hydro needed to "have a more hands on approach" in order to reduce cost and schedule overruns.[438]

Another independent expert consultant, KCB, assisted MGF in reviewing the contracting methodology for Keeyask and whether the contract format was reasonable and appropriate. As stated in Chapter 4, KCB noted that it had never seen a large civil works contract (like the GCC) structured as a cost reimbursable contract. KCB criticized the lack of linkage between payment and unit prices/work completed, which it characterized as a "critical omission" because the contractor may have little incentive to perform the work. KCB further noted that Manitoba Hydro "is not a contractor and likely does not have the staff and experience to direct all aspects of a major project like Keeyask day to day, in sufficient detail."[439]

434 2017/18 GRA, Transcript, pp. 5551-5552 [Appendix A, Tab 24].
435 2017/18 GRA, Exhibit MH-117, Appendix A, pp. 3-4 [Appendix A, Tab 130].
436 2017/18 GRA, Exhibit MGF-2, p. 1 [Appendix A, Tab 126].
437 2017/18 GRA, Exhibit MGF-2, p. 80 [Appendix A, Tab 126].
438 2017/18 GRA, Exhibit MGF-2, p. 81 [Appendix A, Tab 126].
439 2017/18 GRA MGF-2, Appendix A, pp. 34-35 [Appendix A, Tab 126].

In its report, MGF identified things that Manitoba Hydro could do to enforce compliance with the GCC, and effect change in the performance of the general contractor, BBE. These included:

- periodic contract management audits to ensure Manitoba Hydro and their contractors were complying with their respective contracts;[440]
- hiring experienced site supervisors with trade backgrounds to implement a more efficient workplan;[441]
- guiding and instructing the contractor on more efficient crew make-ups, work methods, shift lengths, and supervision;[442] and
- being proactive in the construction management of the GCC.[443]

In its response to MGF's report, Manitoba Hydro stated that it had been pushing, and would continue to aggressively push, BBE to perform, which would require that it and BBE work together.[444] Some of the examples that it cited were:

- BBE's management of the trades;
- BBE's revised organizational structure and increased supervision capacity and experience;
- the development of an effective monitoring and control system to provide daily feedback to contractor workforce;
- combining and streamlining BBE's and Manitoba Hydro's quality control and assurance teams and processes; and
- establishing a single mission and team ethics for Manitoba Hydro and BBE teams.[445]

Manitoba Hydro recognized that the decision to manage the project using an internal team brought certain risks. To reduce those risks, it stated that it retained external expertise and reviews were completed in certain areas. These included a health check by KPMG in 2016, the 2016 report by BCG discussed throughout this report (and later in this chapter), a "cold eyes" review by Hatch (the project design engineer for Keeyask), and assistance from Validation Estimating to develop the project control budget.[446]

In its 2017/18 GRA decision, the PUB found that if a cost reimbursable pricing structure is used, effective oversight of the contractor must be exercised, as explained by MGF.[447] It stated that the "results for Keeyask indicate there was not effective oversight under the cost reimbursable contract arrangement."[448] The PUB concluded that, had Manitoba Hydro exercised more effective oversight of BBE from the beginning, cost overruns (discussed in the next section of this chapter and in Chapter 4) may have been mitigated. It agreed with MGF's observation that Manitoba Hydro is not a construction manager and that it appeared that Manitoba Hydro did not have the necessary expertise or awareness of how to manage a cost reimbursable contract.[449]

With respect to cost control, a 2012 Stantec report commissioned by Manitoba Hydro found that cost management was not sufficiently addressed in the procedures of Manitoba Hydro's New Generation Construction Division, particularly considering the scope of the major projects then being considered

440 2017/18 GRA, Exhibit MGF-2, p. 54 [Appendix A, Tab 126].
441 2017/18 GRA, Exhibit MGF-2, p. 81 [Appendix A, Tab 126].
442 2017/18 GRA, Exhibit MGF-2, p. 81 [Appendix A, Tab 126].
443 2017/18 GRA, Exhibit MGF-2, p. 162 [Appendix A, Tab 126].
444 2017/18 GRA, Exhibit MH-117, p. 14 [Appendix A, Tab 130].
445 2017/18 GRA, Exhibit MH-117, pp. 22-23 [Appendix A, Tab 130].
446 2017/18 GRA, Exhibit MH-117, pp. 24-25 [Appendix A, Tab 130].
447 PUB Order No. 59/18, pp. 35, 255-256 [Appendix A, Tab 34].
448 PUB Order No. 59/18, p. 35 [Appendix A, Tab 34].
449 PUB Order No. 59/18, p. 85 [Appendix A, Tab 34].

(Keeyask and Conawapa). Stantec noted that there should be a strong culture of cost tracking throughout the project, including during the execution phase.[450] In the health check in 2016, KPMG similarly found that cost control procedures were not sufficiently robust and should be improved.[451] This suggests that Stantec's recommendation was not addressed between 2012 and 2016.

Finding #5.1: Manitoba Hydro did not appear to learn lessons from Wuskwatim, or at least it did not incorporate those lessons learned as it claimed. As discussed in Chapter 4 of this report, the contract model (cost reimbursable target price) did not fit the circumstances for the Keeyask project and should not have been used and there were inadequate incentives for the general contractor to perform efficiently – both contrary to the lessons that Manitoba Hydro said it learned from Wuskwatim. Furthermore, as discussed in this chapter, greater third-party review was needed, and Manitoba Hydro should have exercised more rigorous oversight and been more active in managing the work – all in accordance with the lessons that Manitoba Hydro said it learned from Wuskwatim. The reality that Keeyask experienced significant cost overruns just like Wuskwatim undermines the claim that lessons were learned and applied.

Finding #5.2: The Commissioner agrees with the PUB that the results for Keeyask in 2016 and 2017 indicate that there was not effective oversight under the cost reimbursable GCC by Manitoba Hydro. If more effective oversight of BBE had been exercised by Manitoba Hydro, project cost overruns may have been mitigated.

Finding #5.3: Manitoba Hydro did not have the necessary internal expertise to manage the GCC to avoid cost and schedule overruns. Manitoba Hydro itself stated that the decision to manage the project using an internal team brought risks and that to reduce those risks it retained external expertise. However, it did not retain any independent experts to reduce those risks until 2016 and they did not report to Manitoba Hydro until those risks had already begun to materialize. Manitoba Hydro also failed to heed the advice from Stantec in 2012 regarding cost control.

In Order No. 59/18, the PUB recommended that Manitoba Hydro use the services of an external construction management expert for future capital projects (particularly for high value projects and those with cost reimbursable payment structures), from the initial study and planning through to project execution. In its view, such a construction management expert would be able to assist Manitoba Hydro with effective project controls, enforcement of the contract terms, and identification of recourse in the event of contractor non-performance[452] – issues that Manitoba Hydro faced on Keeyask.

The Commission similarly heard from a former manager that Manitoba Hydro's internal processes could be improved with more use of external consultants.[453]

The PUB noted in its 2017/18 GRA order that MGF and KCB made useful recommendations that Manitoba Hydro should consider implementing, and partially had implemented. It directed Manitoba Hydro to report to it, at the next GRA, the extent to which it has implemented these recommendations and the results.[454]

450 Stantec, "Manitoba Hydro – New Generation Construction Division, Review of Program & Project Management Best Practices," 2012, pp. 12-13.
451 KPMG LLP, "Manitoba Hydro – Keeyask Generating Station – Capital Project Healthcheck, Cost and Schedule Assessment," July 2016, p. 31.
452 PUB Order No. 59/18, p. 255 [Appendix A, Tab 34].
453 Information received from participant, February 26, 2020.
454 PUB Order No. 59/18, p. 84 [Appendix A, Tab 34].

Recommendation #5.1: The Commissioner concurs with the recommendation that Manitoba Hydro use the services of an external construction management expert for future high-value capital projects and those with cost reimbursable payment structures, who could help Manitoba Hydro with effective cost controls and risk management.

The Commissioner also concurs that Manitoba Hydro should continue implementing recommendations made by MGF and KCB. Manitoba Hydro should also report on its implementation of recommendations in the Keeyask health check that KPMG prepared in 2016 regarding cost control, forecasting, and risk management, and it should report its progress on implementing MGF, KCB, and these KPMG recommendations, both to the PUB at the next GRA and to the Government.

Recommendation #5.2: For any future major capital project that Manitoba Hydro proposes to construct, it should be required to demonstrate available capacity for project management through internal and/or external resources. This is a matter of execution risk that must be dealt with and considered during the mandatory public review of the project. This review should focus on the specific individuals and processes proposed to be used for the project in question, not Manitoba Hydro's institutional expertise that the project team may or may not benefit from. For areas where Manitoba Hydro lacks internal expertise, it should retain the services of external parties through a model that shares risks for that aspect of project execution with the third party (such as a P3 model, as discussed in Recommendation #2.2).

As discussed in Chapter 4 of this report, Manitoba Hydro and the former Government placed a lot of weight on the success of the Limestone project when it came to justifying decisions with respect to the construction of Keeyask, including awarding the GCC to BBE. The Commission heard during interviews with current and former representatives from Manitoba Hydro (often unbidden) as to how exemplary the Limestone project was from planning to construction, as managed by Manitoba Hydro. It was suggested that Limestone and its success is the norm of what can be expected from projects built by Manitoba Hydro, as opposed to the cost overruns of the Wuskwatim and Keeyask projects.[455]

However, the Limestone project had a unique genesis that often seems to be forgotten. In the Limestone experience there was no added cost for transmission. The federal government had partnered with Manitoba in the 1960s to construct the infrastructure required to develop hydroelectric generation on the Nelson River in support of a national power grid then promoted by the federal government.[456] Under agreement, the federal government loaned the funds to construct the Bipole system and deferred any payments until the load growth was sufficient to carry the financial burden of the line.[457] A federal loan under such favourable terms made the Limestone project significantly less risky than the codependent Keeyask and Bipole III projects. The payment deferral protected Manitoba Hydro from liquidity risk and removed a significant portion of overall project risk from the Limestone project.

The stoppage of the Limestone project for an eight-year period also had another significant, albeit unforeseen, benefit. When the project began its preliminary construction in the mid-1970s under an NDP government, Manitoba Hydro had estimated the project cost to be $3 billion to build. A new Conservative government in the Province halted the project in 1977. By the time an NDP government returned to power and restarted the project in 1985, new bids reduced its cost to $2 billion.[458] This 33% reduction had an unexpected, positive benefit on the economics of the project and with strengthening U.S. export opportunities and prices following the eight-year project delay, the project was economically successful after it was commissioned.

455 Information received from participant, March 10, 2020; Information received from participant, January 16, 2019.
456 Karl Froschauer, *White Gold – Hydroelectric Power in Canada* (UBC Press, 1999), p. 138.
457 Leonard Bateman, "A History of Electric Power Development in Manitoba," IEEE Canadian Review, Winter 2005, p. 24 [Appendix A, Tab 156].
458 Macleans, "The Shaping of Limestone," August 11, 1986, p. 34 [Appendix A, Tab 157].

Limestone, a project that required only generation investment and that benefitted from reduced costs and increased export opportunities and prices following an eight-year delay, cannot fairly be used as a measure of the success that can normally be expected from projects built by Manitoba Hydro.

What one can say is that some projects work out and timing is very important to the outcome.

Finding #5.4: Manitoba Hydro placed too much weight on the Limestone project from decades past rather than the more recent Wuskwatim project, which was much less successful. This unjustified selectiveness reflects a bias at Manitoba Hydro towards it building new projects, regardless of the outcomes that can realistically be expected.

Recommendation #5.3: Given the PUB's jurisdiction to consider Manitoba Hydro's capital expenditures as a factor in setting rates and to ensure that rates reflect prudent expenditures, the PUB should carefully scrutinize the costs incurred by Manitoba Hydro with respect to capital projects like Keeyask. Any costs incurred by Manitoba Hydro that are not prudent should be excluded in the PUB's calculation of rates and thus borne by Manitoba Hydro and its shareholder (the Government of Manitoba), rather than ratepayers. This would provide an incentive to Manitoba Hydro and the Government of Manitoba to provide greater oversight of any future major capital projects and implement processes to mitigate cost overruns and avoid incurring imprudent costs.

Manitoba Hydro reported on its implementation of MGF's recommendations during the 2019/20 Electric Rate Application. It stated that it had implemented certain recommendations and was in the process of considering implementing others. It further stated the following:

> In January 2018, during the 2017/18 & 2018/19 GRA, Manitoba Hydro laid out its approach on the closer collaboration between Manitoba Hydro and the GCC to improve performance and achieve the plan for the 2018 construction season and ultimately deliver the project within the revised control budget of $8.7B and related schedule. The intended approach aligned with the closer collaboration on execution planning and oversight of the GCC recommended by MGF as well as working with the GCC to develop an achievable plan in 2018 based on production experienced to date. Manitoba Hydro has increased the pressure on the GCC to perform, and has collaborated wherever possible to stimulate greater productivity.[459]

As noted in the next section in this chapter, these steps by Manitoba Hydro helped realize improved productivity for Keeyask starting in 2018.

Finding #5.5: The results for Keeyask in 2018 indicate improved oversight by Manitoba Hydro that has mitigated further project cost overruns and delays.

Manitoba Hydro's Management of Multiple Projects Concurrently

Manitoba Hydro faced significant demands and risks related to managing multiple large projects at the same time, including Keeyask, Bipole III, the MMTP, and a major infrastructure refurbishment program. These risks included impacts on the execution of projects and on the financial health of Manitoba Hydro, both of which materialized.

459 2019/20 Electric Rate Application, p. 32 [Appendix A, Tab 149].

The Commission heard from a representative of Manitoba Hydro that having two "mega" projects (i.e., Keeyask and Bipole III) under one roof was not tenable and that they do not know anyone who could do that. This representative said that it was overwhelming and there could have been better oversight if only one of the projects had been underway at a time.[460]

The Commission also heard from former Manitoba Hydro executives that by the time Keeyask and Bipole III were approved, their experienced "project guys" had retired,[461] that nobody in the Generation unit of Manitoba Hydro had ever done a major project before, and that people on the project were from southern Manitoba, not the north.[462]

Finding #5.6: Capacity was stretched within Manitoba Hydro because it was managing multiple large projects. Although capacity appears to have existed for Bipole III (which was well managed, as found below in this chapter and elsewhere in the Report), internal capacity appears to have been lacking with respect to the management of Keeyask, particularly given the poor results in 2016 and 2017. This was likely due, at least in part, to the amount of time that had passed since Manitoba Hydro's last major generation project, given that Wuskwatim was a relatively small station with 210 MW of capacity and much smaller than Keeyask. Manitoba Hydro did not seem to recognize this lack of internal expertise or, if it did, it failed to address it soon enough through the use of external consultants.

Recommendation #5.4: To supplement Recommendations #5.1 and #5.2 for Manitoba to use external expertise for any future high-value capital projects (including potential P3 arrangements), Manitoba Hydro should plan its capital development program where possible so that multiple "mega" projects are not constructed simultaneously. This would help avoid capacity issues and improve project execution, which would, in turn, improve the financial health of Manitoba Hydro (and the Province). To the extent that any major projects are carried out by Manitoba Hydro in the future, dedicated senior management should be assigned to provide clear lines of responsibility and executive oversight, as noted in Recommendation #4.12.

Manitoba Hydro's Internal Project Oversight

In its response to MGF's report, Manitoba Hydro noted that in 2016 it established the MPEC, comprising Manitoba Hydro's president and CEO as well as five vice-presidents with accountability over the areas of the company responsible for the execution of major capital projects. The MPEC was established to provide oversight, direction, and strategic decision making with respect to Keeyask, Bipole III, MMTP, and the Great Northern Transmission Line project in Minnesota.[463]

Prior to the establishment of the MPEC, the Commission understands that there was a Major Capital Projects Business Unit with dedicated senior management for major projects. The Major Capital Projects Business Unit's purpose was to deliver major projects and had a dedicated vice-president and staff who had functions specific to a project (i.e., Bipole III or Keeyask). In 2016, the Major Capital Projects Business Unit was dissolved and executive responsibility for Bipole III and Keeyask returned to the vice-presidents of Transmission and Generation, respectively.[464]

460 Information received from participant, February 12, 2020.
461 Information received from participant, January 15, 2019.
462 Information received from participant, January 16, 2019.
463 2017/18 GRA, Exhibit MH-117, p. 13 [Appendix A, Tab 130].
464 Information received from participant, January 15, 2019.

Finding #5.7: The Commissioner views the establishment of the MPEC as a good decision and a positive development in terms of project oversight, coordination, and accountability within Manitoba Hydro. This structure appears to have been effective in terms of recovery on Keeyask and avoiding further delays and cost overruns. The Commissioner would expect a similar structure to be in place for any future large-scale capital projects at Manitoba Hydro. The Commissioner's recommendations for Manitoba Hydro's reporting structure are further addressed in Recommendations #2.10 and #4.5.

Manitoba Hydro also described the Keeyask project governance structure, as follows:

> As Keeyask Project is owned by the KHLP, there are additional accountabilities beyond the Manitoba Hydro organization structure. The Keeyask Project team is also accountable to the KHLP Board that is comprised of representatives from each of the four Keeyask Cree Nation ("KCN") Partner Communities and Manitoba Hydro. The KHLP Board is chaired by the Manitoba Hydro Vice President of Generation and Wholesale. The Keeyask Project team provides monthly update reports to the KHLP, as well as makes quarterly update presentations at the Board meetings.[465]

The Commission heard from a representative of Manitoba Hydro that project briefings were provided to the MHEB once per month, sometimes in the form of a written report. The Commission also heard that there was quarterly reporting to the PUB.[466]

The Commission understands that in 2017 a new capital approval policy was implemented at Manitoba Hydro, whereby approval from the MHEB Capital Committee is required for (a) a project with a total cost of more than $50 million, and (b) changes (addendum) for such projects where the quantum of the change is the lesser of 25% or $25 million.[467]

Finding #5.8: The Commissioner views Manitoba Hydro's new capital approval policy as a positive development, particularly given evidence that critical project-related information (at least related to performance) was not previously reflected in reports to senior management and the MHEB.

Recommendation #5.5: The MHEB must be provided with accurate, timely, and complete information on all material aspects of project development – including regarding project management risks and cost overruns – so that it can properly discharge its duties and make good decisions. It is the MHEB that is ultimately accountable (to the Government and, by extension, to Manitobans) for Manitoba Hydro's capital program and the consequences of any cost overruns or other failures. The Government relies on the MHEB for its analysis.

The Commission heard from a former member of Cabinet that there were concerns in the past regarding political interference in the internal affairs of Manitoba Hydro, including those raised by Commissioner Tritschler in his 1979 report. This former member stated that the proper place for the relationship between the Government and Manitoba Hydro is between the Chair of the MHEB and the Premier or the Minister Responsible for Manitoba Hydro, rather than some other channel. For example, this former member of Cabinet stated that a minister has no place talking to Manitoba Hydro's CEO on a regular basis.[468]

While a minister might prefer having a single point of contact within a Crown corporation such as Manitoba Hydro, the Commissioner believes that this preference is outweighed by the value of more

465 2017/18 GRA, Exhibit MH-117, p. 14 [Appendix A, Tab 130].
466 Information received from participant, January 15, 2019.
467 2017/18 GRA, Transcript, pp. 2201-2201 [Appendix A, Tab 158].
468 Information received from participant, July 15, 2020.

open exchange of information between a Crown corporation and its shareholder, the Government, which is fundamental to the proper reporting relationship and the accountability of both the Crown corporation and the Government. A relationship that is rigid to the extent of requiring reporting through the Chair of the MHEB alone, and not through the CEO of Manitoba Hydro, does not support more open exchange of information nor the greater accountability that comes from it.

Finding #5.9: During the Commission's review of documents received from Manitoba Hydro and the Government, it encountered very few written briefings from Manitoba Hydro or the MHEB to the Minister Responsible for Manitoba Hydro. The written briefings reviewed appeared to have been provided on an ad hoc basis. This raises the question of what the Government knew and when it knew it. Written briefings regarding the escalating costs for Keeyask and Bipole III in particular ought to have been provided to the Government, yet the Commission did not encounter such a document among either the Cabinet documents or briefing notes to government that were reviewed.

Recommendation #5.6: The Commissioner believes that the relationship between the Government and Manitoba Hydro should be between the Chair of the MHEB, the CEO of Manitoba Hydro and the Minister Responsible for Manitoba Hydro. There should be regular briefings from the Chair of the MHEB and the CEO of Manitoba Hydro to the Minister Responsible for Manitoba Hydro, in addition to any project-specific briefing recommended in this report. The Minister Responsible for Manitoba Hydro should, in turn, be accountable for decisions by Manitoba Hydro, including to the Legislature through plenary proceedings and standing committees.

The Commission heard from former officials at Manitoba Hydro that the MHEB could benefit from more external expertise and technical advisors before it makes decisions regarding major projects.[469] One former executive suggested increasing the qualifications of MHEB members to include at least one member with out-of-province expertise and ensuring the MHEB has commercial expertise. The same executive noted that including an MLA on the MHEB was a shortcoming in the professional governance of the MHEB.[470]

Finding #5.10: Based on the Commissioner's review of MHEB minutes, it unclear that the MHEB held Manitoba Hydro management to account as was their duty, particularly as risks materialized and costs rose.

Recommendation #5.7: The Chair of the MHEB must ensure that the MHEB has the capacity to evaluate management proposals and hold management to account, as is its duty. To the extent that the MHEB does not have this capacity through its members, the Chair of the MHEB should ensure that the MHEB retains external expertise (e.g., in the form of external reviews and technical advisors) to ensure that it is properly discharging its oversight function.

If a regular reporting relationship is in place between Manitoba Hydro and the Government, as discussed in Recommendation #5.8, there is no need to have any MLAs appointed to the MHEB.

469 Information received from participant, March 25, 2020; Information received from participant, January 15, 2019.
470 Information received from participant, January 15, 2019.

Bipole III

As previously noted in this chapter, MGF was retained during the 2017/18 GRA to review Manitoba Hydro's capital expenditure program, which also included Bipole III. MGF found that Bipole III was generally well organized and managed efficiently, allowing it to be completed within the control budget in place at the time.[471]

The PUB agreed that the Bipole III project was well organized and managed and that, as of May 1, 2018, it was only 8% over the final pre-construction budget ($4.65 billion).[472] The PUB also presumably believed that it was reasonable to expect that Bipole III would be completed within the $5.04 billion control budget, as it prescribed the control budget amount for the purposes of IFF modelling and rate setting in the 2017/18 GRA.[473]

As noted in Chapter 4 of this report, the risk of significant cost increases and delays for Bipole III did not materialize. It entered service on July 4, 2018 (27 days ahead of schedule) at a capital cost of $4.77 billion, which was $270 million lower than the $5.04 billion control budget[474] and closer to the final pre-construction estimate of $4.65 billion.

However, it should be noted that the budget achieved ($4.77 billion) was significantly higher than the $3.28 billion budget for Bipole III that was in place until August 2014 – less than four years earlier. This $3.28 billion budget had been in place since 2011,[475] including during the CEC's review of the project and the NFAT, and when a licence for Bipole III was issued under *The Environment Act*. These previous cost estimates are further discussed in Chapter 4.

Finding #5.11: Notwithstanding route change implications and cost estimation errors prior to 2014, Bipole III appears to have been well managed by Manitoba Hydro thereafter, and the results on the project (only marginally over the final pre-construction budget) indicate that there was effective oversight. MGF's independent review of Manitoba Hydro's major capital expenditures during the 2017/18 GRA confirmed as much.

RISK MITIGATION AND ACCOMMODATION OF CHANGING CIRCUMSTANCES

Keeyask

The Commission heard from a former Manitoba Hydro executive that a team within Manitoba Hydro performed a review in the winter of 2015/16 to ascertain whether there was an off-ramp or delay opportunity for Keeyask. This review appears to have been prompted by the start of a new CEO's tenure at Manitoba Hydro in December 2015 and the view that there could be a change in government direction with the spring 2016 election. The results of this review were that there was a potential off-ramp under the JKDA if concrete was not poured; however, it was determined to not be practical, as there had been significant investments made already to that point and concrete was scheduled to begin pouring in April 2016, while any decision not to pour would have delayed the

471 2017/18 GRA, Exhibit MGF-2, pp. 1-2 [Appendix A, Tab 126].
472 PUB Order No. 59/18, pp. 257, 258 [Appendix A, Tab 34].
473 PUB Order No. 59/18, p. 97 [Appendix A, Tab 34].
474 PUB Order No. 69/19, p. 9 [Appendix A, Tab 82].
475 2017/18 GRA, PUB Minimum Filing Requirement (MFR) 154 [Appendix A, Tab 32].

project and added millions of dollars in costs. Accordingly, it was determined that it was best for Manitoba Hydro to focus on completing Keeyask in the most economical way.[476]

The Commission also heard that there was no option to consider an off-ramp with Government and that the former Government would not have been receptive to any discussion of an off-ramp.[477]

Finding #5.12: There was a small, informal off-ramp in respect of Keeyask; however, there was no formal process associated with it and it was not a practical off-ramp, given the significant investment to date and government support for the project. If a hard off-ramp had been available in respect of Keeyask, it likely would have been identified in early 2016 and brought before the MHEB, although it likely would not have made any difference if the former Government would not consider the option.

By early June 2016 – approximately six weeks into concrete activities – the contractor, BBE, was already falling behind on its targets for concrete placement. Manitoba Hydro requested a recovery plan from BBE that month, but by the end of the 2016 construction season, the project was far behind schedule. Concrete placement was 41% complete for the year while earthworks were 65% complete for the year. [478]

In its September 2016 report, BCG – as part of its retainer by the MHEB – identified an anticipated increase in the Keeyask budget of $0.7 billion (from $6.5 billion to $7.2 billion) and a delay of 21 months from the loss of one complete summer season, "likely due to GCC contract underperformance, especially related to earthworks … and concrete productivity."[479] BCG identified the potential for an additional cost increase of $0.6 billion (to $7.8 billion) and a further delay of 11 months related to performance under the Keeyask GCC.[480]

Despite its finding that the original decision by the provincial Government and Manitoba Hydro to construct Keeyask (and the tie-line) was imprudent (as discussed in Chapter 4 of this report), BCG concluded in its 2016 report that the most prudent decision was to finish the work to completion, based on the current state of execution and the estimated incremental costs to cancel or delay at that point. BCG estimated that approximately $1 billion would be incurred for each of Keeyask and Bipole III if the projects were to be stopped, bringing their total costs to $7 billion.[481] It identified mitigation measures that, in its opinion, could prevent further cost overruns and delay, which included improving concrete and earthworks productivity.[482]

On September 21, 2016 – two days after the BCG report was finalized – Sanford Riley, then Chair of the MHEB, said during a news conference that Bipole III and Keeyask should not have been built, but also that they were too far along to cancel. He cited BCG's review.[483]

Manitoba Hydro initiated development of its own recovery plan strategy in September 2016 in hopes of improving productivity. This recovery plan strategy included:

- a plan for the continuation of concrete through the winter (previously not planned);
- identification of root causes of performance issues;

476 Information received from participant, February 13, 2020.
477 Information received from participant, February 13, 2020.
478 2017/18 GRA, Exhibit MH-117, p. 15 [Appendix A, Tab 130]; PUB Order No. 59/18, p. 75 [Appendix A, Tab 34].
479 BCG, "Bipole III, Keeyask and Tie-Line Review," September 19, 2016, p. 28 [Appendix A, Tab 28].
480 PUB Order No. 59/18, p. 76 [Appendix A, Tab 34].
481 BCG, "Review of Bipole III, Keeyask and Tie-Line Project," September 19, 2016, pp. 3, 7 [Appendix A, Tab 22].
482 PUB Order No. 59/18, p. 76 [Appendix A, Tab 34].
483 Winnipeg Free Press, "Hydro board slams handling of Bipole III, Keeyask dam projects – but says it's too late," September 21, 2016 [Appendix A, Tab 146].

- engagement of senior leadership, executive sponsors, and CEOs;
- development of refined processes, systems, and tools based upon the findings of the root cause analysis;
- implementation of a change management program to enable a culture shift within the project team;
- initialization of activities to reforecast the cost and schedule for the project;
- analysis of the contractor's claims; and
- supplementing the commercial expertise of the Manitoba Hydro team.[484]

Manitoba Hydro and BBE investigated the underlying causes of the lower-than-expected concrete and earthworks productivity and completion rates. The main contributing factors that they identified were:

1. unachievable productivity rates for earthworks and concrete in BBE's original bid;
2. slow ramp-up by BBE to full production in the early part of 2016; and
3. geotechnical and geological challenges.[485]

As part of its recovery plan, Manitoba Hydro leveraged support from the following external consultants:

- KPMG (recovery plan support);
- Revay (claims valuation and management);
- Borden Ladner Gervais LLP (legal support); and
- Validation Estimating (contingency development).[486]

With the support of these external consultants, Manitoba Hydro carried out a risk assessment of recovery options and determined that amending the scope of the GCC or terminating BBE were higher cost, higher risk options and that amending the existing contract with BBE was the lowest cost, lowest risk option.[487]

Based on the findings of Manitoba Hydro's risk assessment, in January 2017, Manitoba Hydro negotiated a revision to the GCC with BBE, referred to as Amending Agreement 7. According to Manitoba Hydro, in order to amend the existing contract with BBE, there were "gives and takes" and limits to how much risk could be allocated to BBE (as opposed to Manitoba Hydro).[488] KPMG described the challenges inherent in attempting to renegotiate the GCC as follows:

> The amended contract continues to be a Target Price Cost Reimbursable contract, fundamentally the same as the original contract. The ability to transfer additional risk, such as geotechnical, hydrology, labour, extreme weather, and northern logistics to BBE by changing the contract to a Unit Rate or Lump Sum contract, would have required directly negotiating a new form of contract with BBE in a non-competitive environment or descoping/terminating BBE and going back to the market for a Unit Rate contract. It was expected that in a non competitive environment and given BBE's performance in 2016, the costs of transferring this risk to BBE would have been prohibitive and/or not achievable.[489]

484 2017/18 GRA, Exhibit MH-117, p. 16 [Appendix A, Tab 130].
485 2017/18 GRA, Exhibit MH-117, pp. 16-17 [Appendix A, Tab 130].
486 2017/18 GRA, Exhibit MH-117, p. 17 [Appendix A, Tab 130].
487 2017/18 GRA, Exhibit MH-117, p. 17 [Appendix A, Tab 130]; PUB Order No. 59/18, p. 76 [Appendix A, Tab 34].
488 2017/18 GRA, Exhibit MH-117, p. 17 [Appendix A, Tab 130]; PUB Order No. 59/18, p. 77 [Appendix A, Tab 34].
489 2017/18 GRA, Exhibit MH-117, Appendix A, p. 2 [Appendix A, Tab 130].

Like the original GCC, Amending Agreement 7 had a cost reimbursable-target price payment structure. It included a new target price and an extended schedule, which reflected the overruns noted by BCG. It re-established the possibility for BBE to earn profit by setting a new target price based on revised productivity factors and an extended schedule with the first generating unit expected to enter service in August 2021.[490] In 2017 (after Amending Agreement 7 was executed), the cost estimate for Keeyask was increased from $7.2 billion (per BCG) to $8.7 billion,[491] which it has remained since.

Despite revised productivity factors (i.e., person-hours per cubic metre of concrete placed) and other changes that were made in hopes of getting the project back on budget and on schedule, BBE again fell short of end-of-year targets for concrete placement and earthworks in 2017 (by 20% and 25%, respectively).[492] Concrete and earthworks productivity improved from 2016 levels (by 12% and 15%, respectively), but not enough to meet these targets.[493]

Nonetheless, the PUB acknowledged during the 2017/18 GRA that Manitoba Hydro had taken steps to mitigate schedule issues and productivity, including through retaining external consultants, as follows:

> The Board acknowledges that Manitoba Hydro has taken steps to mitigate schedule issues and productivity, including through retaining Boston Consulting Group, KPMG, Revay, Validation Estimating, and Borden, Ladner, Gervais LLP for recommendations. There was evidence in the GRA that Manitoba Hydro has achieved milestones in the construction of Keeyask, including that the project is on track to meet the schedule for diverting the river through the spillway to permit work to be done on the south dam. The Board's expectation is that Manitoba Hydro will closely monitor and take steps to improve productivity in order to achieve the 10% improvement in productivity on all aspects of the GCC required to meet the $8.7 billion control budget.[494]

Things appear to have turned around in 2018. BBE exceeded the concrete placement target that year (with more than 20% higher productivity than 2017) and met the earthworks target (almost doubling productivity). By the end of November 2018, more than 83% of concrete had been placed and Manitoba Hydro indicated to the PUB that, although significant project risks remained, necessary improvements to achieve the $8.7 billion control budget were being realized and the in-service date was trending ahead of schedule.[495]

Manitoba Hydro attributed these performance improvements to closer collaboration with BBE, working with BBE to develop an achievable plan in 2018 based on production experienced prior to that, and increased pressure on BBE to perform.[496]

Finding #5.13: The Commissioner acknowledges that the MHEB reacted promptly and properly took steps to mitigate schedule issues and productivity in 2016 and 2017, including through retaining BCG and other external consultants for recommendations.

490 PUB Order No. 59/18, p. 77 [Appendix A, Tab 34]; 2017/18 GRA, Exhibit MH-117, p. 17 [Appendix A, Tab 130].
491 2017/18 GRA, PUB Minimum Filing Requirement (MFR) 122, p. 2 [Appendix A, Tab 159].
492 2017/18 GRA, Exhibit MH-117, p. 20 [Appendix A, Tab 130]; PUB Order No. 59/18, p. 78 [Appendix A, Tab 34].
493 2017/18 GRA, Exhibit MH-117, p. 19 [Appendix A, Tab 130].
494 PUB Order No. 59/18, pp. 83-84 [Appendix A, Tab 34].
495 2019/20 Electric Rate Application, p. 32 [Appendix A, Tab 149].
496 2019/20 Electric Rate Application, p. 32 [Appendix A, Tab 149].

Finding #5.14: After years of delays and cost overruns, Manitoba Hydro was ultimately able to work with BBE to achieve the revised productivity targets for Keeyask in 2018. This was due to a combination of increased oversight over BBE by Manitoba Hydro, Manitoba Hydro benefitting from its prior years of experience on the project (including its shortcomings), and significantly relaxed cost and schedule targets for Keeyask.

Finding #5.15: The results in 2018, while a positive development for the project, also highlight what could have been achieved previously had there been better stewardship and oversight by Manitoba Hydro.

Bipole III

As noted above, Bipole III entered service on July 4, 2018, which was 27 days ahead of schedule. Its final capital cost was $4.77 billion, which was $270 million lower than the $5.04 billion control budget[497] and close to the final pre-construction estimate of $4.65 billion.

It appears that much of this accomplishment can be attributed to Manitoba Hydro's contracting strategies for Bipole III, which predominantly used lump sum (i.e., fixed price) or unit rate pricing mechanisms (unlike the cost reimbursable Keeyask GCC). MGF concluded that these contracting strategies were "commercially astute, allocating risk appropriately between the parties … which place[d] the risks of productivity, cost and schedule on its contractors"[498] (unlike the Keeyask GCC). MGF found that the potential for a cost overrun on Bipole III was low, due to most of the remaining costs being under fixed price contracts.[499]

The completion of Bipole III ahead of schedule and under the control budget was also due (at least in part) to Manitoba Hydro's more "hands on" management of contractors on the project, which was less complicated than a major new generating station like Keeyask. As noted above, MGF's view was that the project was on schedule by the end of the 2017 construction season, although some critical path activities were slipping. In response, Manitoba Hydro de-scoped and replaced one contractor for a significant section of work, which had represented a significant risk to the project schedule. Manitoba Hydro also took legal action to recover additional costs from the replaced contractor because of its scope removal and lack of performance.[500]

Finding #5.16: Manitoba Hydro did an effective job managing Bipole III contractors to mitigate commercial risk and accommodate changing circumstances. This effective management, risk mitigation, and accommodation included terminating an underperforming contractor who was responsible for a significant section of work and taking legal action to recover additional costs from them. This contrasts with Keeyask – a more complicated project involving a major new generating station – in respect of which Manitoba Hydro was not effective in managing contractors.

Government Processes

The Commission is not aware of any post-approval oversight process undertaken by the former Government that mitigated the risks associated with Keeyask or Bipole III or that accommodated changing circumstances as they occurred. The Commission did not learn of any such processes during interviews with former Government representatives, nor during the review of the voluminous materials requested from the Government (including a request for documents relevant to any such process).

497 PUB Order No. 69/19, p. 9 [Appendix A, Tab 82].
498 2017/18 GRA, Exhibit MGF-2, p. 2 [Appendix A, Tab 126].
499 PUB Order No. 59/18, p. 91 [Appendix A, Tab 34]; 2017/18 GRA, Exhibit MGF-2, pp. 1-2 [Appendix A, Tab 126].
500 2017/18 GRA, Exhibit MH-117, p. 42 [Appendix A, Tab 130].

The Commission heard from a former Manitoba Hydro executive that there was difficulty engaging the former Government in coherent decision making and discussion regarding the Keeyask and Bipole III projects following their approval, and that there was no opening to discuss any change with respect to the projects. The former executive stated that discussions with the former Government were around rates and that they believed that the rate increase sought by Manitoba Hydro at the time was too high, whereas members of the MHEB believed that the increase sought was the minimum possible to satisfy their fiduciary obligation. The impression left with the former executive was that the former Government wanted Manitoba Hydro to spend money to build Keeyask and Bipole III, but did not want it to raise rates to pay for them.[501]

The Commission heard similar comments about the former Government's singular focus on minimizing rate increases from other former executives at Manitoba Hydro.[502] One such executive, when asked how much attention the former Government paid to Manitoba Hydro's finances, stated that rates were always the biggest concern of the former Government.[503]

Finding #5.17: The Commissioner saw no evidence of interest or proactive outreach on the part of the former elected Government of Manitoba to provide oversight, accountability, and overall leadership on the Keeyask and Bipole III projects. The former Government seems to have been largely focused on rate increase issues instead. As the costs of the projects grew and the potential impact on Manitoba Hydro became apparent, there is no evidence that the former Government engaged with the MHEB or provided any direction. While the construction of the projects was a priority and part of the former Government's vision of "Manitoba's oil," oversight of them appeared not to be a priority.

Recommendation #5.8: Government has an important role to play in being aware of, and actively monitor, major capital projects like Keeyask and Bipole III. Government is responsible to Manitobans and should fulfill that responsibility by expecting regular reports and asking questions about project progress and holding Crown corporations like Manitoba Hydro to account through the responsible Minister. The Minister should be held responsible for the level of knowledge of the Government and, in terms of project risk, the Minister should report on activities to do with project variance and risks to Cabinet. To do so, the Minister must be aware of emerging risks and question the project managers regarding details of their mitigation plan(s) and hold them to account for their performance against the approved plan(s).

501 Information received from participant, February 13, 2020.
502 Information received from participant, March 25, 2020.
503 Information received from participant, February 18, 2020.

CHAPTER 6

Recommendations for the Future

> *"While Manitoba Hydro management is accountable for its failures through these projects, the MHEB is the organization that is tasked with holding them to account, and until the change in 2016, at no time did the MHEB require better performance from the senior management."*

In accordance with Part B of the Terms of Reference the Commissioner was asked to make recommendations about the following matters:

1. How should Manitoba Hydro's and the government's oversight of any similar project proposed in the future, including the planning, approval, procurement and construction processes for the project, be strengthened to ensure that
   - (i) That there is appropriate transparency and accountability for decisions;
   - (ii) The commercial risk associated with the project is appropriately evaluated and allocated both on an individual project and on a systemic basis; and
   - (iii) The financial and fiscal implications of the project for Manitoba Hydro and the province are assessed in an appropriate and timely manner?
2. Should Manitoba Hydro's statutory mandate be clarified to ensure that decisions concerning any such future project are in the best interests of Manitobans?
3. Should the planning and approval processes for such a future project include additional regulatory approvals or an external review? If so, what form and manner should the regulatory approvals or external review take?
4. If such a future project is approved to proceed, how should the project oversight process be improved so that
   - (i) Changes in circumstances are accommodated in a timely and cost-effective manner; and
   - (ii) Verification is carried out at appropriate junctures to ensure that the project continues to be in the best interests of Manitobans?
5. Are there prudent steps for the government and its Crown corporation Manitoba Hydro to take to restore the corporation's financial health, given the government's ongoing obligation to ensure that provincial finances are managed responsibly and that Manitoba has an attractive investment environment?

Many of these issues have already been addressed in Chapters 1 through 5. This chapter provides additional discussion and recommendations on these matters.

STRENGTHENING OVERSIGHT

Oversight of the future projects of Manitoba Hydro from planning through construction can be strengthened through the full implementation of some specific planning and management tools at the corporate level and a close integration and acceptance of the legislative responsibility resting first in the Minister responsible and, ultimately, Cabinet and the Premier.

Integrated Resource Planning (IRP)

Manitoba Hydro made its decisions for new generation based on a load forecast, and in this case, the temporal nature of a prospective potential large industrial load project that did not ultimately occur (the Energy East pipeline). The systemic implementation of a robust, public IRP process will provide the broad-based and integrated plan against which Manitoba Hydro's prospective projects can be measured. If this is done objectively and transparently, it can negate the potential for pre-determined outcomes. A robust, public IRP process will also provide opportunities for interveners to participate in the on-going development of Manitoba Hydro's resource planning process and be provided information as the process develops, so that by the time there is a regulatory hearing (e.g., a public review of a major new facility), there should be less new information and points of contention. In this way, a public IRP process should reduce the duration of regulatory hearings.

Enshrining the requirement for IRP in legislation as proposed in Bill 35 is an important action by the Government to bring Manitoba Hydro into alignment with modern utility management practice. Recommendation #1.1 cautions against a purely internal development of the IRP and recommends a public, transparent process to develop and update the plan. The Commission notes that IRP was the subject of a study prepared for the Government in 2016[504] and also notes that Manitoba Hydro has been making great strides to bring this modern planning tool into its internal processes spurred by the new leadership of the company.

Internal Processes with Respect to Planning, Approval, Procurement and Construction

Manitoba Hydro has a long history of construction of both generation and transmission projects, and by all measures the projects that it delivers are engineered with skill and ultimately constructed in a professional manner as would befit the long-term nature of the provincial electrical grid that Manitoba Hydro is responsible for. Weakness was seen in the planning stage for Bipole III, where new technology was specified and included in cost estimates and it was assumed that the technology would be implementable as the project progressed. The implementability of this technology choice was not reviewed for more than three years. This allowed the project to proceed through environmental approval with a price tag that materially understated its actual cost and contributed to lack of oversight by Government. While a large project, the cost of Bipole III was not of particular note other than the debated $400 million incremental cost associated with the route change. There was heated debate over the then estimated incremental cost of $400 million to $900 million (depending on the speaker) for a project with a budget of $1.8 billion. One can only speculate as to the volume level and the nature of the questions if it was known at the time that this project would have an estimated cost of $4.6 billion.

A much deeper understanding needs to be reached by decision makers (particularly in government) of the vagaries and uncertainty of project estimating as a project goes through the various stages of approval. Internal Manitoba Hydro staff were estimating project costs of $4.1 billion as early as 2011, but this was adjusted to $3.28 billion in order to get MHEB approval. Government had already seized the earlier estimate of $2.2 billion and enjoyed many hours of debate with the opposition as to whether the $400 million increment for the west side route was worthy. Little did they know that the control budget in 2014 would be $4.6 billion.

504 Blaine Poff Power Consulting Inc., "Recommendations to Government's Questions for the Adoption of Integrated Resource Planning by Manitoba Hydro", September 30, 2016.

The stage gate process set out in Recommendation #4.4 will strengthen the ongoing evaluation of future projects and, if stage gating is developed with a clear understanding of the ultimate "go/no go" point, then legitimate review can take place with two possible outcomes. These points need to be identified up front and project abandonment accepted as a possibility. At each point, a new set of information will be available, and Manitoba Hydro should make a fresh decision as to whether it makes sense to proceed with the project from a commercial (and ratepayer impact) perspective.

The review at these points should be marked by a report to the Government on changes in the project cost and the business case, so that the Government can decide whether it would still like its Crown corporation (Manitoba Hydro) to pursue the project in light of the new information.

Accountability

Throughout both the Bipole III and Keeyask history the MHEB was presented with ever increasing budgets until eventually the projects were built and could not cost any more. The MHEB certainly raised these issues with management and asked for updated estimates, but in each case, they ultimately went along with all of the budget increases sought. This is not an example of an appropriate accountability framework and did not lead to better performance by management in terms of better accuracy or cost containment until the recovery plan for Keeyask was instituted in 2016/17. While Manitoba Hydro management is accountable for its failures through these projects, the MHEB is the organization that is tasked with holding them to account, and until the change in 2016, at no time did the MHEB require better performance from the senior management.

Recommendation #6.1: MHEB is the body to whom Manitoba Hydro's management is responsible. To improve the accountability and therefore the performance of management, the MHEB must:

1. Expect more accurate demand forecasts or identify the uncertainty and mitigate it, either by delaying decisions or ensuring that sufficient risk reserves are in place.
2. Expect more accurate cost estimates. Wuskwatim, Bipole III, and Keeyask have been significantly over the original control budgets. Simply creating another increased control budget without accountability is not careful management by the MHEB.
3. Management must be held accountable for the accuracy of information presented to the MHEB for decision.

The foregoing recommendation may seem to be obvious, but the history of MHEB decisions does not show a commitment to these actions and the Commissioner recommends that the Government make these statements part of the expectations of the MHEB.

As noted throughout this report, the requirement for regular reporting by Manitoba Hydro to the Government through the Minister would be of assistance and consistent with the shared accountability notion described above. During its review, the Commission found that reporting was at best ad hoc and that there was no formal reporting structure to the Minister that included regular meetings, minutes, and follow-up reporting to Cabinet regarding the major capital development activities of Manitoba Hydro. This was in the face of projects that would massively increase the provincial debt as guaranteed by the Province. The Commissioner believes that the Legislature should also be informed of the progress of projects on a regular basis for appropriate debate. A strengthened and formalized reporting structure between Manitoba Hydro and the Government will allow full accountability for performance. The Commissioner notes that Bill 35 requires Manitoba Hydro to present its annual business plan to the Minister each year and enshrining this in legislation provides a useful signal of government oversight. However, there should also be regular reporting to the

Minister about major new capital projects, specifically, and more frequently. This is addressed in Recommendations #4.9 and #5.8 and will strengthen the ongoing evaluation of future projects.

Commercial Risk

Oversight of the commercial risk associated with the construction aspects of Keeyask and Bipole III was lacking, with slow updating of actual costing in the case of Bipole III and clear lack of oversight of the GCC contract with respect to Keeyask. The review of project management capacity by Stantec in 2012 indicated that the processes (other than cost control) were in place[505] so the focus should be on execution error rather than a lack of structures to provide the oversight within Manitoba Hydro. Holding management accountable for their management performance would be the most useful change to the oversight framework in this regard.

The assessment of the commercial risk with respect to the project as a whole deals with the financial plan assumptions upon which the project rests. This risk was most certainly present in the Keeyask project, but also exists as part of the nature of Manitoba Hydro's economic structure.

Manitoba Hydro has always been a seller of surplus power to export markets both in Canada and the United States. The nature of hydroelectric generation creates this opportunity and in high water years the company has enjoyed an abundance of surplus power that can be sold for profit to others. There is no doubt that this opportunity has had a positive effect on the profitability of the company with the attendant virtuous effect of reducing electrical rates for Manitobans and supporting a low-cost energy infrastructure with which to attract industrial development in the Province.

Initially conceived as a profitable use of inevitable surplus, the attractiveness of export markets and export pricing saw Manitoba Hydro propose and build the Wuskwatim dam in advance of domestic need to supply an attractive export market at the time. The project went through a modified NFAT/CEC process and was approved. A relatively small development, Wuskwatim was an "assay in the art" of merchant dams that was replayed in the Keeyask planning and approval process.

The logic for an early build of generation supported by firm export contracts until needed by domestic load is a well-known argument made often by politicians and Manitoba Hydro leadership alike. It stands on the success of historical earnings and their positive impact on the rate and assumes that this formula is foolproof. As long as the firm contracts can support the operating and capital costs of the project it appears to be a reasonable approach. The ultimate safety net in these ventures is the evolution of the "merchant" aspects of the dam to a more "utility" based identity as the generation is required for domestic use. The question is one of risk. As long as the firm energy contracts can stay in place and remain profitable, the dam will be parked awaiting emergent domestic need and the plan holds together. But what happens if domestic demand is delayed beyond the firm contract expiry? What happens if the firm export contracts have to be re-signed but at lower prices? Who makes up the difference in revenue from a project that is subject to all the risks inherent in normal commercial ventures? Under the current framework this risk is borne by the ratepayer.

This is precisely what has happened with the request from Manitoba Hydro for significant rate increases to deal with a poor outlook and a "failed" financial plan. The Commissioner finds this risk to be misaligned with decision makers that decide to take the risk and pass on the cost to the ratepayer if they are wrong.

505 Stantec, "Manitoba Hydro – New Generation Construction Division, Review of Program & Project Management Best Practices," 2012, pp. 12-13.

Decisions to invest in commercial operations for export can only be made with the formal approval of Government, as was the case with Keeyask. In the future, the Commissioner proposes that the risk associated with new generation that will, for an extended period of time, be commercial in nature be aligned with those that benefit. For hydroelectric generation, the Government receives incremental income from the development in the form of water fees, capital taxes, and loan guarantee fees. A potential accountability tool would be to put those fees at risk if a commercial venture does not meet its market expectations as proposed in Recommendation #2.6.

This will assist the Government in properly assessing the efficacy of investing in the commercial ventures in the future and put its budget at risk for decisions that are made rather than the ratepayer. Adding this accountability would greatly improve decision making at the government level.

Government may wish to add this to their new legislation for future hydroelectric development.

Financial and Fiscal Implications

The inclusion of a Treasury Board review of Manitoba Hydro capital plans will close the loop of the review process and broaden the scope of review to include the guarantor of Manitoba Hydro's debt. The implications of these large debt financed projects on the Manitoba Government's overall financial structure must be considered and the review recommended in Recommendation #1.2 will bring analysis heretofore untapped to projects than can (as is the case with Keeyask and Bipole III) double the provincial debt.

STATUTORY MANDATE

The Manitoba Hydro Act

The Commissioner recommends that the Government consider clarifying *The Manitoba Hydro Act* to better define the duties of Manitoba Hydro as they relate to the provision of domestic power and the pursuit of commercial export opportunities as described in Recommendation #4.10. This issue is just one that the Commissioner recommends be the subject of a process to develop an energy policy for the Province of Manitoba.

Energy Policy

The changing environment of power generation will place pressure on all power utilities, including Manitoba Hydro. Grid parity has been achieved in parts of Europe and the United States and this will only accelerate in the years to come. Manitoba Hydro has a $32 billion investment in grid power and sells a significant portion into a commercial market. It is reasonable to expect the market to change in the coming years. From a domestic perspective, the Government will need to grapple with the desires of its citizens to produce their own renewable power while still having the provincial grid as a backup. The issue of grid abandonment is topical everywhere in Canada and takes on even more importance when one considers the large industrial sector that may well consider its own generation if rates rise above their own-generation cost of production.

The challenges facing Manitoba Hydro in the future will need the guidance of an energy policy that provides policy space for the future as described in Recommendations #1.5, #1.7, #2.12, and #4.10. The policy will inform Manitoba Hydro's IRP and allow for a public and transparent position to be proclaimed. Public involvement in the development of this policy is critical and the process should begin as soon as practicable.

PLANNING AND APPROVAL PROCESSES

The Commissioner believes that the structures exist for robust and complete review of projects in the future. The MHEB, the PUB, the CEC, and the Government through entities such as the Treasury Board have all of the tools needed to ensure complete analysis of prospective projects and Bill 35 provides legislated authority to do so. Prescribed processes such as an NFAT with triggering characteristics such as project cost provide guidance to the system to ensure that the reviews occur. Additional requirements such as IRP and formal stage gating review ensure that the processes are more than optics and actually provide the full information required to make better decisions.

What could be added to the already properly prescriptive actions noted in Bill 35 is the ability for the decision entities to vary their processes to provide complete analysis. During the NFAT, the NFAT Panel was under a hard deadline and had to accept incomplete analysis and information prior to making its recommendation. The NFAT Panel did not have the ability to extend the hearings and with Manitoba Hydro already mobilizing for a start to the project just two months away there was enormous pressure on the NFAT Panel to just make the recommendation. For a properly functioning review of that magnitude there must be the ability for the regulator to ensure that its work is complete. Schedules are important, but in the case of a multibillion-dollar project with a planned life of 78 years it seems wrong that a full review would lack for just a few weeks. Some method of giving this authority to the regulator should be considered.

Other recommendations related to planning and approval processes include:

- the requirement for an independent technical assessment of whether a proposed major capital project is necessary and should be pursued over other possible alternatives, as well as the reasonableness of Manitoba Hydro's underlying forecasts, along with an assessment of whether a proposed major capital project is consistent with provincial energy policy;
- evaluating projects and development plans using a study period that is significantly shorter than 78 years;
- the evaluation of any large-scale project must include any other new project or facility upon which it is dependent (for example, how Keeyask was dependent on Bipole III);
- limits should be placed on how much advanced costs can be spent on a major capital project prior to final approval and sanctioning of that project;
- Government should strengthen its internal oversight processes to ensure Cabinet is fully aware, on an ongoing basis, of the need, benefits and risks of Manitoba Hydro capital projects;
- members of the PUB should be appointed for long terms with limited ability for the Government to terminate them during their terms, in order to ensure that members are less sensitive to politics in making their decisions; and
- CPV should be used as a metric for economic analysis along with NPV, in order to capture important information regarding the timing of costs and benefits of a project or development plan through the study period.

PROJECT OVERSIGHT AFTER APPROVAL

Once a project is sanctioned, the project plan will certainly have standard, Manitoba Hydro internal oversight methodologies in place. The key areas of uncertainty and the underlying economic assumptions for a project should be identified and become the agenda for regular and frequent updates to the Minister.

Deviation from the plan and changes in underlying assumptions should be disclosed and reviewed with the Minister as the project progresses and reported through to Cabinet.

Other recommendations related to post-approval oversight include:

- for any future major capital project like Keeyask or Conawapa, the Government should create a formal management structure to oversee the project, similar to what was put in place for Conawapa in the 1990s (Recommendation #2.10);
- the MHEB and Minister Responsible for Manitoba Hydro must have a complete understanding of the kind of contract being recommended by Manitoba Hydro management as to cost overrun risk exposure, which could come from enhanced reporting to the MHEB and the Minister and from a formal management structure to oversee any future major capital project, as recommended above (Recommendation #4.5);
- the MPEC or a structure with similar, direct executive involvement (including Manitoba Hydro's President and CEO) should be in place at the beginning of any future large-scale capital project at Manitoba Hydro (Recommendation #4.12);
- Manitoba Hydro should use the services of an external construction management expert for future high-value capital projects and those with cost reimbursable payment structures, who could help Manitoba Hydro with effective cost controls and risk management (Recommendation #5.1);
- for any future major capital project that Manitoba Hydro proposes to construct, it should be required to demonstrate available capacity for project management through internal and/or external resources (Recommendation #5.2);
- the PUB should carefully scrutinize the costs incurred by Manitoba Hydro with respect to capital projects like Keeyask and any costs incurred by Manitoba Hydro that are not prudent should be excluded in the PUB's calculation of rates (Recommendation #5.3);
- the MHEB must be provided with accurate, timely, and complete information on all material aspects of project development – including regarding project management risks and cost overruns – so that it can properly discharge its duties and make good decisions (Recommendation #5.5);
- there should be regular briefings from the Chair of the MHEB and the CEO of Manitoba Hydro to the Minister Responsible for Manitoba Hydro, in addition to any project-specific briefing recommended in this report (Recommendation #5.6); and
- the Chair of the MHEB must ensure that the MHEB has the capacity to evaluate management proposals and hold management to account, as is its duty (Recommendation #5.7).

PRUDENT STEPS TO IMPROVE MANITOBA HYDRO'S FINANCIAL HEALTH

The financial health of Manitoba Hydro took centre stage with the 2017/18 GRA. Due to the significantly increased construction costs of Keeyask and a softening export market, Manitoba Hydro proposed a dramatic series of rate increases to return the company's financial ratios to pre-development levels.

While this application for five years of 7.9% rate increases was denied it highlighted the additional risks Manitoba Hydro faces in a time of significant capital investment. Important measures of financial health for Manitoba Hydro are debt-to-capitalization ratio, interest coverage ratio, and capital coverage ratio. It is expected, and was presented during the NFAT, that many of these financial ratios would deteriorate upon the completion of Keeyask and Bipole III due to the significant increase in debt and the debt servicing costs therein.

The impact of the weakening of these ratios is a reduced ability for Manitoba Hydro to address the systemic risks it faces associated with water levels, weather impact on demand, and revenue risk in the commercial export markets. There is also the concern that Manitoba Hydro's financial structure could affect the debt markets for the Government of Manitoba should the company's debt be deemed not supported by their business activities.

The Commissioner notes that the Government has taken steps to provide guidance to Manitoba Hydro with respect to improving its financial metrics. Bill 35 legislates a series of debt-to-capitalization ratios that over a 20-year horizon will return Manitoba Hydro to a 70/30 capitalization ratio.[506] The Bill allows rate increases to provide sufficient revenue to achieve these targets.

The Commissioner believes that this element of Bill 35 recognizes that the major risks associated with Manitoba Hydro's income statement are by and large outside of its control. While the magnitude of the risks has been increased, the tools to address them have not. As noted earlier, Keeyask is going to depend on export revenue for many years, a revenue source that is subject to water levels providing supply for opportunity sales, the vagaries of a competitive export market changing rapidly as new technology is deployed, and an unpredictable regulatory environment subject to political winds of change. The time frame proposed and the full expectation that rate increases can be used to meet these targets gives a clear message to the markets that Manitoba Hydro will be self-sustaining and will improve its financial ratios in the future. Thus, the question of the sustainability risk of unsupported debt is mitigated for the capital markets.

By relaxing the debt-to-capitalization ratio for a period of time, the Government has recognized the reality of large capital expansion and provided the company with the flexibility to meet the targets over a long planning horizon. However, with this breathing space comes responsibility.

To minimize the rate increases, it may require that Manitoba Hydro execute its management and export marketing plans with great skill and be accountable for its performance within the elements it controls. Increasing revenue, vigorous cost containment, and reducing debt should be the complete focus of Manitoba Hydro in the coming years.

To increase revenue the company may consider exploring partnerships in transmission- particularly in the international export market which could provide incremental capital to the corporation and reduce the risk that exists in the debt refinancing planned for the next five years.

The Commissioner believes that Manitoba Hydro should look at its various subsidiary elements and determine if those operations are core to its mandate and duty. If these are not core to its mission, then they should be considered for sale or shutdown. Monetization of assets could help relieve the debt burden sooner and reduce rate increases in the future. This will also allow management to focus on its core responsibilities with a particular emphasis on execution of its business plan without the distraction of managing operations in other sectors.

The Commissioner understands that the consideration of the future of non-core subsidiaries requires a more flexible policy framework than was available in the past, but believes that the ratepayers of Manitoba deserve every opportunity to maintain their low electricity rates and Manitoba Hydro needs to focus on this without distraction. The major generation and transmission capital plan nearing its completion brings new and magnified risk to the company and there is little room for error in the changing world.

506 Bill 35, *The Public Utilities Ratepayer Protection and Regulatory Reform Act* (Various Acts Amended), 3rd Sess., 42nd Leg., 2020, s. 39.1(1)(c) (i).

The Commissioner would like to acknowledge and encourage the work of Manitoba Hydro, previous and current Manitoba Governments and the federal government for pressing the opportunity for export sales to other Canadian provinces.

In October of 2018 Manitoba Hydro announced the sale of 215 MW to the Saskatchewan power utility SaskPower beginning in 2022. In March 2020, the federal government announced $18.7 million in funding to support the construction of the new transmission line required to carry the electricity sold in this agreement thereby increasing the use of emissions free Manitoba Hydro power by Saskatchewan residents and businesses. In this report, the Commissioner recommends that Manitoba Hydro focus on its core functions as it rebuilds its balance sheet and assures the Manitoba low electricity rate advantage for the long term. The Commissioner believes that export sales to other provinces, including federal government support and a Canadian vision for a western Canadian and national grid, is worthy of inclusion in any list of core activities.

Credit is due to previous premiers and Manitoba's current premier especially for making the strong case for a national (and at the very least a western Canadian) grid a priority for national discussion and consideration.

The Commissioner offers its encouragement and support for this effort and for the pursuit of export sales to other provinces, with federal government support.

SUMMARY

Manitoba Hydro is a precious asset of the people of Manitoba. It has provided reliable service at low rates for decades. However, through over-optimism with respect to the opportunities in the export market and a pre-determined development path with no available off-ramps, the company has overbuilt the generation assets needed for domestic use for many years. The company is now more exposed to risk and, as always, the ratepayer stands as the guarantor.

Historically one could take the position that the domestic need will appear at some time in the future and the investment will be proven acceptable, just maybe a little early. The modern electrical generation landscape makes that claim less certain. Grid parity, grid abandonment, changing economics, and the impact of climate change on water levels for hydroelectric power generation make the future position of large-scale grid power uncertain. There is no question that Keeyask will generate electricity for many decades and Bipole III will provide reliability and, with the intertie, will dutifully transmit the power to a large U.S. market. The future economics have proven difficult to predict through all of the reviews and the Commissioner will not opine on what may happen in the coming years. What it can do is offer the encouragement to Manitoba Hydro and the Government to control what they can and make decisions based upon a somewhat less optimistic forecast - but one that always has hope.

The Government and Manitoba Hydro will be tasked with finding their path in this new environment and the Commission believes that the formation of reasonable policies and the commitment to best practices will prevail in the uncertain future of electrical supply and markets.

List of Recommendations

In response to Order in Council 301/2018[507] and the Terms of Reference attached thereto, the Commissioner makes the following recommendations:

Recommendation #1.1: Transmission and generation should both be considered in an ongoing IRP process. If there is a need (e.g., for reliability), it should be discussed in such a process along with potential solutions. A need should not be allowed to go unaddressed for decades until a solution for that need can be justified by a profit motive, as was the case for Bipole III. An IRP process involves the consideration of alternatives well in advance of when a business case for an option is finalized and ready for regulatory review. The Commissioner supports changes proposed in Bill 35, whereby Manitoba Hydro will have to regularly prepare and submit to the Minister an IRP, taking into account government policies, risk, and financial targets, among other things. However, the Commissioner is of the view that this IRP, while led by Manitoba Hydro based on criteria set by Government, should be developed through a public process involving independent experts and overseen by an independent regulator such as the PUB, rather than by Manitoba Hydro alone.

Recommendation #1.2: The Commissioner is supportive of the changes in Bill 35 that would require Treasury Board approval for Manitoba Hydro's capital expenditure programs. This provides a process by which government (a party other than Manitoba Hydro) can assess the financial implications of a proposed capital expenditure program or project like Bipole III on the Province and taxpayers. Bill 35 would also require a review by the PUB for any new transmission line with a voltage higher than 230 kV, if $200 million or more of investment is required by Manitoba Hydro. Such reviews would consider impacts on rates and Manitoba Hydro's financial health. In the Commissioner's view, an independent technical assessment of whether a proposed project is necessary and should be pursued over other possible alternatives, as well as the reasonableness of Manitoba Hydro's underlying forecasts, should also be required, along with an assessment of whether a proposed project is consistent with provincial energy policy.

Recommendation #1.3: The Government should pursue Indigenous partnerships including equity, means of mitigating project impacts (e.g., modified routing within a preferred corridor), and other means of **addressing** concerns when a particular project is the most economical way of providing for the supply of power adequate for the needs of the Province, as opposed to rejecting the most economical option out of hand in favour of a more expensive option.

Recommendation #1.4: The Government needs to be aware of and transparent about the incremental costs of constraints and additional requirements that its policies impose on Manitoba Hydro with respect to its projects (e.g., route siting). While it is reasonable to expect a Crown corporation like Manitoba Hydro to adhere to government policies, those policies must be explicit and transparent so that the Government can be properly held accountable for them and their incremental costs. Those policies should be reflected in a policy statement published by the Government.

507 Appendix A, Tab 12.

Recommendation #1.5: The large and long-term investment in hydroelectric power generation requires the Government to provide guidance to Manitoba Hydro with respect to energy policy. This energy policy should address "merchant plants" if they are to continue being built in the future, including criteria for their commercial evaluation and the extent to which exports (firm and opportunity sales) may drive or advance the development of new generation by Manitoba Hydro.

Recommendation #1.6: Manitoba Hydro, the PUB, and the Government of Manitoba should not respectively pursue, recommend, and approve a multibillion-dollar project based on a need date advanced by multiple years to serve last-minute load forecasted for a small number of customers. If a major project is being built based on a need date to serve load for a small number of customers, that load should be vigorously vetted and verified ahead of time as part of the mandatory public review of such a project (as discussed in other recommendations). The Commissioner notes that Manitoba Hydro's load forecasts include a sensitivity analysis, including around the increase or decrease of one very large industrial customer and that, since the NFAT, Manitoba Hydro has changed the forecasting methodology for potential large industrial load in response to direction from the PUB, resulting in a more conservative methodology and significantly reduced load forecast.

Recommendation #1.7: The Commissioner concurs with the PUB's call for a comprehensive and regularly occurring IRP process in which DSM will be evaluated as a stand-alone resource and placed on an equal footing with other energy resource options. The Commissioner acknowledges that IRP is part of Manitoba Hydro's new management plan, which marks an improvement to the previous resource planning process, and that Bill 35 will mandate IRP.

In the Commissioner's view, this IRP process should be led by Manitoba Hydro based on criteria set by the Government but developed through a public process involving independent experts and overseen by an independent regulator such as the PUB.

Recommendation #1.8: The Commissioner agrees that independent expert consultants made useful recommendations during the 2017/18 GRA that Manitoba Hydro should consider implementing into its load forecasting methodology, particularly regarding elasticities, scenario analysis, and use of longer-term data to estimate weather-dependent load. The Commissioner supports the PUB's direction for Manitoba Hydro to provide details of the implementation of these recommendations, or reasons for not implementing them, at the next GRA.

Recommendation #1.9: Given the inherent unreliability in long-term forecasts, projects and development plans should be evaluated using a study period that is significantly shorter than 78 years (the length of the period used during the NFAT). Benefits forecasted over the long term should not be relied upon to justify a project or development plan that does not make sense within a reasonable time frame (e.g., the 35-year detailed analysis period used during the NFAT).

Recommendation #1.10: While it may be reasonable for Manitoba Hydro to negotiate agreements for project construction and agreements with impacted Indigenous groups to establish costs of a project, these contracts should not influence a decision to proceed with a project before it is actually needed or approved. Such agreements should not be executed until after project approval or sanctioning, or if execution occurs beforehand, Manitoba Hydro should ensure that it has the right to terminate the agreement without any material penalty or delay the effective date of the contract if a project is not needed until further in the future. Furthermore, as recommended in more detail in Chapter 2 of this report, limits should be placed on how much advance costs can be spent on a major capital project prior to final approval and sanctioning of that project.

Recommendation #2.1: The Government should commission an independent review and public report regarding transmission tariffs, access to transmission in the Province, and related government policies to ensure that they are not a barrier to other companies building new generation in Manitoba for export, in accordance with its policy of allowing same. Fostering competition for merchant plants will likely drive efficiencies and cost reductions for all such projects, including those pursued by Manitoba Hydro.

Recommendation #2.2: The Government of Manitoba and Manitoba Hydro should consider P3 arrangements for any future high-value capital projects. Under a P3 model, the allocation of risk and cost overruns to the private partner(s) on a project like Keeyask may make this option more favourable than the classic design/build/own model. Keeyask has experienced significant cost overruns and delays like many other public infrastructure projects, at least in part because Manitoba Hydro is not a construction manager. By contrast, cost overruns and delays are less common on P3 projects, in which risks and responsibilities are allocated to the private sector based on its areas of expertise (e.g., construction management). Such a P3 arrangement could include a takeout option in the future and help avoid multibillion-dollar cost overruns in the future.

Recommendation #2.3: The Government should be open to equity options or other opportunities with Indigenous partners for all activities, including transmission projects like Bipole III. In addition to helping to fulfill the goal of reconciliation, such partnerships with Indigenous peoples may help to ensure that projects can be completed on schedule and on budget by allowing Manitoba Hydro to proceed with its preferred development option without delays caused by Indigenous opposition.

Recommendation #2.4: The Commissioner believes that the requirement in Bill 35 for public review and Cabinet approval of any new power generating station with a peak capacity of at least 200 MW, and any new transmission with a voltage of at least 230 kV, that will require an investment by Manitoba Hydro of $200 million or more, is reasonable. However, the Commissioner would propose that this mandatory public review should include an evaluation of any other new project or facility upon which the new generating station or transmission line is dependent (in the way that Keeyask was dependent on Bipole III to transmit power that it produces).

Recommendation #2.5: Limits should be placed on how much advance costs can be spent on a major capital project prior to final approval and sanctioning of that project. The only costs that should be incurred prior to a major project's approval are for activities required to assess the merits of the project (such as preliminary engineering and environmental work, Indigenous engagement, and, in some cases, costs to negotiate material agreements provided that the agreements can be cancelled if the project does not proceed – as discussed in Chapter 1). Prior to the major project being approved, costs should not be incurred that unnecessarily constrain the subsequent decision-making process.

Recommendation #2.6: Manitoba Hydro's ratepayers should not bear the risk associated with new generation projects that will, for an extended period of time, be commercial in nature, used for exports, and not needed to serve domestic demand. In other words, they should not be used as involuntary equity investors for projects to serve export demand in a risky market. Since it is the Government that approves export contracts and new generation projects like Keeyask, not ratepayers, and the Government that benefits (through water rentals, capital taxes and debt guarantee fees from Manitoba Hydro) even if such projects do not turn out well financially (as discussed in Chapter 4), it is the Government that should bear this risk. Accordingly, if a Government in the future approves a generation project that is, for an extended period of time, primarily for export and not needed for domestic demand, then the Government should bear the risk if this commercial plant is not successful during that period. If the market plan fails and export revenues do not cover the costs of operating the plant during that period and the proportion of capital costs for that part of the plant's operating life, then the Government should reduce or suspend its collection of transfers from Manitoba Hydro until those cost shortfalls are made up. This will have the effect of putting government's budget at risk for decisions that are made by Government, rather than ratepayers.

The Commissioner believes that this recommendation will add accountability that will improve decision making at the government level and will provide a proper incentive to the Government of Manitoba to provide greater oversight and accountability with respect to any future major capital projects.

To implement this recommendation, Government may wish to legislate a reduction or suspension in the transfers that Manitoba Hydro is required to pay to the Government in the circumstances set out above.

Recommendation #2.7: As recommended in Chapter 1 of this report, the Government should develop new policy regarding merchant plants that includes evaluating the commercial merits (i.e., profit potential) of those projects differently than projects built to serve domestic demand. In addition, the Government should develop new policy regarding the extent to which exports should drive or advance the development of new generation by Manitoba Hydro. This policy should address how much of those exports should be supported by firm sales agreements (as opposed to opportunity sales).

Recommendation #2.8: Treasury Board should continue to monitor the financial health of Manitoba Hydro. This should include the continued review of Manitoba Hydro's annual operating and capital budgets against financial targets set by the Government. This would provide the Government with an oversight process involving its financial experts reviewing these plans and advising the Government on their financial implications for the Province and, by extension, the public.

Recommendation #2.9: Government should strengthen its internal oversight processes to ensure Cabinet is fully aware, on an ongoing basis, of the need, benefits, and risks of Manitoba Hydro capital projects. The intent would be to assess projects proposed by Manitoba Hydro before public regulatory bodies review them. This would likely require additional resources with the capacity to understand complex economic and technical energy matters. The benefits of such a measure would significantly outweigh the costs given the magnitude of the impacts mega-projects have on the provincial economy.

For example, the Crown Services Secretariat could assess the rationale for the need for new generation and transmission and confirm options that have been comprehensively considered.

Recommendation #2.10: For any future major capital project like Keeyask or Conawapa, the Government should create a formal management structure to oversee the project, similar to what was put in place for Conawapa in the 1990s. Within that structure, there was involvement at all levels from various ministries (including the Ministry of Industry, Trade and Tourism that existed at the time). If such a structure is used on a major capital project that is underpinned by export contracts to the U.S., like Keeyask, there could be similar involvement from the Department of Intergovernmental Affairs and International Relations and it could provide advice regarding U.S. policy affecting export opportunities.

Recommendation #2.11: Manitoba Hydro's statutory mandate should be amended to provide clarity in terms of its objectives and priorities. In the Commissioner's view, Manitoba Hydro's statutory mandate should not include socio-economic development. Rather, Manitoba Hydro's mandate should be to provide the most economic and efficient electric system within the boundaries of the Province's energy policy (which should not pre-determine projects or resource options). Manitoba Hydro should pursue and choose projects based on lowest cost and technical performance, not based on socio-economic development benefits. Issues of socio-economic development are broader matters of public policy and the responsibility of Government. It is the Government that is the custodian of the economy and pursues social policies in the collective interest. .

If the Government decides that Manitoba Hydro should pursue and choose a project based on socio-economic development benefits, rather than lowest cost to ratepayers, the Government must be publicly transparent about that decision so that it can be held accountable, and taxpayers should be responsible for the incremental costs of that policy decision, not ratepayers.

Recommendation #3.1: Manitoba Hydro's assessment of project alternatives must be flexible enough to account for changes in underlying assumptions up to the point in time when a final approval/ sanctioning decision is made. Often, a project gains momentum as it proceeds through the planning phases. However, before significant long-term capital is invested in a project, it is critical for the ultimate decision makers to make a fresh, objective assessment of the need for the project and whether it should proceed instead of other possible alternatives. The PUB's review process should similarly ensure that projects are not recommended to proceed unless they are the best solution for the Province, based on the best available information at that time.

Recommendation #3.2: The Government should ensure that the timelines provided for public reviews of major new facilities are reasonable in light of the scope of such reviews and their terms of reference. The PUB must have the ability to request an extension if more time is necessary to complete a review of a major new facility, including if more evidence is needed to fulfill its mandate.

Recommendation #3.3: Members of the PUB should be appointed for long terms with limited ability for the Government to terminate them during their terms, in order to ensure that members are less sensitive to politics in making their decisions. Currently, *The Public Utilities Board Act* provides that each member of the PUB holds office during pleasure of Cabinet (i.e., Cabinet can terminate them at pleasure). Some provinces have legislated minimum terms for members of utility commissions and boards. The Government of Manitoba should consider amending *The Public Utilities Board Act* to include such minimum terms for members of the PUB.

Recommendation #3.4: Unless Manitoba Hydro is directed by the Government to pursue and choose a project based on socio-economic benefits, such benefits should not be considered in the assessment of a development plan or project unless more than one development plan or project are equal in terms of cost and technical performance. The primary assessment of a development plan or project in terms of cost and technical performance is consistent with Manitoba Hydro's current (and recommended) mandate to "engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power."

If Manitoba Hydro is directed by the Government to pursue and choose a project based on socio-economic benefits, rather than lowest cost to ratepayers, the socio-economic benefits of a development plan or project should be evaluated against its incremental costs relative to the lowest-cost option (which, as stated in Recommendation #2.11, should be borne by taxpayers, not ratepayers).

Recommendation #3.5: In addition to Recommendation #1.9, the Commissioner recommends that CPV be used as a metric for economic analysis along with NPV, in order to capture important information regarding the timing of costs and benefits of a project or development plan through the study period (and not just at the end of the study period, like NPV). CPV allows for economic analysis within more certain time frames and discloses intergenerational costs and benefits. Given the increasing unreliability of assumptions over time, this information captured by CPV should be considered in any economic analysis.

Recommendation #3.6: In identifying the preferred option to meet Manitoba's energy needs, alternatives should be assessed based on a "like to like" comparison of their individual merits. Only costs associated with the specific development plan being considered, as well as associated facilities required for that development plan, should be assessed as the costs for that development plan.

Recommendation #3.7: While it is reasonable for Manitoba Hydro to negotiate long-term power sales agreements, the contracts should not pre-determine the preferred energy supply option before that option has been approved and sanctioned. Similarly, the fact that a contract has been executed should not be the justification for proceeding with one resource option over another, otherwise preferable, option. To the extent that Manitoba Hydro enters into a power sales agreement that is contingent on a particular project proceeding that has not yet been sanctioned, Manitoba Hydro should ensure that it has the right to terminate the contract without any material penalty if that project is ultimately not sanctioned.

Recommendation #3.8: As noted in Chapter 1 of this report, the Commissioner concurs with the PUB's call for a comprehensive and regularly occurring IRP process in which DSM would be evaluated as a stand-alone resource and placed on an equal footing with other energy resources options.

Recommendation #3.9: As noted in Chapter 2 of this report, the Government should clarify Manitoba Hydro's mandate in selecting projects to meet future energy demand. If Manitoba Hydro's primary focus should be on impacts to ratepayers (as recommended by the Commissioner in Recommendation #2.11), then many "benefits" from the perspective of government should actually be assessed as "costs" from the perspective of ratepayers. Under its current statutory mandate to provide adequate supply of power for the needs of the Province, a public and recurring IRP process provides a framework to determine those needs and select the right supply option to fulfill them.

Recommendation #4.1: Manitoba Hydro should assess long-term risks and the compound risks of executing multiple projects together as part of the IRP process. For project-specific risk, the risk register should incorporate and address compound risk for the project. These changes would assist Manitoba Hydro in effectively identifying and managing risks.

Recommendation #4.2: The evaluation of risks of executing a project should include the risks associated with any other new project or new facility upon which it is dependent. For example, Keeyask was dependent on the construction of Bipole III. The assessment of Keeyask and of any other new generating station should include the risks associated with any new transmission project that is needed to transmit the power that it produces.

Recommendation #4.3: As a public utility whose performance affects the electricity rates paid by Manitobans and can have fiscal implications for the Province, Manitoba Hydro should design its cost estimates in a way that is more conservative to minimize the potential for cost overruns (as has occurred on Keeyask and, to a lesser extent, on Bipole III). These estimates should be as accurate as possible based on the project development stage and include a project contingency that is proportionate to the risks identified through a detailed risk evaluation for the project. At the time that the project is formally sanctioned, a P80 cost estimate should be developed by Manitoba Hydro, if possible, to better understand the risk of cost overruns.

Recommendation #4.4: Manitoba Hydro should use the industry standard "stage gate" approach for internal approvals of major projects like Keeyask and Bipole III. As part of this approach, there should be a "gate" at each major decision point during the project development process, whether that consists of a required internal approval from the MHEB, a decision that will result in significantly higher sunk costs, or a decision from which Manitoba Hydro will otherwise have difficulty returning (e.g., executing the GCC). This process should be designed with particular attention to the consideration and implementation of defined off-ramps so that the project can be stopped (e.g., once a certain amount of money has been spent on a project, before sunk costs are unreasonably high).

At each stage gate, Manitoba Hydro ought to re-evaluate the business case for the project to determine if such a case still exists, including an examination of whether the assumptions underlying that business case are still valid (e.g., domestic load and export market forecasts).

Recommendation #4.5: The MHEB and Minister Responsible for Manitoba Hydro must have a complete understanding of the kind of contract being recommended by Manitoba Hydro management as to cost overrun risk exposure. This understanding could come from enhanced reporting to the MHEB and the Minister and from a formal management structure to oversee any future major capital project (similar to what was put in place for Conawapa in the 1990s), which is addressed in Recommendation #2.10.

Recommendation #4.6: Manitoba Hydro should use the services of an external consultant for any future major capital projects to help with market-testing high value contracts such as the GCC and to help determine and design the appropriate contract structure, in order to minimize the risks allocated to Manitoba Hydro (and, by extension, its ratepayers) under those contracts.

Recommendation #4.7: Manitoba Hydro should structure its construction contracts for major projects in a manner that incentivizes the contractor to complete the project on time and on budget. Such incentives may be achieved through a fixed or unit price contract. If Manitoba Hydro elects to proceed with a cost reimbursable-target price contract, Manitoba Hydro should ensure that it carefully reviews all bids to ensure that the contract is designed to provide meaningful and effective incentives to the selected contractor.

Recommendation #4.8: The contract type for a high-value contract such as the GCC should be part of the mandatory public review process in respect of a major capital project that is contemplated in Bill 35, given that it is an important part of the risk management process. As part of that process, Manitoba Hydro should be required to justify a choice of contract type (which should be chosen with the advice of an external consultant, as discussed in Recommendation #4.6). If Manitoba Hydro decides to use a contract type for a major capital project that is not industry standard, such as the GCC, it should be required to justify that decision during public review and seek direction before executing the contract.

Recommendation #4.9: Government should play an active role in evaluating commercial risk associated with major capital projects undertaken by Manitoba Hydro. This is necessary in respect of a utility which, by virtue of being government-owned, has no other shareholders to whom it is responsible and by whom it is held accountable for its performance.

Crown corporations are very much like line departments when it comes to the principle of responsible government in a parliamentary democracy. Ministers and premiers must be held accountable for Crown corporation decisions. Accordingly, there must be regular reporting and communication from the Crown corporation to the Minister, as discussed further in Recommendation #5.8. This does not necessarily imply inappropriate interference as the Crown corporation seeks to pursue its legislated mandate on commercial terms. Rather, the accountability of the Crown corporation that comes from a regular reporting relationship can act as a safeguard for the shareholder from the kinds of things that occurred with respect to Manitoba Hydro in the matters of Keeyask and Bipole III. The Crown corporation must be accountable to the Minister who, along with rest of Cabinet is, in turn, accountable to the Legislature and the public.

Recommendation #4.10: As discussed in Chapters 2 and 3 of this report, the Government should revise Manitoba Hydro's statutory mandate as set out in *The Manitoba Hydro Act* to make it clear that Manitoba Hydro's mandate is to meet Manitoba's peak domestic load in the most cost-effective manner possible and not to maximize jobs in the north or carry out the Province's environmental policy, unless otherwise directed by the Government through a transparent process. It should not preclude Manitoba Hydro from exporting power provided it is done in accordance with provincial energy policy which, as recommended in this report, should provide guidance regarding exports including commercial targets for projects built for exports (regardless of whether they eventually are used to serve domestic demand).

Recommendation #4.11: The decision to build a project of the scale and cost of Keeyask should not be made until after the risks have been fully assessed, including the project's immediate and long-term fiscal implications for Manitoba Hydro (and its ratepayers) and the Province (and its taxpayers). As recommended in Chapter 1 of this report, the need for a project should be justified through comprehensive IRP completed by Manitoba Hydro and then reviewed by an independent regulator such as the PUB in a public proceeding.

Under Bill 35, the required NFAT of a major new facility should also include a full assessment of risk and fiscal implications.

Recommendation #4.12: As discussed in Chapter 5, the Commissioner views Manitoba Hydro's establishment of the MPEC as a good decision and a positive development in terms of project oversight, coordination, and accountability within Manitoba Hydro. The MPEC or a structure with similar, direct executive involvement (including the President and CEO) should be in place at the beginning of any future large-scale capital project at Manitoba Hydro. Such a structure helps provide clear lines of responsibility and executive oversight within the company.

Recommendation #5.1: The Commissioner concurs with the recommendation that Manitoba Hydro use the services of an external construction management expert for future high-value capital projects and those with cost reimbursable payment structures, who could help Manitoba Hydro with effective cost controls and risk management.

The Commissioner also concurs that Manitoba Hydro should continue implementing recommendations made by MGF and KCB. Manitoba Hydro should also report on its implementation of recommendations in the Keeyask health check that KPMG prepared in 2016 regarding cost control, forecasting, and risk management, and it should report its progress on implementing MGF, KCB, and these KPMG recommendations, both to the PUB at the next GRA and to the Government.

Recommendation #5.2: For any future major capital project that Manitoba Hydro proposes to construct, it should be required to demonstrate available capacity for project management through internal and/or external resources. This is a matter of execution risk that must be dealt with and considered during the mandatory public review of the project. This review should focus on the specific individuals and processes proposed to be used for the project in question, not Manitoba Hydro's institutional expertise that the project team may or may not benefit from. For areas where Manitoba Hydro lacks internal expertise, it should retain the services of external parties through a model that shares risks for that aspect of project execution with the third party (such as a P3 model, as discussed in Recommendation #2.2).

Recommendation #5.3: Given the PUB's jurisdiction to consider Manitoba Hydro's capital expenditures as a factor in setting rates and to ensure that rates reflect prudent expenditures, the PUB should carefully scrutinize the costs incurred by Manitoba Hydro with respect to capital projects like Keeyask. Any costs incurred by Manitoba Hydro that are not prudent should be excluded in the PUB's calculation of rates and thus borne by Manitoba Hydro and its shareholder (the Government of Manitoba), rather than ratepayers. This would provide an incentive to Manitoba Hydro and the Government of Manitoba to provide greater oversight of any future major capital projects and implement processes to mitigate cost overruns and avoid incurring imprudent costs.

Recommendation #5.4: To supplement Recommendations #5.1 and #5.2 for Manitoba to use external expertise for any future high-value capital projects (including potential P3 arrangements), Manitoba Hydro should plan its capital development program where possible so that multiple "mega" projects are not constructed simultaneously. This would help avoid capacity issues and improve project execution, which would, in turn, improve the financial health of Manitoba Hydro (and the Province). To the extent that any major projects are carried out by Manitoba Hydro in the future, dedicated senior management should be assigned to provide clear lines of responsibility and executive oversight, as noted in Recommendation #4.12.

Recommendation #5.5: The MHEB must be provided with accurate, timely, and complete information on all material aspects of project development – including regarding project management risks and cost overruns – so that it can properly discharge its duties and make good decisions. It is the MHEB that is ultimately accountable (to the Government and, by extension, to Manitobans) for Manitoba Hydro's capital program and the consequences of any cost overruns or other failures. The Government relies on the MHEB for its analysis.

Recommendation #5.6: The Commissioner believes that the relationship between the Government and Manitoba Hydro should be between the Chair of the MHEB, the CEO of Manitoba Hydro and the Minister Responsible for Manitoba Hydro. There should be regular briefings from the Chair of the MHEB and the CEO of Manitoba Hydro to the Minister Responsible for Manitoba Hydro, in addition to any project-specific briefing recommended in this report. The Minister Responsible for Manitoba Hydro should, in turn, be accountable for decisions by Manitoba Hydro, including to the Legislature through plenary proceedings and standing committees.

Recommendation #5.7: The Chair of the MHEB must ensure that the MHEB has the capacity to evaluate management proposals and hold management to account, as is its duty. To the extent that the MHEB does not have this capacity through its members, the Chair of the MHEB should ensure that the MHEB retains external expertise (e.g., in the form of external reviews and technical advisors) to ensure that it is properly discharging its oversight function.

If a regular reporting relationship is in place between Manitoba Hydro and the Government, as discussed in Recommendation #5.8, there is no need to have any MLAs appointed to the MHEB.

Recommendation #5.8: Government has an important role to play in being aware of, and actively monitor, major capital projects like Keeyask and Bipole III. Government is responsible to Manitobans and should fulfill that responsibility by expecting regular reports and asking questions about project progress and holding Crown corporations like Manitoba Hydro to account through the responsible Minister. The Minister should be held responsible for the level of knowledge of the Government and, in terms of project risk, the Minister should report on activities to do with project variance and risks to Cabinet. To do so, the Minister must be aware of emerging risks and question the project managers regarding details of their mitigation plan(s) and hold them to account for their performance against the approved plan(s).

Recommendation #6.1: MHEB is the body to whom Manitoba Hydro's management is responsible. To improve the accountability and therefore the performance of management, the MHEB must:

1. Expect more accurate demand forecasts or identify the uncertainty and mitigate it, either by delaying decisions or ensuring that sufficient risk reserves are in place.
2. Expect more accurate cost estimates. Wuskwatim, Bipole III, and Keeyask have been significantly over the original control budgets. Simply creating another increased control budget without accountability is not careful management by the MHEB.
3. Management must be held accountable for the accuracy of information presented to the MHEB for decision.

Glossary of Terms

All Gas: An alternative to Bipole III that was considered by Manitoba Hydro, which would have involved the addition of 2000 MW of natural gas-fired generation located in southern Manitoba to enhance the reliability of Manitoba's electric system. This alternative was examined in the EIS presented to the CEC by Manitoba Hydro and in the September 2016 report from BCG.

Alternating Current (AC): Electric current that reverses its direction of flow at regular intervals. This occurs 60 times each second and is referred to as a frequency of 60 cycle (Hertz). All utilities in North America use 60 Hertz.

Base Load: The basic demand for electricity that is expected during all times.

BBE: A consortium of Bechtel Canada Co., Barnard Construction of Canada Ltd., and EllisDon Civil Ltd. This consortium was the successful bidder and general contractor for the Keeyask project.

Bill 35: A Government Bill, titled *The Public Utilities Ratepayer Protection and Regulatory Reform Act*, that received first reading in the Legislative Assembly of Manitoba on October 14, 2020, during the third session of the 42nd Legislature. As of the date this report was finalized, Bill 35 had not yet received second reading. In substance, Bill 35 is identical to Bill 44, which received first reading on March 19, 2020 during the second session of the 42nd Legislature, but did not receive second reading before the end of that session.

Bipole: An electrical power transmission line, within a high-voltage direct current (HVDC) system, having two direct current conductors in opposite polarity. Manitoba Hydro implemented a high-voltage direct current system to economically and efficiently transmit power generated by hydroelectric stations on the Lower Nelson River to southern Manitoba.

Bipole I: An 895-kilometre HVDC transmission line that connects the Radisson converter station north of Gillam, which first transmitted energy in March 1971, with the Dorsey converter station in Rosser in the south, which received its first transmission from Bipole I in June 1972. Before Bipole III's completion in 2018, over 70% of the electricity generated in Manitoba was delivered to customers through Bipole I and Bipole II.

Bipole II: A 937-kilometre HVDC transmission line that connects the Henday converter storage north of Gillam, which first transmitted energy in October 1978, with the Dorsey converter station in Rosser in the south. Bipole II runs alongside Bipole I for much of its route. Before Bipole III's completion in 2018, over 70% of the electricity generated in Manitoba was delivered to customers through Bipole I and Bipole II.

Bipole III: A project built by Manitoba Hydro that includes a 1400-kilometre HVDC transmission line, the new Keewatinohk converter station northwest of Gillam, and the Riel converter station just east of Winnipeg, which that transmission line connects. Bipole III provides 2000 MW of additional capacity and an HVDC system that is physically separate from Bipole I and Bipole II.

Bipole III Coalition: An organization on behalf of which presentations were delivered to the PUB during the NFAT and the 2017/18 GRA.

Bipole III East: A shorter, alternative route that was initially proposed for the Bipole III transmission line that would have been located east of Lake Winnipeg. The route for Bipole III East would have been approximately half the length of the route for Bipole III West – the route that was ultimately approved and used to construct Bipole III. This alternative route was examined in the September 2016 report from BCG.

Bipole III West: The 1400-kilometre route of the Bipole III transmission line on the west side of the Province that was ultimately approved and used to construct Bipole III. This route is approximately twice the length of Bipole III East.

Boston Consulting Group (BCG): A consultant that was retained by the Manitoba Hydro-Electric Board in 2016 to evaluate the prudency and risk associated with Manitoba Hydro's investments to build Bipole III, Keeyask, the Manitoba Minnesota Transmission Project, and the Great North Transmission Line. BCG delivered its report in September 2016.

Capacity: The amount of power that a piece of equipment, or a group of pieces of equipment acting together, can generate or transmit. For example, a transmission line may have a transfer capacity of 750 megawatts, or a generating station may have a capacity to produce 1200 megawatts.

Capital Expenditure Forecast (CEF): A projection of the capital expenditures needed annually for new and replacement equipment and facilities to meet the electricity requirements in Manitoba and firm export sale commitments outside the Province.

Capital Project Justification (CPJ): A framework used by Manitoba Hydro to summarize technical, economic, and financial information for a project that is being proposed or revised for inclusion in Manitoba Hydro's capital program. Once the need for a capital project is identified, Manitoba Hydro prepares a CPJ. Information relative to each project, such as a business case, risk assessment, resourcing requirements, and other pertinent details, are presented in the CPJ. Proposed capital expenditure projects are reviewed and approved by Manitoba Hydro's management and executive prior to their inclusion in Manitoba Hydro's CEF.

Carbon Price: A tax or surcharge levied by a government on electricity generated from sources that emit carbon dioxide (CO_2). The carbon price is specified in dollars per tonne of CO_2. Different generating stations produce different amounts of carbon dioxide per MWh of electricity output, with coal producing the greatest amount of CO_2 and combined cycle gas turbines producing about half of the emissions of coal per MWh.

Clean Energy Strategy: An energy policy document released by the Government of Manitoba in December 2012. It outlines proposed goals and actions in five areas: (1) building a new Manitoba Hydro; (2) leading Canada in energy efficiency; (3) keeping rates low; (4) growing renewable alternatives; and (5) freedom from fossil fuels.

Clean Environment Commission (CEC): Manitoba's environmental regulatory tribunal.

Combined Cycle Gas Turbine (CCGT): The combination of a gas turbine and a steam turbine in an electric generating plant. The waste heat from the gas turbine provides the heat energy for the steam turbine.

Commission: The Economic Review of Bipole III & Keeyask Commission that inquired into Manitoba Hydro's development of Keeyask and Bipole III under the direction of the Commissioner and his predecessor, Gordon Campbell.

Commissioner: Brad Wall, who was appointed as a commissioner to inquire into Manitoba Hydro's development of Keeyask and Bipole III pursuant to Order in Council (O.C.) 333/2019, which amended O.C. 301/2018.

Conawapa: A potential hydroelectric generating station on the Nelson River, most recently proposed by Manitoba Hydro as part of its Preferred Development Plan in 2013 and reviewed at the NFAT in 2014. The NFAT Panel recommended that Manitoba Hydro cease its development and this recommendation was accepted by the provincial Government.

Control Budget: A formal budget for a capital project developed by the project team and approved by management.

Converter Station: A high-voltage direct current (HVDC) converter station is a specialized type of substation which forms the terminal equipment for a HVDC transmission line. Converter station equipment converts alternating current to direct current, or the reverse. Manitoba Hydro currently operates, or has in construction, three northern converter stations (Henday, Radisson, and Keewatinohk) to convert alternating current (AC) collected from nearby generating stations to direct current (DC) power for transmission. As well, Manitoba Hydro operates, or has in construction, two southern converter stations (Dorsey and Riel) to convert DC to AC for downstream customer transmission and distribution.

Cost Reimbursable Contract: A contract pricing structure in which the contractor is paid for its costs for materials and direct labour, plus profit and general administration and overheads. In a cost reimbursable contract, the project owner (Manitoba Hydro) is at risk for quantities, productivity, and inefficiency of the contractor.

Cumulative Present Value (CPV): A metric that examines how beneficial a development plan is compared to a base case from the start of a study period to a certain point in time during the period. The cumulative present value is the net present value of all costs and revenues at a given time. Such an analysis provides an understanding of the year when a plan breaks even on a present value basis when compared to the base case and other development plans.

Debt Guarantee Fee: In the case of Manitoba Hydro, a 1.0% fee that is paid to the Government of Manitoba based on a percentage of Manitoba Hydro's outstanding debt.

Debt/Equity Ratio: A measure of the portion of assets that are financed by Manitoba Hydro's internally generated funds, rather than debt. This measurement evaluates the relationship of debt (long-term debt, sinking fund investment, short-term debt, and short-term investments) to equity (comprised of retained earnings, customer contributions, accumulated other comprehensive income, and non-controlling interest) through a comparison of Manitoba Hydro's net debt to total capital. The debt/equity ratio identifies the capital structure of Manitoba Hydro. In recent years, a debt/equity ratio of 75/25 has been used as a long-term financial target for Manitoba Hydro.

Demand Side Management (DSM): A targeted reduction in the demand for electricity through energy efficiency measures and updated codes and standards. DSM can reduce the requirement for new electricity generation and serve as a source of meeting demand in the same manner as new generation.

Dependable Energy: The energy that a hydroelectric generating station or electric system reliant on hydroelectric generation can produce under the lowest water flow conditions. Manitoba Hydro's total dependable energy is comprised of dependable energy from hydro generation, thermal generation, wind generation, and imports.

Development Plan: A plan formulated by Manitoba Hydro and presented during the NFAT using screened-in resource options (i.e., DSM, hydro, wind, natural gas, and imports), considering economic, financial, environmental, socio-economic/provincial characteristics, and strategic business opportunities. Each development plan must have been able to meet Manitoba Hydro's expected domestic load and existing firm export commitments. During the NFAT, various development plans were comparatively evaluated, including the preferred development plan and alternative development plans.

Discount Rate: A percentage rate by which a future revenue flow is discounted to derive the Net Present Value (NPV) of that flow of money.

Distributed Generation: Electricity generation that is located closer to load centres or downstream of the customer's meter. Distributed generation is usually comprised of smaller scale generating facilities.

Distribution: Utility assets used to distribute lower voltage electricity to individual customers. These assets include distribution lines operating at less than 30 kV along with associated low voltage portions of substations, low voltage transformers, and metering.

Domestic Demand: Domestic load (e.g., in Manitoba) net of reductions resulting from DSM.

Dorsey Converter Station (Dorsey): A converter station in Rosser that is the southern end point for Bipole I and Bipole II. Over 70 % of the electricity produced in Manitoba is transmitted through Dorsey. It received its first transmission from Bipole I in June 1972.

EBITDA: A cash flow financial metric of an interest coverage ratio of earnings before interest, taxes, depreciation, and amortization.

Economic Uncertainty Analysis: An analysis provided as part of Manitoba Hydro's economic evaluation of development plans during the NFAT. This branch of the analysis included a probabilistic analysis, which examined the range of uncertainty around energy prices, the discount rate, and capital costs.

Elenchus Research Associates Inc. (Elenchus): An independent expert consultant that was retained by the PUB during the NFAT to assist in the PUB's consideration of load forecasting, DSM, and energy efficiency.

Energy: A quantity of power consumed over a period of time. Energy is expressed in kilowatt-hours (kWh), megawatt-hours (MWh), or gigawatt-hours (GWh). A 100-watt incandescent light bulb burning for 10 hours consumes one kWh (0.1 kW x 10 hrs).

Environmental Impact Statement (EIS): A document prepared by a proponent to describe the effects of a proposed project on the environment. Manitoba Hydro filed environmental impact statements for Bipole III and Keeyask with the CEC, which formed the bases of the CEC's hearings into each project.

Environmental Non-Governmental Organization (ENGO): A non-governmental organization with a particular focus on environmental issues.

Expected NPV: The probability weighted NPV of a development plan calculated from the low, reference, and high estimates of energy prices, capital costs, and economic indicators/discount rates. Expected value is used in the economic analysis.

Firm Export: The guaranteed sale of a contracted amount of energy and/or capacity to utilities or customers located outside of Manitoba.

Firm Power: Capacity and energy that must be supplied to meet domestic demand or under certain export contracts. Firm power is guaranteed to be available when specified and can only be interrupted in emergencies or when the reliability of the power system is threatened.

Fixed Price Contract: A contract pricing structure in which a contractor is paid a fixed price regardless of the costs it incurs or the duration of the project. In a fixed price (i.e., lump sum) contract, the contractor is at risk for quantities and productivity.

Full-Time Equivalent (FTE): A unit of measurement equal to one employee working a full-time job over a specified period of time.

General Civil Contract (GCC): The primary contract that Manitoba Hydro entered into for construction of the Keeyask generating station. The GCC encompasses work related to river management, earthworks to build dams and dykes, concrete structures, and electrical and mechanical work within the powerhouse and spillway structures.

General Rate Application (GRA): A PUB process to review Manitoba Hydro's proposed changes to electrical or gas rates and their impacts on various customer groups.

Generation: Utility assets used to generate electricity. Manitoba Hydro considers all generating facilities, northern collector transmission lines, and HVDC facilities (such as Bipoles and converter stations) as generation in its cost of service studies.

Gigawatt-Hour (GWh): A unit of electrical energy. A GWh is the amount of electrical energy produced by one gigawatt of power applied over one hour of time, or 1000 MW over one hour. A GWh is equivalent to 1,000,000 kilowatt hours (kWh) or 1000 megawatt hours (MWh).

Great Northern Transmission Line: A 750 MW, 500 kV AC transmission line built by Minnesota Power in Minnesota. In the north, it joins the Manitoba-Minnesota Transmission Project. In the south, it terminates near Duluth, Minnesota.

Green Action Centre: One of the five interveners in the NFAT.

Greenhouse Gases (GHG): Gases that contribute to climate change because they contribute to the greenhouse effect of the Earth's atmosphere by trapping thermal radiation from the sun. For electricity generation, the most common greenhouse gas – and the one of greatest concern – is carbon dioxide (CO_2), which is a product of the combustion of fossil fuels such as coal and natural gas.

Grid Parity: The point where distributed generation technologies such as solar photovoltaics can generate electricity for the same cost as buying electricity from the utility using its distribution grid.

Gross Firm Energy: The total annual non-curtailable demand for energy in Manitoba.

High-Voltage Direct Current (HVDC): An electric power transmission system that uses direct current for the bulk transmission of electrical power, in contrast with the more common alternating current (AC) systems. HVDC transmission is point-to-point, as opposed to the interlaced networks that are possible with AC systems. For long-distance transmission, HVDC systems may be less expensive and suffer lower electrical losses.

Import + gas: An alternative to Bipole III that was considered by Manitoba Hydro, which would have involved the addition of 1500 MW of new imports from the U.S. and 500 MW of new natural gas-fired generation located in southern Manitoba to enhance the reliability of Manitoba's electric system. This alternative was examined in the EIS presented to the CEC by Manitoba Hydro and in the September 2016 report from BCG.

In-Service Date: The date on which a unit or facility is complete and ready for service.

Independent Expert Consultant (IEC): Independent third-party experts retained by the NFAT Panel for purposes of the NFAT Review. IECs were represented by independent legal counsel and subject to cross-examination of their reports and testimony.

Integrated Financial Forecast (IFF): Projections of Manitoba Hydro's financial results and position over a multiyear forecast period, typically 20 years. The Integrated Financial Forecast serves as the primary forecast to determine the need for rate increases that are necessary for Manitoba Hydro to maintain a reasonable financial position and progress towards attaining and maintaining its financial targets.

Integrated Resource Planning (IRP): A method of utility resource planning that determines analytically what resource is in the best interests of consumers by examining a full spectrum of possible supply-side and demand-side options (e.g., DSM) and measuring them against a collective set of objectives and criteria. This contrasts with traditional methods of utility resource planning, which emphasize supply-side options such as building new generation, transmission, and distribution facilities.

Interconnection: A power line that interconnects one electrical utility's power system with another. An interconnection facilitates the export and import of power.

Interlake: The region in Manitoba that lies between Lake Winnipeg in the east, and Lake Winnipegosis and Lake Manitoba in the west.

Internal Rate of Return (IRR): A metric typically used to evaluate investments. It is the interest rate at which the net present value of the costs associated with an investment (e.g., a development plan) equals the net present value of its benefits. It calculates the average annual return earned over the length of the study period. Another way of describing the internal rate of return is the discount rate that brings the net present value to zero.

Joint Keeyask Development Agreement (JKDA): The agreement between the Manitoba Hydro-Electric Board and the Keeyask Cree Nations that governs how Keeyask is being developed and sets out understandings related to potential income opportunities, training, employment, business opportunities, and other related matters.

Keeyask Cree Nations (KCN): A term used to collectively refer to the four First Nations that are parties to the Joint Keeyask Development Agreement and part of the Keeyask Hydropower Limited Partnership. These four First Nations are Tataskweyak, War Lake, Fox Lake, and York Factory.

Keeyask Generating Station (Keeyask): Manitoba Hydro's newest and fourth largest hydroelectric generating station currently under construction on the Nelson River. It will have a capacity of 695 MW and produce annual dependable energy of 3000 GWh.

Keeyask Hydropower Limited Partnership (KHLP): The partnership between Manitoba Hydro and the Keeyask Cree Nations through which Keeyask is being developed, in accordance with the terms of the Joint Keeyask Development Agreement. Manitoba Hydro provides the administrative and management services for the partnership and will own at least 75% of the equity of the partnership, while the Keeyask Cree Nations together have the right to own up to 25%. The partnership has contracted the planning, construction, and operation of Keeyask to Manitoba Hydro and will sell all the power produced at Keeyask to Manitoba Hydro.

Keeyask Infrastructure Project (KIP): A project that involved the construction of preparatory support infrastructure required to construct the Keeyask Generating Station, including the construction of roads and work camps. Approved and begun in early 2012, this infrastructure work was separately licensed and approved in advance of the Keeyask Generating Station. It was completed in July 2014.

Kilovolt (kV): An amount of electromotive force equivalent to 1000 volts. A volt is representative of the difference of potential that would drive one ampere of current against one ohm of resistance. It is roughly analogous to the pressure in a water pipe.

Kilowatt (kW): The unit of electrical power equivalent to 1000 watts (W). A watt is unit of measurement for electrical power, corresponding to the power in an electric circuit in which the potential difference is one volt and the current is one ampere.

Kilowatt-Hour (kWh): A unit by which electrical energy is measured. A kilowatt-hour is a unit of energy equivalent to one kilowatt (1000 watts) of power applied over one hour of time. For example, ten 100 W light bulbs switched on for one hour would use one kilowatt-hour. The electrical energy used in homes and small businesses is usually measured in kilowatt-hours.

Klohn Crippen Berger (KCB): An independent consultant with expertise in hydroelectric generating station design and engineering, who was retained by the PUB during the 2017/18 GRA to assist MGF with the review of Keeyask.

La Capra Associates Inc. (LCA): An independent expert consultant that was retained by the PUB during the NFAT to assist in the PUB's consideration of power resource planning, economic evaluation, business case and risk analysis, transmission economics, export contracts, and financial modelling. In 2015, La Capra Associates Inc. was renamed Daymark Energy Advisors. Daymark Energy Advisors was retained by the PUB during the 2017/18 GRA to review and provide an expert opinion on Manitoba Hydro's export price and revenue forecasts and electricity load forecasts, among other things.

Limestone Generating Station (Limestone): The fifth generating station built on the Nelson River by Manitoba Hydro. It is the largest generating station in the Province, with a capacity of 1350 MW. Its construction was completed in 1992 at a cost of $1.43 billion.

Line-Commutated Converter (LCC): A common converter technology that was used in the Bipole III project and Manitoba Hydro's pre-existing HVDC system.

Line Loss: While transmitting electricity from generating stations to the end users, electricity passes through a complex transmission and distribution network, consisting of transformers, switches, and conductors. As it passes through the system, some of the energy is consumed by various system components or is dissipated due to the physical properties of the equipment. As a result, the total amount of electric energy measured at customer meters is always less than the total amount of electric energy measured at generating stations. The difference between the two is known as line loss.

Liquefied Natural Gas (LNG): Natural gas that has been cooled to a liquid state for shipping and storage. In recent years, numerous LNG projects have been proposed for the export of natural gas from Canada.

Load: The total amount of electricity demand in a jurisdiction, such as Manitoba.

Load Forecast: A forecast of load over a specified period of time in the future. Manitoba Hydro prepares a 20-year load forecast on an annual basis that projects demand in several customers classes, including residential, general service commercial, general service industrial, and top consumers. Manitoba Hydro's load forecast is used for several purposes, including forecasting revenue for rate-setting and resource planning.

Lump Sum Contract: See Fixed Price Contract.

Major Projects Executive Committee (MPEC): A committee established by Manitoba Hydro in 2016 which comprised Manitoba Hydro's President and CEO as well as five vice-presidents with accountability over the areas of the company responsible for the execution of major capital projects. The MPEC was established to provide oversight, direction, and strategic decision making with respect to Keeyask, Bipole III, the MMTP, and the Great Northern Transmission Line.

Management Reserve: A cost or time reserve that is used to manage unidentified risks.

Manitoba Hydro (MH): A Manitoba Crown corporation governed through the Manitoba Hydro-Electric Board and continued by *The Manitoba Hydro Act*. Its statutory mandate 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. In addition, it has a mandate to: (a) 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) market and supply power to persons outside the Province on terms and conditions acceptable to the Manitoba Hydro-Electric Board.

Manitoba Hydro-Electric Board (MHEB): The board provided for in section 5 of *The Manitoba Hydro Act*, which is charged with administering the affairs of Manitoba Hydro and is to consist of 6 to 10 members appointed by the Lieutenant Governor in Council. Members of the MHEB serve for the term specified in the order in council by which they are appointed. One of the members is designated as the chair and another as the vice-chair.

Manitoba Minnesota Transmission Project (MMTP): A 750 MW, 500 kV AC transmission line built by Manitoba Hydro which entered service on June 1, 2020. It connects Dorsey south of Winnipeg with the Great Northern Transmission Line at the Manitoba-Minnesota border.

Megawatt (MW): The unit of electrical power equivalent to 1,000,000 watts (W).

Megawatt-Hour (MWh): A unit by which electrical energy is measured. One MWh is a unit of energy equivalent to 1,000,000 watts (W) of power applied over one hour of time.

Merchant Plant: A generating station that is primarily designed and built for the export market, rather than the domestic market.

MGF Project Services (MGF): Construction management experts retained by the PUB during the 2017/18 GRA as the project lead to conduct a review of Manitoba Hydro's major capital expenditures, including with respect to Keeyask and Bipole III.

Midcontinent Independent System Operator, Inc. (MISO): A U.S.-based independent, not-for-profit regional transmission organization responsible for maintaining reliable transmission of power in 15 U.S. states and Manitoba.

Minister Responsible for Manitoba Hydro: The member of the Manitoba Cabinet charged with the administration of *The Manitoba Hydro Act*. Currently, the Minister Responsible for Manitoba Hydro is the Minister of Crown Services.

Minnesota Power (MP): An owner and operator of electric generation and transmission facilities in Minnesota that is engaged in the generation, transmission, distribution, and sale of electric energy. Minnesota Power has entered into export contracts with Manitoba Hydro for the purchase of electric power from Manitoba Hydro.

Morrison Park Advisors Inc. (MPA): An independent expert consultant that was retained by the PUB during the NFAT to assist in the PUB's consideration of the commercial evaluation of Manitoba Hydro's preferred development plan. During the 2017/18 GRA, MPA was an expert witness jointly retained by the Consumers Coalition and the Manitoba Industrial Power Users Group and gave evidence regarding Manitoba Hydro's financial plan and targets.

Multiple Account Benefit Cost Analysis (MA-BCA): An analysis conducted by Manitoba Hydro for several development plans during the NFAT, including the preferred development plan, which determined net social benefits of each development plan and how they would be distributed among Manitoba Hydro, ratepayers, the provincial Government, and Manitobans in general.

Need Date: The year in which new generation resources, such as Keeyask or a gas turbine plant, are required due to a shortfall in energy or capacity.

Net Present Value (NPV): The present value of a future revenue and cost stream. NPV is calculated by taking an assumed revenue in each future year and applying a discount rate to account for the time value of money (e.g., 10 years from now, $100 will not have the same value as today). The applicable discount rate is a matter of judgment and was a subject of debate in the NFAT. Frequently in the NFAT, the NPV of development plans was referenced to the NPV of the All-Gas plan (i.e., the All-Gas plan NPV was set to zero and the NPVs of the other plans were adjusted accordingly).

Needs For and Alternatives To (NFAT): The review of Manitoba Hydro's Preferred Development Plan by the PUB, with final recommendations made to the Province of Manitoba as to which development option should proceed, as requested by the Government of Manitoba via Order in Council 128/2013.

NFAT Panel: The members of the PUB who conducted the NFAT and issued a report, as requested by the Government of Manitoba via Order in Council 128/2013.

NFAT Report: The report issued by the NFAT Panel following the NFAT, as requested by the Government of Manitoba via Order in Council 128/2013.

NFAT Terms of Reference: The terms of reference that were attached to Order in Council 128/2013, through which the Government of Manitoba requested the NFAT and in accordance with which the NFAT was to be conducted.

Opportunity Sales: Export sales made from surplus generation, typically hydroelectric generation that is available in most water flow conditions except drought conditions.

P50: A value at which the expected outcomes have a 50% probability of being higher than the value and 50% chance of being lower than the value.

P75: A value at which the expected outcomes have a 25% probability of being higher than the value and 75% chance of being lower than the value.

P80: A value at which the expected outcomes have a 20% probability of being higher than the value and 80% chance of being lower than the value.

P90: A value at which the expected outcomes have a 10% probability of being higher than the value and 90% chance of being lower than the value.

Peak Demand: The instantaneous maximum amount of electricity required by a customer or group of customers.

Peak Load: Instantaneous maximum amount of electricity used. On an annual basis, peak load in MISO occurs during the summer air conditioning season, while peak load in Manitoba occurs during the winter heating season. On a daily basis, peak load varies with the business cycle.

Person-Year: A person-year of employment is the equivalent of one full-time job for one year. The number of hours assigned to a person-year vary. In the Keeyask EIS, one person-year of employment was defined as 3000 hours of work.

Power: The flow of electricity at any given time. Power is expressed in watts (W), kilowatts (kW – 1000 watts) or megawatts (MW – 1,000,000 watts).

Preferred Development Plan (PDP): The development plan that Manitoba Hydro advocated for in its application during the NFAT. It included the following:

- Keeyask, with a planned in-service date of 2019;
- Conawapa, with a planned in-service date of 2026;
- The Manitoba Minnesota Transmission Project, with a planned in-service date of 2020;
- New natural gas-fired generation starting in 2041/42;

- A 250 MW system power sale agreement with Minnesota Power; and
- A 308 MW system power sale agreement with Wisconsin Public Service.

Project Contingency: An amount of funds added to the base cost estimate of a project to cover estimate uncertainty and manage identified risks.

Public-Private Partnership (P3): A partnership between government(s) and the private sector to build public infrastructure such as roads, hospitals, or schools, or to deliver services. Unlike traditional procurement, the public sector integrates all parts of a P3 project into one contract.

Public Utilities Board (PUB): An arm's length, provincial, quasi-judicial body established under *The Public Utilities Board Act*. The Lieutenant Governor in Council appoints the PUB's members. One of the PUB's main functions is to set "just and reasonable rates" that utilities such as Manitoba Hydro may collect from ratepayers for electricity and natural gas services. In addition to its general jurisdiction, the PUB may, from time to time, perform additional duties assigned to it, such as those assigned by order of the Lieutenant Governor in Council under section 107(b) of *The Public Utilities Board Act*.

Ratepayers: A customer of a public utility, such as Manitoba Hydro, who pays for that utility service based upon a certain rate. In the case of Manitoba Hydro, the rates that it may collect from ratepayers are set by the PUB.

Reference NPV: The net present value of a development plan based on assumptions associated with the reference scenario presented in Manitoba Hydro's application during the NFAT.

Reliability: The ability of the power system to meet peak load. Part of Manitoba Hydro's statutory mandate is to provide and maintain a reliable power system. The degree of system reliability is typically measured by "loss of load expectation" – the average number of days per year that the load cannot be fully met.

Simple Cycle Gas Turbine (SCGT): A turbine powered by natural gas or fuel oil in an electric generation plant. The waste heat from the gas turbine is exhausted and not utilized.

Solar Photovoltaic Generation: The conversion of sunlight directly into electricity by incidence of sunlight on a semiconductor surface, also known as a solar panel. The amount of electricity generated is proportional to the size of the solar panel and can range from roof-top units that generate electricity for a residential home to utility-scale arrays of solar panels that produce megawatts of electricity.

Stage Gate: A project management tool whereby a project does not move from one pre-defined stage to the next (i.e., receive approval to go to the next pre-defined stage) until a set of criteria is satisfied. The criteria may be technical, financial, commercial, or other.

Sunk Cost: Money that has already been spent and cannot be recovered. Sunk costs are excluded from future business decisions because the cost will remain the same regardless of the outcome of a decision.

Surplus Energy: Energy not needed to meet Manitoba's domestic demand and which Manitoba Hydro is not contractually required to export.

Target Price Contract: A contract pricing structure in which the contractor's profit erodes if the target price is exceeded and the contractor's profit increases if the actual cost is less than the target price. This structure is intended to incent the contractor to perform well.

Terms of Reference: The terms of reference that were attached to the order in council through which the Government of Manitoba appointed the Commissioner and in accordance with which the Commission inquired into Manitoba Hydro's development of Keeyask and Bipole III.

Tie-line: A term used to refer to the Manitoba Minnesota Transmission Project and the Great Northern Transmission Line projects, collectively.

Top Consumers: The largest industrial consumers of electricity in Manitoba (i.e., the top energy consuming operations). In Manitoba Hydro's 2018 electric load forecast, there were 10 distinct companies that counted as 26 top consumers in the mining and forestry, chemical treatment, and petrol/oil/natural gas sectors, and accounted for a combined 25% of all general consumer sales.

Total Demand: The sum of domestic demand and firm export commitments.

Transmission: Utility assets used to transmit electricity between load centres. In its cost of service studies, Manitoba Hydro considers all transmission lines and high-voltage portions of substations operating in excess of 100 kV as transmission. With respect to capital expenditures, transmission refers to assets operating in excess of 33 kV.

Treasury Board: A sub-committee of Cabinet responsible for the overall fiscal management and reporting of the Government of Manitoba and the establishment of policies required for the effective management of public funds to meet government objectives.

Treasury Board Secretariat: An independent secretariat that provides financial and analytical support and strategic management advice to the Minister of Finance and Treasury Board. The Secretariat is headed by a deputy minister who acts as Secretary to the Treasury Board. Its major functions include monitoring, analyzing, and reporting on the financial position of the Province, and planning and coordinating the review and preparation of the annual estimate, and participating in the development of the annual budget.

UNESCO World Heritage Site Designation: The designation for places on Earth that are considered by the United Nations Educational, Scientific and Cultural Organization (UNESCO) to be of outstanding universal value to humanity and as such, are inscribed on its World Heritage List in hopes of protecting them for future generations.

Unit Price Contract: A contract pricing structure in which a contractor is paid a pre-defined unit rate (or rate per quantity) multiplied by the quantity of work. In a unit price contract, the contractor is at risk for productivity and the project owner (Manitoba Hydro) is at risk for variation in quantity from the initial estimates provided by the owner.

Water Rentals: Fees paid by Manitoba Hydro to the provincial Government based on the amount of electricity produced from hydroelectric generation.

Whitfield Russell Associates (WRA): A consultant engaged by the Manitoba Metis Federation (MMF), an intervener during the NFAT.

Wisconsin Public Service (WPS): An owner and operator of electric generation and transmission facilities in Wisconsin that is engaged in the generation, transmission, distribution, and sale of electric energy. Wisconsin entered into export contracts with Manitoba Hydro for the purchase of electric power from Manitoba Hydro.

Wuskwatim Generating Station (Wuskwatim): The most recent hydroelectric generating station completed by Manitoba Hydro, which is located on the Burntwood River. It has a capacity of 210 MW and was completed in 2012 at a cost of $1.3 billion.

Voltage: The electric potential between two points in an electric connection, expressed in volts (V) or kilovolts (kV). A North American electrical outlet operates at 120 volts. High-voltage transmission usually operates at either 230 kV or 500 kV.

List of Participants

The list of those who participated in the Commission's process through interviews and/or written submissions is as follows:

- Al Snyder
- Alec W.G. Clark
- Alistair Fogg
- Anna Rothney
- Blain Poff
- Bob Brennan
- Bob Peters
- Brady Ryall
- Bruce Bremner
- Byron Williams
- Chief Betsy Kennedy
- Chief Billy Beardy
- Chief Leroy Constant
- Chief Walter Spence
- Cliff Culen
- Consumers' Association of Canada (Man.)
- Councilor Nathan Neckoway
- Craig Saunders
- Darren Christie
- Dave Cormie
- Don Delisle
- Doug Ewing
- Ed Tymofichuk
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- Gerald Neufeld
- Gloria Desourcy
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- Greg McNeill
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- Harold R. Holloway
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- Sandy Bauerlein
- Sanford Riley
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- Scott Thomson
- Shane Mailey
- Stewart Pierce
- Terry Miles
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- Victor Spence
- Vince Warden
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