PRE-FILED TESTIMONY OF

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IN REGARD TO THE MANITOBA HYDRO NEEDS FOR AND ALTERNATIVES TO ("NFAT") BUSINESS CASE SUBMISSION

Submitted to:

The Manitoba Public Utilities Board

on behalf of

Manitoba Industrial Power Users Group

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TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1.0 INTRODUCTION AND SUMMARY OF CONCLUSIONS

This testimony has been prepared for the Manitoba Industrial Power Users Group (“MIPUG”) by InterGroup Consultants Ltd. (“InterGroup”) under the direction of Mr. P. Bowman. MIPUG’s current membership and concerns are outlined in Section 2.0. The qualifications of Mr. Bowman are provided in Attachment A.

InterGroup has been asked to identify and evaluate issues arising from Manitoba Hydro’s (“Hydro” or “MH”) Needs For and Alternatives To filing (“NFAT” or “filing”) in respect of proposed power developments and in particular Hydro’s Preferred Development Plan (“PDP” or “Plan 14”). The scope of issues that are of interest to industrial customers that are included in the approved scope for intervention in the NFAT by PUB Order 67/13 are as follows[1]:

- Impact on domestic rates, including long term impacts;
- Risks to domestic customers through Manitoba Hydro’s investment in subsidiaries, export ventures and new Programs;
- Alternatives to Manitoba Hydro’s Preferred Development Plan including demand side management programs; and
- Risks including long term financial and economic risks and the financial liability of Manitoba Hydro.

Pursuant to Board Order 67/13, the scope of MIPUG’s intervention is also to reflect two aspects of coordination:

1) **Consultation and coordination with the broader business community in Manitoba.** Aspects of this filing reflect InterGroup’s assessment of issues that were identified by the broader business community for review, most notably in relation to alternatives that minimize near-term spending commitments and associated debt levels.

2) **Coordination with other intervenors to minimize duplication.** InterGroup has focused its efforts towards coordinating with the work of Mr. Bill Harper on behalf of the Consumer’s Association of Canada. While both parties have identified core issues with Hydro’s analysis in the NFAT Chapter 9 and 10 (Economic Evaluations – Reference Scenario & Economic Uncertainty Analysis – Probabilistic Analysis and Sensitivities), InterGroup has focused on addressing these

[1] Order 67/13; Section 3.9.2 Board Findings, page 30-31 (June 11, 2013).

issues by relying on the Chapter 11 results (Financial Evaluation of Development Plans), while Mr. Harper has sought in a complementary way to address the issues with Hydro's Chapter 9 by a revised economic analysis.

The InterGroup review is rooted in normal utility planning and regulatory review principles appropriate for Canadian Crown-owned electric utilities. In preparing this testimony, the following information has been reviewed, focusing on the approved MIPUG scope of intervention:

- The Hydro NFAT, including appendices.
- All Hydro responses to the MIPUG Information Requests ("IR"s) provided as of January 28, 2014.
- A selection of Hydro responses to the IRs of other intervenors, the Board's Independent Expert Consultants (IECs) and the PUB.
- An initial review of relevant portions of the reports of the IEC reports (other than La Capra and Morrison Park Advisors which were delivered at a later date).
- To a limited extent, Hydro's evidence in previous General Rate Application ("GRA") proceedings, including the 2012-2014 GRA, as they relate to the current proceeding.
- Materials considered Commercially Sensitive Information ("CSI") were not available to be reviewed. This includes the specific values used in export contracts, specific text of export contract agreements, and other materials of a commercially sensitive nature.

To the extent conclusions in this submission are affected or altered by the submissions of additional Hydro IRs or submissions of the IECs, it may be necessary to supplement this testimony at a later date, as may be permitted within the PUB's process.

The evidence is presented in the following sections:

- Section 2 provides background on the InterGroup assignment, including the main context of the clients (MIPUG), and the main principles for regulation of Manitoba Hydro that were relied upon in this review.
- Section 3 provides an overview of Hydro's submission, focusing on matters of particular interest and relevance.
- Section 4 provides conclusions regarding the economic and financial analyses.
- Appendix A includes the Curriculum Vitae of Patrick Bowman.

- Appendix B is a critique of the economic analysis provided by Manitoba Hydro.
- Appendix C provides an overview of the review completed by InterGroup on the financial analysis as it relates to domestic ratepayers and other parties.
- Appendix D evaluates the load forecast done by Manitoba Hydro as it relates to the need criteria of future resource planning and potential costs to ratepayers.

1.1 SUMMARY OF INTERGROUP CONCLUSIONS AND RECOMMENDATIONS

InterGroup's conclusions reflect the review conducted to date, prior to upcoming detailed examination of the material at the NFAT hearings. The conclusions are preliminary – further review and examination may lead to modifications. The conclusions below reflect InterGroup's work and may not necessarily reflect the MIPUG group's final positions in respect of the NFAT, following the further exchange of information occurring throughout the hearing process.

This report covers ten conclusions and recommendations. At its core, the evidence focuses on the inherent benefits of being an increasingly interconnected utility, in light of challenges that this vision poses for costs and affordability, including to ratepayers. A key initial question relates directly to this vision, and the distribution of risks and benefits that arises.

The main InterGroup conclusions and recommendations are as follows:

1) Focus on key decisions that need to be made today.
2) Recognize that despite the Plan selected, it is not possible to avoid major risks.
3) "Pathways" are more important than "Plans".
4) There are two possible competing visions – one based on Need and one based on Opportunity - both of which are valid. A possible optimized variant of Plan 1 (All Gas) focused on Need could be a reasonable outcome of the NFAT. Hydro has not yet provided a full scenario to assess this option.
5) Given the information available, an Opportunity-Based vision (advance Keeyask, take up Minnesota Power ("MP") export deal, build new transmission to US) is likely better than a Need-Based vision utilizing Plan 1 (All Gas).
6) Past experience with hydraulic generation and interconnections suggest added benefits from large infrastructure that should not be ignored.

7) The 750 MW transmission option (Pathway #4) should likely be pursued. Part of the rationale is based on future adaptation and optionality, which is not fully explored in Hydro's materials.

8) Evidence does not yet support Conawapa as being in ratepayer interests. The project does show massive benefits to other stakeholders, particularly the provincial Government. The option for Conawapa for 2026 should continue to be protected, while minimizing the ongoing cost commitment. If conditions do not improve, Conawapa should not proceed. If a rebalanced relationship with the province can be secured, there may be ways for Conawapa to be beneficial for ratepayers even if market conditions do not improve.

9) Other planning activities and decisions should be continued or expanded, such as pursuing all economic DSM and customer self-generation, etc. These actions should occur starting in the near-term, regardless as to Pathway selected.

10) There are aspects of the NFAT that are instructive with respect to Hydro's normal rate reviews before the PUB. These items should be addressed in future GRAs.

Each of these items is addressed below in additional detail.

1) Focus on key decisions that need to be made today

The Board must provide recommendations regarding a set of near-term decisions regarding:

a. Whether to take up the Minnesota Power (MP) export agreement (including its requirement for Keeyask for 2019 which requires construction contract awards in the near term) [Whether to proceed with Pathways #1/2 or with Pathways #3/4/5]; and

b. If yes, whether to build the required new line at 750 MW or 250 MW [Whether to proceed with Pathway #3 versus Pathways #4/5].

All other decisions appear to be subsidiary to this immediate requirement. This is because all other aspects of the NFAT have longer and/or more flexible time horizons until commitment is required and/or are much less costly. The above two decisions, however, are not flexible to even short delays or future change.

2) Recognize that despite the Plan selected, it is not possible to avoid major risks.

In an economic sense, risk encompasses not only actual costs incurred that could have been avoided, it also includes foregone opportunities that were not taken. As such, the present NFAT represents unavoidable economic risk.

For industrial customers, the next 20 years indicates higher than inflationary rate increases under all scenarios, which are exacerbated by the NFAT PDP. Over the next 20 years, industrial customers alone are likely to either pay $400 million to amortize the planning costs spent by Manitoba Hydro up until June 2014 (if the projects do not go ahead), or as much as $800 million to secure the full PDP. Financial benefits from the developments only occur after this 20 year horizon, which is longer than is usually seen for hydro generation proposals.

3) "Pathways" are more important than "Plans"

Hydro has provided 15 "Plans" which generally fit into one of 5 "Pathways". The choice of a particular Plan will be a factor in the future level of rates in Manitoba, but not as large a factor as how that plan adapts to future conditions, such as interest rates, export prices, and even government charges. For this reason, selection of the best Plan is not the largest imperative at this time. Selection of the initial Pathway however (per Hydro's Executive Summary Figure 5)[2] is fundamental, as future changes between pathways are generally not possible.

a. Of note, Hydro's Pathway #5 (which includes Plan 14 (PDP)) is at present not a viable option. As of this date there is no apparent agreement with WPS for the 300 MW sale agreement and Hydro's evidence is that even though discussions are underway with respect to this sale, it would not have some of the beneficial characteristics represented by Pathway #5, notably the WPS investment in transmission ownership. For this reason, Pathway #5 can at best be considered representative of a possible risk scenario/upside of Pathway #4.

4) There are two possible competing visions – one based on Need and one based on Opportunity - both of which are valid. A possible optimized variant of Plan 1 (All Gas) focused on Need could be a reasonable outcome of the NFAT. Hydro has not yet provided a full scenario to assess this option.

A critical initial decision relates to the present vision for the power system and province. In contrast to Hydro's conclusions, an optimized version of Plan 1 (All Gas, with supplemental actions to avoid gas investment where possible) which is part of Pathway #1, is a very credible option that represents a distinct vision for the system and the province. This vision is based primarily on domestic "Need", separate and apart from the other plans identified by Hydro. It should not be immediately dismissed given its unique characteristics:

[2] NFAT Business Case, Executive Summary, page 38, (August, 2013).

- The most notable of these characteristics is that Plan 1 (All Gas) requires only $3.218 billion (2014$) in direct capital spending over the period 2013-2032 as compared to $7.614 billion for Plan 4 (K19/Gas24/250MW) or $16.088 billion for Plan 14 (PDP)[3].

- Also of high value is that Plan 1 (All Gas) requires the least lead-time for decisions, which permits minimized commitments to be made in the current climate. A decision to pursue this vision means no new generation construction commitments are likely required until 2019[4], or even longer if complementary enhanced DSM, life extension or import arrangements are included.

- Finally, Plan 1 provides the potential for the lowest level of rates for the near-term, and a substantial part of the rate burden is solely to pay off "sunk" costs from Keeyask, US Interconnection and Conawapa planning (for the purposes of NFAT this is assumed as approximately $87.64 million per year starting in 2016 until 2032, if the 75:25 debt equity ratio is targeted; in practice this may be a 100% write-off as of the decision to abandon each project)[5].

- Pathway #1 is not inconsistent with the province's Clean Energy Strategy or Sustainable Development Principles in that the pathway is accommodating of new hydraulic generation as "the economic case moves forward"[6]. For example Pathway #1 includes Plans 7/8 which build Conawapa for 2029, only three years later than the PDP. In addition, construction of new gas generation for 2023 or later will not lead to any significant requirement to actually run this generation except in drought/emergencies until approximately 2030[7]. During this time there are many energy supply sources that can be considered to help reduce actual running time.

Hydro's filing is incomplete in terms of analyzing how to best optimize Plan 1 under a full assessment of a more modest Need-Based vision for the system. It is InterGroup's understanding

[3] Appendix 11.1: Net Capital Expenditures, REF-REF-REF net expenditures of current dollars including constant dollar capital cash flows, projected escalation and interest capitalized during construction, taken as sum of net expenditures from year ending 2013 to year ending 2032. page 1, 4 and 6.
[4] MIPUG/MH-I-10(a).
[5] Manitoba Hydro states that it is prudent to return to a 75:25 debt:equity ratio in a timely manner, similar to the IFF approach, to achieve by the end of 2031/32 in the NFAT Business Case, Chapter 11: Financial Evaluation of Development Plans, page 4, (August, 2013).
[6] Manitoba's Clean Energy Strategy, page 13.
[7] PUB/MH-I-121b.

that such an optimization may be under review as part of undertakings provided to La Capra, but this is yet to be provided[8].

5) Given the information available, an Opportunity-based vision (advance Keeyask, take up MP export deal, build new transmission to US) is likely better than a Need-Based vision utilizing Plan 1 (All Gas).

Plan 4 (advance Keeyask to 2019, assume Natural Gas for 2024, build a 250 MW interconnection to Minnesota) which is part of Pathway #3, appears to be a better option for ratepayers than Plan 1 (All Gas)/Pathway #1, and is by far more preferable for most other interests (GHG emissions, First Nation investment, jobs, taxes, government revenues). This is true despite the above-noted benefits of a Need-Based vision, and despite current limitations on the information available to assess the full benefits of an optimized Plan 1.

6) Past experience with hydraulic generation and interconnections suggest added benefits from large infrastructure that should not be ignored.

Also in favour of a hydraulic and interconnection based approach, such as represented by Pathways #3-#5, is the following less tangible factors:

- Historically in Canada, hydraulic resources have repeatedly proven to be the lowest cost and most stable sources of power over the long-term.
- Interconnections by Manitoba Hydro to other markets have proven to be critical complements to baseload hydraulic resources.
- In Manitoba, the majority of adverse environmental and socio-economic impacts required to develop further Nelson River hydropower have already been experienced.
- Interconnections provide the ability for Manitoba to benefit from true diversity in power supplies (e.g., thermal, wind) through complementary relationships in MISO. Added hydraulic generation in Manitoba could be viewed as “putting all the eggs in one basket” if not for interconnections – with interconnections the better image is to build to Manitoba’s strengths (technical and available resources) and achieve diversity through complementary trading relationships.
- Visions based on added baseload generation in Manitoba and added cross-border transmission are far more flexible to address unexpected load requirements, such as

[8] As of January 28, 2014 when this report was in final preparations.

from economic development occurring in Manitoba at a faster pace than expected (e.g., new industrial loads).

7) **The 750 MW transmission option (Pathway #4) should likely be pursued. Part of the rationale is based on future adaptation and optionality, which is not fully explored in Hydro's materials.**

In addition to Plan 4 (K19/Gas24/250MW) there is a solid basis to consider increasing the line capacity from 250 MW to 750 MW. This option is not well presented in Hydro's filings as it requires consideration of "optionality" (which is the subject of only two paragraphs[9] of the original filing with no quantification)[10]. Given the 250 MW line effectively foregoes the future opportunity to expand to the larger size if desired, and the 750 MW maintains a more complete suite of future options, it is likely advisable within the cost ranges identified (which is within 1% of the cost to ratepayers) to pursue the 750 MW Interconnection.

8) **Evidence does not yet support Conawapa as being in ratepayer interests. The project does show massive benefits to other stakeholders, particularly the provincial Government. The option for Conawapa for 2026 should continue to be protected, while minimizing the ongoing cost commitment. If conditions do not improve, Conawapa should not proceed. If a rebalanced relationship with the province can be secured, there may be ways for Conawapa to be beneficial for ratepayers even if market conditions do not improve.**

In respect of Conawapa, the evidence provided does not support the project. However, decisions about whether to proceed with Conawapa are not required until 2018 at the earliest. In the meantime, the following is noted:

a. Both the economics[11] and financial evidence[12] indicate Conawapa would not be an advisable project to pursue for ratepayers in any near-term horizon under current assumptions.

b. Conawapa provides massive additional benefits to stakeholders other than ratepayers, in particular the provincial Government revenues (capital taxes, debt guarantee fee and

[9] NFAT Chapter 14 pages Pages 48-49.

[10] Note that some initial quantified analysis is provided in response to PUB/MH-I-279.

[11] See NFAT Chapter 14 Table 14.2. Plan #6 (no Conawapa) versus Plan #15 (with Conawapa 2025) shows limited EV benefits, but significant added P10 downside risk. This is prior to the 2013 update, which generally served to reduce the economic value of plans with Conawapa more than the smaller Pathways. Also note that these values, as described in Appendix B to this submission, poorly reflect the full scale of risks (P10) related to interest rate on the capital-intensive plans.

[12] See Appendix C: Results of InterGroup Financial Analysis.

water rentals). Under current conditions, the only reasonable basis to proceed with Conawapa would be under a revised economic balance with the provincial Government (for example, Appendix C reviews the effects of a possible temporary 15 year respite on provincial Government charges related to Conawapa). If conditions improve in the next four years, the need for a government charges rebalancing may be narrowed.

c. Securing a greater quantity of Conawapa's output under firm contracts improves the economics of Conawapa. As a result, before 2018 all reasonable efforts should be directed towards locking in fixed price[13] contracts for Conawapa output, in the MISO market or elsewhere.

d. Between 2014 and 2018, the prospect of a significant Conawapa upswing in ratepayer benefits (either through improved conditions, or a Government charges rebalancing) suggests continuing to protect the project for a 2026 in-service date. This is also consistent with the Clean Energy Strategy which recommends continuing to protect this project through the planning and licencing phase[14].

9) Other planning activities and decisions should be continued or expanded, such as pursuing all economic DSM and customer self-generation, etc. These actions should occur starting in the near-term, regardless as to Pathway selected.

As a complement to whichever Pathway is selected, Hydro should continue to pursue all economic DSM, customer generation, natural gas system expansion, and related load management activities where these activities can achieve a Levelized Unit Cost (LUC) less than the value of the power secured.

a. Hydro's programming should consider an expanded scope to permit financial incentives for customer fuel switching to natural gas, and procurement of all offered customer-generated power and interruptible loads at up to full value (e.g., avoided cost, export pricing).

b. The focus of conservation efforts should be on those forms of DSM which offer value to the utility given the costs incurred. Hydro should deemphasize DSM tests other than the Program Administrator Cost Test ("PACT") and Levelized Utility Cost ("LUC") assessments.

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[13] This could include contracts where prices vary, but only in relation to a pre-defined variable, such as inflation or other benchmark.

[14] Manitoba's Clean Energy Strategy, page 2 (2012). Available here [Referenced February 2, 2014]: http://www.manitoba.ca/iem/energy/pdfs/energy_strategy_2012.pdf.

10) There are aspects of the NFAT that are instructive with respect to Hydro's normal rate reviews before the PUB. These items should be addressed in future GRAs.

a. Hydro should remove the current interim caps on the Curtailable Service Program recognizing the longer-term planning benefits that can come with peak capacity DSM[15].

b. Hydro's NFAT proposals result in near-term rate impacts that compound with ongoing utility cost increases. Hydro should be cautious about adopting approaches to calculating asset depreciation that exacerbate these effects (i.e., serve to increase near-term depreciation expenses) such as the Equal Life Group approach.

In addition to the above recommendations and conclusions, the InterGroup submission highlights the following comments:

- A distinction is important between Scenarios (future conditions that may credibly unfold) and Sensitivities (analytical exercises to test the outer bounds of conclusions based on more extreme inputs).
- Hydro's approach to scenario analysis is appropriate and a better tool for the NFAT than what might otherwise appear to be more advanced analytical techniques, like Monte Carlo simulation.
- The load forecast used for Hydro's NFAT filing was tested for reasonableness (Appendix D), and found to be reasonable for the purposes of long-term planning. The P10 and P90 bounds provide a wide range of conditions that are appropriate for scenario analysis. Analysis of these Scenarios was not thoroughly included in the NFAT filing (for the most part only low scenarios were considered), and this should be completed as a cross-check before deciding on a final Pathway/Plan to be followed. More extreme sensitivities could also benefit the decision-making process, including sensitivities based on high possible load conditions which have been largely ignored in the main NFAT filing.
- Hydro's approach to modelling DSM savings, as an adjustment to the load forecast rather than a competing resource, is appropriate for this NFAT for testing between the various Pathways. This conclusion reflects the overall approach adopted by Hydro, focused on the Opportunity-based vision.

[15] Note that this was approved on an interim basis in the last Hydro GRA, with further consideration proposed to be given during the NFAT review, in Board Order 43-13 Directive #13 (April 26, 2013).

- The NFAT analysis could be aided through a number of incremental improvements, but none are fatal to the analysis or conclusions:
    - Development of P10 and P90 ranges based on modelling the economics with all 99 water flows, rather than the mean of water flows.
    - Additional high and low sensitivities for important inputs that could materially impact conclusions, such as low export prices (this is done by InterGroup as part of Appendix C) and high and low load.
    - Testing of the sensitivity of financial/rate impacts across varying discount rates (this is done by InterGroup as part of Appendix C) including discount rates higher than presented by Hydro as part of PUB/MH I-149(a) REVISED.
    - There is room for advancement in finding ways to present the optionality value of the larger Pathways (in particular Pathway #4).

2.0 THE INTERGROUP ASSIGNMENT

InterGroup has been retained by MIPUG to review Hydro's NFAT Business Case Submission in light of the following:

a. The concerns of industrial customers; and

b. Normal regulatory principles and considerations relevant to Hydro as a rate-regulated, Crown-owned and hydropower generation dominated utility.

InterGroup's review was also completed in light of the OIC 128/13 requirements on the PUB with respect to the scope of the NFAT and priority areas for assessment, and in light of the provincial policy framework for Hydro as contained in the Manitoba Hydro Act s.2 (purposes and objects) and other provincial policies (e.g., Clean Energy Strategy, Sustainable Development Principles).

In addition to the above context for the InterGroup review, the PUB directed MIPUG in Order 67/13 to identify and advance the general interests of all General Service customers of Manitoba Hydro in addition to concerns raised by MIPUG members during the NFAT review, and to notify the Board where its interests diverge from the interest of other commercial operations.

This section sets out the over-riding considerations that guided InterGroup's review of Hydro's filing.

2.1 OVERVIEW OF MIPUG MEMBERSHIP AND CONCERNS

InterGroup set out to review Hydro's NFAT Business Case in light of the facts and concerns expressed by the MIPUG members. This section sets out InterGroup's understanding of the key concerns of MIPUG which guided the InterGroup review.

MIPUG is an association of major industrial companies operating in Manitoba. The purpose of the association is to work together on issues of common concern related to electricity supply and rates in Manitoba. To that end, MIPUG intervened in each of the Board's reviews of Hydro rates since 1988, as well as the Board's review of the Centra Gas acquisition in 1999 and Hydro's Major Capital Projects in 1990.

MIPUG membership currently includes the following companies:

- HudBay Minerals Inc., Flin Flon;
- Tolko Industries Ltd., The Pas;
- Canexus Chemicals, Brandon;

- Koch Fertilizer Canada ULC, Brandon;
- ERCO Worldwide, Virden;
- Gerdau Long Steel North America – Manitoba Mill, Selkirk;
- Amsted Rail - Griffin Wheel Company, Winnipeg;
- Enbridge Pipelines Inc., Southern Manitoba;
- TransCanada Keystone Pipeline, Southern Manitoba; and
- Vale, Thompson.

The majority of the MIPUG load is in the >100 kV class; however, MIPUG also includes companies who represent over half of the smaller 30-100 kV class.

The MIPUG members compiled information on each of the member companies for an economic impact study in the spring of 2012, as an update to earlier 2005 and 2008 versions that had previously been filed with the Board[16]. According to the information available at the time the 2012 economic impact study update was undertaken, MIPUG member companies:

- Provide approximately 4,300 full-time jobs and employ 1,300 contract workers;
- Contributed almost $2.3 billion to provincial GDP;
- Contributed $260 million in taxes to local governments, Manitoba and Canada; and
- Have $6.5 billion in capital investments in Manitoba.

In short, the study indicates MIPUG companies are significant contributors to Manitoba's economy and are particularly important to some of Manitoba's larger communities outside of Winnipeg. Nearly all of the 4,300 full-time and 1,300 contract jobs are cited as being located outside of Winnipeg. Many MIPUG companies are the largest employers in their respective communities. The combined annual sales of MIPUG companies total almost $2.6 billion. MIPUG members sell over 90% of the products they produce outside of Manitoba.

[16] The 2005 Economic Impact of the Manitoba Industrial Power Users Group was requested in 2008/09 GRA proceeding. The IR response (MIPUG/MH-1) in the 2008/09 proceeding indicated it was being updated and the 2008 update was provided as Exhibit MIPUG-9 on March 25, 2008.

In previous interventions, MIPUG members, as major power users, have consistently expressed concern about the long-term interests of Hydro's domestic customers with respect to the following items:

- The need for stability and predictability of domestic rates over the long as well as short-term.
- The need for strong regulatory oversight and approval of all rates charged by Manitoba Hydro.
- The need to ensure Hydro's long-term system planning promotes the lowest and most stable rate regime over the long-term.
- Protection for domestic customers against higher rates or risks caused by Hydro's investments in subsidiaries, new export ventures or major new capital programs that do not promote least-cost planning focused on the utility's domestic electricity customers.
- Protection for customers against changes in government charges for items such as water rentals, debt guarantees or any other policy-related factors that increase the general rates charged.
- Assurance that rates to each customers class reflect Cost of Service calculated in accordance with principles appropriate to Canadian regulatory practice for Crown electric utilities.

MIPUG has indicated that the basis for their intervention in PUB hearings is that electricity prices matter greatly to industrial customers. MIPUG members have indicated that they are concerned about persistent electricity rate increases undermining the advantage of operating in Manitoba. Cost-based, stable and predictable electricity prices are cited as being critical to the success of Manitoba industry, providing a competitive advantage that helps to offset some of the challenges of operating in Manitoba, including climate and distance to market. In many cases members face direct competition globally, where cost structures can be far different than in North America. Over time, having rates slightly lower than the next lowest jurisdiction may be entirely insufficient to address these challenges.

MIPUG members have also highlighted that Hydro's willingness to accommodate industry cooperation in power acquisition has at times been disappointing. The experience has been that Hydro shows less receptiveness to possible cooperation on long-term beneficial projects than industry would have hoped, in particular:

1) **Curtailable:** Recent proposals by Hydro to limit access to DSM capacity programming, in the form of the Curtailable Service Program. There are members who have indicated they may be prepared to join this program, which provides capacity DSM and can be a long-term resource for Hydro, but Hydro has proposed to limit participation.

2) **Customer self-generation:** There are a small selection of MIPUG members who have potential renewable energy projects associated with their facilities. This typically relates to generating power from waste products (e.g., low grade heat, hydrogen). At present, such generation facilities are not in place. In other jurisdictions, such generation potential can often be pursued on the basis of providing this energy benefit to the utility, and the customer will receive a full "marginal cost" based financial recognition for the supply. In Manitoba, however, Hydro has not traditionally been willing to entertain such options, either in respect of the financial recognition or participation in economic or technical feasibility work. As a result the power resources remain undeveloped.

3) **Energy-Related Demand Response:** Within Hydro's trading activities, there are times that arise where export markets have high prices and acute power needs. It is reasonable to assume that at some of these times, large customers in Manitoba could choose to reduce their loads in exchange for sharing the benefits of the resulting added export sale with Hydro. The effect is much like opportunities that industrial customers are able to capture in many other jurisdictions, where relationship with the utility and the markets are differently structured. A Manitoba concept for this type of program has been suggested to Hydro, but Hydro has not pursued it to date[17].

2.2 RATE MAKING AND ECONOMIC EVALUATION PRINCIPLES FOR A HYDRO-ELECTRIC CROWN UTILITY

This testimony has been prepared taking into account regulatory and rate making principles appropriate to Manitoba Hydro as a Crown-owned and hydroelectric generation dominated utility. This section reviews key principles and their rationale.

2.2.1 Background

As a general principle, prices for electricity in Manitoba are regulated, based on a premise that customers generally, or a single class of customers specifically, require protection from a monopoly supplier who could, in the absence of a principled decision on the fairness of rates, charge them prices that are unreasonable. The "reasonableness" in this context represents a number of considerations, including:

- The price for service to customers overall reflects the costs of providing that service[18] ("Revenue Requirement").

[17] MIPUG/MH-I-24(b)

[18] See, for example, Bonbright, J.C., 1960, "Chapter IV – Cost of Service as the Basic Standard of Reasonableness".

- The costs are measured based on the assets that are used and useful in the period in question, and at a level that reflects prudency in the costs of acquiring the asset (the "Used and Useful" and "Prudent Investment" tests)[19].
- The costs are allocated on a principled basis to the various classes of customers that share in receiving service from a single system ("Cost of Service").
- The rates ultimately charged are to yield the appropriate revenues to Hydro under varying conditions and meet a series of important rate objectives ("Rate Design").

2.2.2 Revenue Requirement and the Used and Useful Test

Hydro's annual revenue requirement is subject to review and approval by the PUB and includes all reasonable costs required to run the utility. The PUB has the ability to determine which costs are reasonable versus which costs are not, including determining what amounts of Hydro's spending (all, or potentially not all) is ultimately recovered from ratepayers, and when.

In making this determination, the PUB must look to the years in question (the "test years")[20], and to a lesser degree, to relevant subsequent periods to the extent needed to take into account the critical concepts of rate stability. For example, Bonbright notes, in relation to the instability of rates that can arise with an over-focus on short-run costs that such pricing methods should not "deprive consumers of those expectations of reasonable continuity of rates on which they must rely in order to make rational advance preparations for the use of services"[21].

In the case of Manitoba Hydro, the concept of providing rate stability is typically linked to the concept of Hydro meeting its financial targets.

2.2.3 "Heritage Resources" and Hydraulic Generation

The above principles and excerpts from the literature highlight normal utility regulation and ratemaking principles as they apply to the power utility industry generally and in particular to private utilities. A unique additional consideration is at work in jurisdictions such as Manitoba (and similarly in systems such as Quebec) where the development of power systems has not been pursued on a private investor/equity return basis. This is a common feature of hydro dominated systems, given the unique nature of hydro projects:

[19] Charles F. Phillips, The Regulation of Public Utilities (3rd. ed,) at pp. 340.
[20] For example, as far back as 1922, the New York Public Service Commission noted: "Consumers should not pay in rates for property not presently concerned in the service rendered, unless- (1) Conditions exist pointing to its immediate future use; or (2) Unless the property is such that it should be maintained for reasonable emergency or substitute service; and in studying these two exceptions the economic factor should be carefully considered." Elmira Water, Light & R.R., 1922D Pub. Util. Rep. (PUR) 231, 238.
[21] Bonbright, J.C., 1960, Page 396-397.

- **Capital Required:** Hydro projects require massive commitments of capital. If this capital is to be sourced from investors (equity) it requires a considerable return on a relatively high equity base (debt:equity ratio) to attract sufficient investment to complete a large project. Also the nature of very capital-intensive projects is that there is a very high "fixed" annual cost related to the investment, and low operating costs. For example, a typical investment by Hydro today in each $1 billion project likely requires 1%-2.5% of the capital cost (on average) for depreciation and a further interest cost that could be in the range of 5%, for a minimum net cost in the first year of $60-$75 million (if not offset by new revenue, this would mean a 5%-6% impact on rates[22]).

- **Low Initial Returns:** Hydro projects would normally be expected have extremely low (or zero, or slightly negative) economic returns in the near-term, but basically assured to have high returns over the medium to very long-term. Government entities, relying on a debt guarantee of the citizenry can find these economics attractive. This pattern of economic returns however, is not generally attractive to private sector investors needing to pay annual dividends to investors.

- **Annual Risk:** Hydro projects have no assurance of economic returns in any single given year, or even in any single decade, due to water flow variation. It is possible to calculate a very favourable return statistically over any longer-term period, but the duration of drought risk, with its attendant cost and cash flow challenges, would be unattractive to private investors, or would demand excessive risk premiums on equity returns.

Hydro projects are exceedingly challenging economic projects to develop, and are exceedingly risky from year to year due to water flows, but are in fact among the lowest risk (if not the lowest risk) power projects available over any longer-term horizon. While a comparable capacity of thermal plant would cost a fraction of the cost of hydro plants, and bring a typically more stable annual cost profile year-to-year over the short-term (due to not being subject to droughts), the intense long-term risk with respect to fuel prices and almost certain higher life cycle cost over the full plant life cycle make such plants more attractive to investors, and typically much less attractive over the long-term to ratepayers.

For a jurisdiction with a good hydro potential, there exists a potentially excellent development opportunity, but a very challenging investment opportunity. If the returns are permitted to be very high, this development can attract private capital. More typically, jurisdictions in Canada with this resource profile elect to use the "Patient Capital" that is more characteristic of provincial governments (or aboriginal governments) including low-cost borrowings that can be available to provincial governments (even on a highly leveraged basis) when backed by the full faith and credit of the citizenry. This latter

[22] At approximately $12 million per percentage point of rate increase.

government entity approach leads to far more advantageous rates, particularly for a cost-based Crown utility like Manitoba Hydro.

Against this backdrop, an overriding principle that must be brought to bear in regulation is ensuring that the costs of these very large developments (e.g., costs to develop new projects, costs to depreciate existing projects) are recognized in the appropriate time period, and in particular not in advance of when the bulk of the economic benefits of the plant arise. For baseload developments with good long-term economics that get better with time, one role for regulation is to ensure that today's ratepayers are not being burdened with costs that are appropriately collected from ratepayers later in a hydro plant's life when the economic prospects are vastly improved and the need for the plant is apparent.

It is also important to acknowledge the fundamental tenets underlying electricity pricing and policy existing in Manitoba since at least the 1970s[23]. Manitoba electricity prices are based on the costs required to operate the public power electricity system put in place in past years. These prices reflect the underlying "heritage resources" developed and paid for by Manitoba electricity consumers[24] who took on the costs and risks related to major generation and transmission developments (both one-time investment risks, as well as ongoing risks related to water flows, plant performance, etc.). In this regard, the generation and transmission resources currently in place (the "bulk power" system) represent the entitlements of ratepayers to attractive and stable electricity prices. Even if the PDP is developed, the heritage resources make up the vast majority of Hydro's system resources. Export revenues derived from capable cross-border transmission have been integral to this policy approach, in that the ability to export power enables development (and in some cases allows advancement of development) of large northern hydro stations, in excess of what would be required for solely domestic requirements at any given point in time.[25] This allows larger scale and more economic plants to be developed, and allows rates to be lower over the long-term than they would otherwise be (were the major hydro developments not otherwise possible) and more stable (since fluctuations and risks related to Manitoba load levels can be offset in part by complementary changes to quantity of power exported, and since the ongoing costs of hydraulic generation are not subject to fuel price fluctuations).

Similarly, these same basic tenets have been the basis for the NFAT and the Manitoba Government Clean Energy Strategy. These plans are founded on the ability to construct generation projects sooner than they would otherwise be triggered for solely domestic use, and to use the intervening "advancement"

[23] This basic set of principles is set out in numerous documents from the 1970's through the present, including reports of Manitoba Hydro, the provincial government, the PUB, as well as previous agencies such as the Manitoba Energy Authority.

[24] In the case of the HVDC system, there was financing from the Government of Canada, provided for the benefit of Manitoba electricity consumers.

[25] This basic relationship is set out in detail in the PUB's Report to the Minister regarding Manitoba Hydro's 1990 Capital Plan, Section 3 and Page 5-4.

period to make valuable sales to export markets. As such, Hydro's supply is bolstered, the utility has increased flexibility to address situations such as unexpected load growth, and the new hydro plants are constructed earlier, at a lower cost than would otherwise arise (due to inflation) and to have the investment partially "paid down" by early years export sales. In each case, the premise put forward by Hydro is that these early generation and transmission investments are aimed at maintaining stable and low cost electricity for Manitobans, along with associated advantages for cost-of-living, jobs and investments, and development of renewable public resources (and in the current hydro developments, opportunities for northern community investment).

The challenge for developing this type of heritage resource is near-term rate impacts. Unlike major new generation brought on-line in places such as Ontario in past decades, which resulted in major rate increases, Manitoba Hydro has traditionally intended to develop new generation such that there are long-term beneficial impacts on Manitoba ratepayers, but relatively limited near-term adverse impacts. This principle is core to assessing the fairness over time (inter-generational) of an NFAT.

At the same time, utility regulation is rooted in the broad public interest, and while customers' interests via rates must be front-and-center, there are other customer benefits that must also be assessed. For example, customers may benefit from added flexibility of the utility to meet unexpected load growth requirements under scenarios where larger quantities of power have been developed. Customers may also benefit from added cross-border transmission to import emergency power at times of severe unexpected system supply constraints, which, though infrequent, can be exceedingly costly to customers (such as recent events in Newfoundland[26]).

Finally, benefits arising from added payments to Government, all other things being equal, are a positive attribute of hydro development. However, this cannot be a prime determinant in selecting a power scheme. Also payments to Government, if set at an inappropriately high level (particularly considering the Government does not face the inherent risks as do ratepayers related to unknown future economics), can result in massive lost opportunities for both ratepayers and Government through projects that are not built due to poorer overall ratepayer economics. This scenario is prevalent in the NFAT particularly with respect to Conawapa.

[26] Newfoundland experienced an island-wide power outage from January 2 - 8, 2014 which led to a series of rolling blackouts as the island is not connected to external power supplies.

With respect to analysis of long-lived projects, it is also important to distinguish between credible possible future events expected, which combined can be used to create "Scenarios", and the concept of extreme testing of modelling results, through "Sensitivities" or a form of stress test. The key difference is the purpose of each analysis:

- **Scenarios** are created within the range of expected potential future conditions, and as such reflect varying degrees of likelihood of future conditions. They are tested because they represent a reasonable range of how future conditions may affect the various Plans available. Scenario analysis should be conducted comprehensively to represent possible future conditions.
- **Sensitivities** in this context are not meant to represent expected conditions. They are mean to represent possible extreme conditions that can be well outside the bounds of what is reasonably expected today. The purpose of testing sensitivities is to determine where thresholds may lie; where the Plans that may be selected and conclusions drawn today may break down in the event unexpected to extreme futures arise, or from the perspective of atypical current day viewpoints.

Hydro has developed a range of Scenarios for the purposes of testing the plans, for the three major variables (Energy and Gas Prices, Capital Costs, and Economic Conditions) as well as for Load (portrayed as P90/P10 probabilities). Sensitivities have been used in a much more limited way in the NFAT filing.

2.3 GENERAL SERVICE CUSTOMER CONSULTATION

As directed in PUB Order 67/13, MIPUG has undertaken consultation activities with two general service groups: the Manitoba Hydro Consumer Advisory Group on energy matters and Manitoba Chambers of Commerce[27].

[27] To date, two meetings have been attended of the Consumer Advisory Group on energy matters and at both meetings an overview presentation on the NFAT review, implications on business in Manitoba and ways to get involved were discussed. MIPUG circulated a newsletter to this group with more detail on the filing and process of the NFAT and has plans to continue the newsletter series as well follow-up meetings may occur to get feedback on the process thus far.

As well, meetings have occurred with the Manitoba Chambers of Commerce with the following objectives.

1) Helping play a role as conduit of NFAT hearing-related information (from an intervenor's perspective) to the Chamber.
2) Sharing with the Chamber the conclusions of the MIPUG group, any evidence that it will file, and arguments that it ultimately plans to make.
    a) If the Chamber has specific views (supportive or otherwise), it is then possible they may provide these directly to the Board; or
    b) If the Chamber so requests, MIPUG can share the Chamber's perspectives with the Board for them.
3) If the Chamber does wish to provide their perspectives directly to the Board, MIPUG can provide informal assistance in this undertaking – who to contact at the Board, what will be expected, etc.

To date the general concerns coming out of the consultation process have largely reflected two areas:

1) the magnitude of the PDP for ratepayers, industry and Manitoba's economy (especially in light of the substantial level of borrowings that will be guaranteed by the provincial government); and

2) a need for balance of near-term and long-term costs and benefits for ratepayers, including inherent concern over the present climate of uncertainty in energy markets in contrast to the long-term commitments that underlie the PDP.

InterGroup's submission seeks to assess Hydro's proposals in light of these priority concerns.

3.0 OVERVIEW OF NFAT FILING AND HYDRO'S APPROACH

Hydro has provided a comprehensive and detailed presentation of the NFAT materials in support of their basic contention that the Preferred Development Plan ("PDP") is the best outcome for ratepayers and for Manitoba. This includes extensive analysis that in many places goes well beyond that provided by most utilities undertaking a resource planning exercise.

The NFAT is by necessity a review of the broad vision for the power system, as much as it is a review of the technical merits of the paths selected within a given vision. MIPUG/MH-I-1(a) clarifies that Hydro's definition of "need" is solely based on serving domestic load and existing export contracts. MIPUG/MH-I-1(b) through (e) clarify that Hydro views the other objectives (economic development, environmental, etc.) to be beneficial properties for assessing between alternatives, but none represents a required characteristic of the ultimate plan to be selected. This is a reasonable interpretation of the NFAT exercise.

Hydro's filing and underlying case has been assessed with a focus on the following basic resource planning steps:

1) **Approach to resource planning and developing the NFAT,** including perspectives on "need", determination of the planning horizon, identification of the fundamental alternatives, and development of "pathways" to be considered as part of the analysis.

2) **Inputs to the analysis,** including capital costs, energy prices, economic conditions, etc.

3) **Analytical tools applied,** including whether the various economic and financial analyses, and ratepayer impacts have been properly modelled and analyzed.

Each of the above steps is addressed in this section.

3.1 APPROACH TO RESOURCE PLANNING AND DEVELOPING THE NFAT

Hydro's NFAT Business case has been developed to portray the outcomes of an underlying internal corporate Power Resource Planning process[28], and to support the current Preferred Development Plan. Hydro's Power Resource Plans are typically completed annually, to determine a PDP. The latest integrated Resource Plan available is from 2012/13. In general this plan does not vary dramatically from the major actions contained in Hydro's Power Resource Plans for a number of years.

[28] See for example Appendix B: 2011/12 Power Resource Plan.

3.1.1 Purpose of Resource Planning

Utility or Power Resource Planning is a standard and necessary function for any utility, representing the internal efforts required to ensure a variety of outcomes, such as:

- Fulfillment of the utility franchise obligations to serve (in this case particularly the Manitoba Hydro Act Section 2)[29];
- Meet customer expectations;
- Provide for future growth of the utility entity; and
- Meet broad governmental policy objectives. This is relevant even in the context of a private utility, but much more so with a Crown utility.

3.1.2 Hydro's Unique Approach to Resource Planning

Despite the above common requirement for Resource Planning, Hydro's NFAT departs from most typical planning exercises in two fundamental ways:

1) Hydro's planning is exceedingly long-term in nature. For example, the recent Minnesota Power Resource Plan covers the period 2013 to 2027[30] (with 2018-2027 considered the long-term requiring further future actions). Much of BC Hydro's resource planning options are assessed to meet the forecast electricity needs of the province over the next 20 years[31]. In contrast, the actions proposed by Hydro's PDP covers all major power requirements through 2041 with decisions proposed today regarding Keeyask and Conawapa generation resources[32], and economic scenarios are analyzed over a 78-year horizon.

2) Hydro's planning completes only a relatively cursory review of the pure concept of "need" before exploring broader and larger scale resource alternatives or "opportunities".

[29] Purposes and objects of Act.

> 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.

[30] Minnesota Power 2013 Resource Plan, (March 1, 2013). Available here [Accessed February 1, 2014]: http://www.mnpower.com/Environment/ResourcePlan.

[31] BC Hydro Integrated Resource Plan, page 3 (November 2013). Available here [Accessed February 1, 2014]: http://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/0000-nov-2013-irp-summary.pdf.

[32] NFAT Business Case, Chapter 8, page 19 (August, 2013).

As discussed below, the two above characteristics of Hydro's NFAT are linked.

3.1.3 Major Resources versus Smaller Incremental Additions

Traditional ongoing resource planning for utilities is typically an incremental exercise; that is, the vast majority of the utility's future requirements are addressed by existing supply and relatively modest changes to that supply mix. These changes are often to relatively flexible resources – such items as Independent Power Producers ("IPPs") supply, DSM, customer generation, solar, small run-of-river hydro improvement or additions, thermal additions or new wind (referred to below as "Flexible" resources). These supply additions are flexible in that they are relatively quick to procure, small enough to be easily absorbed into the system, and often repeated at somewhat frequent intervals as required. In this manner, plans can be very adaptable to changing conditions year-to-year, and can reflect a relatively small commitment to the decisions required in each annual plan.

Only occasionally do utilities pursue procurement of very large new resources (a sort of "System Building Block"), such as major hydro sites or complexes, large inter-jurisdictional transmission, nuclear generation, etc. Such resources are entirely different than normal flexible utility resources:

1) They require planning well in advance of the in-service date.
2) They are often larger than the system requires at the date they are brought in to service.
3) They are extremely complex and require major (and somewhat speculative) investment well in advance of the development, to confirm the viability, cost, community support, etc.
4) They are relatively inflexible to adapt to changing conditions once commitments are made – for example, these projects may require combinations of counter-party support, outside investors, very long-lead equipment, very customized engineering, major early infrastructure, and multiple jurisdictional regulatory reviews.
5) Economics can be dependent on long-term perspectives as these resources are usually longer-lived and not the most cost-effective in the short-term.

Hydro's NFAT reflects a resource plan predicated on not one, but multiple "building block" type resources (Keeyask, Conawapa, new cross border transmission, and major export relationships). It is among the most complicated and expansive power development proposals in Canada in recent decades[33]. The underlying scheme is in fact considerably more complicated than portrayed in the NFAT, as it includes

[33] Included in this consideration are aspects of the project size in relation to the proponent utility, the underlying franchise area, the relative inflexibility of the plan to adapt to future conditions, and the requirement for multiple counterparties to be in support.

complementary decisions in respect of a number of aspects that are excluded from the PUB's scope as defined in the Terms of Reference regarding the NFAT review, most notably the development of Bipole III[34].

3.1.4 Initial Decisions Relate To Vision

At its core, the above distinction gives rise to issues of vision. There are effectively two potential distinct and incompatible visions that could be advanced for Manitoba's power sector at the present time. One of these visions is based strictly on "need" and one based on broader capture of "opportunities":

1) **Potential Vision #1: NEED BASED - Minimize Commitments - Focus on the pure traditional concept of "need":** The first possible vision is guided by priorities such as minimizing commitments and investment, avoiding future possible regret over today's actions, minimizing resource consumption, avoiding debt, and avoiding making large decisions in a period of uncertainty where smaller decisions are sufficient. Even if acknowledgement is made that attractive large new northern hydro resources are available as the next ideal building block resource at some point in the future, efforts would focus on determining how long a commitment to these resources can be avoided. A Need Based vision would likely incorporate the following aspects:

   - ***Load Forecast:*** A Need Based approach would be consistent with an extensive assessment of the Manitoba load forecast, load forecast methodologies and alternative load forecast scenarios. Projects would tend to be designed around only the date of in-service required, with risk mitigation for possible unexpected load growth.

   - ***DSM:*** The scope of electric power DSM could be approached aggressively and in its broadest sense – including non-traditional DSM activities that have economical Levelized Utility Costs ("LUC"s). The LUC is a measure of whether a given resource is cost-effective (kW.h) for the utility to procure given the costs required to be committed. This could include items such as buy back of customer generation at resource value (not linked to the rates paid by the customer), targeted subsidization of gas extensions, advocacy and financial incentives towards customer fuel switching initiatives[35], or pursuit of energy efficiency measures that might substantially fail many of the combined or customer-

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[34] In particular, although Bipole III is framed as a reliability initiative by Hydro, it is clear that the development is complementary to the NFAT proposals. For example see OL10-2 provided as Exhibit MH#154 in the Hydro 2010/11 and 2011/12 GRA which notes at page 25 that absent Bipole III, 1500 MW of natural gas generation would be targeted for 2017 with an additional 500 MW by 2025. This compares to the current "All-Gas" option that requires only two 7FA SCGTs (or approximately 446 MW) in this same time frame, as per NFAT Chapter 8 page 20.

[35] PUB/MH I-253b.

specific DSM metrics, but which customers may nonetheless pursue for other reasons.[36] The bounds of DSM activity would remain within utility cost metrics – only procure power savings where the costs to procure exceeds the "value" of the power saved.

- ***Non Utility Generation:*** This approach could also focus heavily on the fullest possible role that could be played by resources outside of Hydro's ambit (e.g., customer generation, small commercial IPP development, net metering, community power projects). This may even include measures adopted in recent years in other provinces, such as Ontario Feed-In Tariffs for small scale customer generation, or British Columbia style "Calls" or issuing formal Requests For Proposals ("RFP"s) for non utility suppliers of power resources.
- ***Imports:*** Investigate the potential to expand definitions of reliable and secure imports. Investigate procurement of additional contracted imports.
- ***Life Extension:*** Ensure maximization of existing system resources, including life extension activities on resources such as Brandon unit #5 (coal).
- ***Carefully Assess Exports:*** Explore the options to not renew existing contractual relationships, except where these arrangements are beneficial to avoiding the need for new resources (e.g., diversity agreements do provide net energy benefits).

Combined efforts on the above measures could be expected to materially delay the date for required in-service of new resources presently expected for 2023[37]. For example, Hydro's load forecast growth approximates 400 GW.h/year[38]. Life extension activities on Brandon Unit #5 may be able to secure more than 800 GW.h of emergency backup power that can delay the need for new resources by two years. The potential for full renewal of the existing diversity contracts (which are presently assumed to not be renewed in the NFAT) are of a similar magnitude[39]. Each 50% increase in the DSM program (which totals over 800 GW.h per year at the base level) equates to a year of delayed new resource requirement. Complementing these initiatives with a

[36] Many advanced energy saving technologies fail the traditional DSM tests of Total Resource Cost (TRC) or Customer Payback because they are not strictly economically justified. Regardless as to this fact, many of these technologies are routinely adopted by customers who value other aspects that the technology offers, such as altruism, environmental stewardship, or other social status. Traditional DSM analysis focused on TRC or customer metrics like payback can often conclude that these technologies are not to be supported, and utilities may fail to provide any financial support or advocacy, even though such support could readily pass utility-focused metrics such as the Program Administrator Cost Test (PACT).

[37] NFAT Business Case, Chapter 14, page 40 (August, 2013).

[38] MIPUG/MH-I-022.

[39] Total 844 GW.h per year per Appendix 4.2, page 18 as the "Hydro Adjustment". For the 2012 analyses, these contracts are forecast to be terminated and not renewed. For the 2013 analyses, the 844 GW.h per year has been extended as 307 GW.h/year until 2030, presumably reflecting the extension of the 200 MW Great River Energy diversity agreement as noted in LCA/MH-I-333.

single gas unit (1688 GW.h SCGT, 2460 GW.h CCGT or a 4-6 year energy supply)[40] plus expansion of peak capacity management options (such as the Curtailable Rates Program) could conceivably delay for a decade or more the need to make commitment decisions on new hydro plants or new cross border transmission, to at least 2024.

The primary limitation of the Need-Based Vision is the potential for lost opportunity. As noted by the Board's Independent Expert Doctor Lonnie Magee during the 2010/11 GRA, in discussing the concept of risk[41], failing to pursue expansion at a time when it was advisable represents just as real (and potentially just as large) a risk from foregone action as pursuing an action that later proved inadvisable:

> "Manitoba citizens could be losing a fortune. It – the difference is that there would be no sort of symbol of the mistake. There would be no 'thing' sitting there that people could say, Well, that was wrong. It would just be money – a lost – a huge lost opportunity without a convenient symbol to – to point at.
>
> So I think it's – it's helpful to – it could be helpful to keep in mind that there's no way out of this – of avoiding this risk. Either way there's a big risk." (Dr. Magee, Transcript page 6123-6124; Hydro 2010/11 and 2011/12 GRA).

The other potentially significant limitation of pursuing a strictly Need Based vision is load risks that can arise during periods of large load additions. Under these conditions, a system can be challenged to meet the demands of load growth, or be forced into pursuing suboptimal resources that can meet the timing (where better suited resources may take too long to be put into service).

2) **Alternative Vision #2: OPPORTUNITY BASED - Capture Opportunities – Focus on best combination of Building Block resources, and assess whether changing conditions continue to support this conclusion:** This alternative vision focuses on opportunities that exist at the present time to pursue system expansion for domestic needs as well as added export-oriented development within the bounds of the mandate set out in the Manitoba Hydro Act, in particular marketing power "to persons outside the province on terms and conditions acceptable to the board"[42].

[40] NFAT Business Case, Chapter 7, Table 7.4: Natural Gas-Fired Resource Option Characteristics, page 31 (August 2013).

[41] Dr. Lonnie Magee in direct examination by Mr. Gavin Wood, Manitoba Hydro 2010/11 and 2011/12 General Rate Application Transcript pages 6123-6124 (May 5, 2011).

[42] Manitoba Hydro Act, section 2(b).

Actions within this vision require larger commitments, longer lead times and more speculative spending than under a Need-Based vision. Assessment needs to focus on the very long-term, as the key resources are very long-lived. However, the assessment of this vision for the power sector requires less of a need to solve in detail the role of flexible resources than a Need-Based assessment. This is because when making decisions about hydro plants ten years or more in advance of when they are needed, it is neither possible nor advisable to concurrently decide on complementary smaller resources which can be put in place with only two years lead time (and as such can wait eight years before decisions are required, for the same target in-service date). Flexible resources can be used to gap fill in the short-term, complement building block resources, address project delays or load developments, etc. It is not reasonable to require that all decisions be made today about the comprehensive potential economics or role of solar or wind or DSM as of 2023 or 2026; in contrast, decisions are required today to decide if Keeyask should be built, delayed or abandoned or Conawapa is to be protected for 2023 or 2026.

This approach does not suggest that flexible resources such as DSM and wind should not be considered as part of an Opportunity-Based NFAT assessment. The difference is that these flexible resources should not be burdened with a need to justify the precise investment to be made in future. The key issue with future flexible resources that arises when assessing building block resources is ensuring the decisions made today are not inferior in light of the role that can be played by future flexible resources:

a. Whether by deciding today to pursue a major building block resource, this may adversely affect future flexible resources that would otherwise have been economic (e.g., whether decisions today to build Keeyask, for example, will undermine or preclude future potential to pursue economic DSM). This can arise if the two sources are in physical competition (e.g., building a storage style hydro plant on a site precludes a future run of river plant on the same site) or are in economic competition (e.g., building Keeyask will bring on such a large quantity of power that hypothetically there will be no economic basis in future to pursue DSM, even though that DSM could have otherwise been economic).

b. Additionally, Whether pursuing what appears to be the correct decisions today in respect of major resources will provide to be incorrect in light of future actions on flexible resources. For example if in future it becomes very easy to secure quantities of very low cost DSM or wind power, will this future acquisition serve to eliminate the economic rationale on which Keeyask was based (e.g., whether pursuing more DSM in the future will mean the decision to pursue Keeyask today, which may appear correct today, will ultimately prove to be the incorrect decision).

The key consideration to resolve these questions is whether the flexible resources and the major building block resources are competing or are complementary.

An Opportunity based vision will also typically reflect a far wider range of options for resource timing, sequencing, etc. The concept of Pathways is a very suitable and appropriate design element. Any assessment of individual locked-in Plans for analysis will always be excessively rigid compared to what the future truly provides as feedback loops before each subsequent decision. **Modelling of Pathways and the optionality that they provide is critical to fully appreciating the full benefits of decisions that unfold over time.**

Justifications for spending under an Opportunity-Based vision will require a different approach and different content than under a vision based solely on need.

3.1.5 Hydro's Approach Based on Opportunity-Based Vision

Hydro's NFAT filing is well designed to justify Hydro's proposals, ***assuming a precedent decision that the Opportunity-Based vision above is to be pursued, and not the Need-Based vision***.

Within the Opportunity-Based vision, Hydro's filing considers a suitable range of energy sources, technologies, and timing options to consider if the PDP is indeed the best plan. Hydro's filing generally (with a few exceptions) applies analytical metrics that are suitable for evaluating alternatives within this vision. This Opportunity-Based vision is also better aligned with the Manitoba Clean Energy Strategy[43]; however that strategy would equally not appear to preclude a Need-Based approach for the time being followed by hydro generation at a later date.

Unfortunately, Hydro's filing does not provide the ideal information for evaluating the potential of a strictly Need-Based vision.

Plan 1 (All Gas) is a reasonable starting point for analysis of this Need-Based alternative. However, Hydro's filing fails to provide an appropriate optimized plan (such as a "Plan 1A") which balances the appropriate gas investment with other potential flexible resources such as DSM, customer generation,

[43] Manitoba's 2012 Clean Energy Strategy highlights as the Manitoba's Clean Energy Priority Actions including 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 and improve Manitoba's transmission system reliability, increase export capabilities, and enhance the development of new hydro and wind energy by constructing a new Bipole III 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, page 2.

wind, solar, import arrangements, life extension projects, etc.). This hypothetical Plan 1A would be similar to Plan 1 (All Gas) in that gas generation would be assumed to be built (simple cycle or combined cycle as appropriate) once base load resources were required. The difference is that the Plan 1A concept would first pursue all other economic and suitable sources of power before triggering gas additions. In this way, the existing Plan 1 (All Gas) remains as the default option and all other options that are advantageous to natural gas would be pursued as a priority resulting in Plan 1 (All Gas) being effectively the upper bound costs on what an optimized Plan 1A may entail. It is presently not clear how much optimization may be possible in developing a Plan 1A as an improvement to Plan 1.

There are also four different analytical considerations that should be assessed in considering a Need-Based vision as compared to an Opportunity-Based scenario:

- **Horizon:** A Need-Based vision can be assessed based in part on its ability to “buy time”, to permit minimum commitment today that saves the financial strength of the utility for grander ventures in the future. This may reflect customer interests such as those with a shorter time horizon (e.g., the elderly or resource-limited mining operations) those with more acute present day concerns or possibly more difficult financial conditions (e.g., the poor or distressed industries). **Proceeding to Opportunity-Based visions should not excessively impinge on those parties focused only on the shorter horizon solely in order to benefit the longer-term.** A common standard for new bulk power projects such as hydraulic generation is that adverse impacts on financials or rates from new developments should not exceed somewhere in the order of 3-7 years until the “cross-over” point of costs into benefits is reached, and should not be excessively costly during the time frame up to the cross-over. In economic terms, this means projects should not only be economically preferable (positive NPV) over long periods, but also over shorter horizons. In this case, under reference scenario conditions, the financial analysis for Hydro’s PDP leads to higher rates (at times up to 10% higher) starting immediately and continuing until 2035 as compared to Plan 1 (All Gas), which is problematic.

- **Thresholds:** Proceeding from a Need-Based vision to the larger Opportunity-Based focus is acceptable under the Manitoba Hydro Act, but is not required to fulfill Hydro’s mandate (e.g., see MIPUG/MH I-1(a)). For this reason, **a relatively high threshold for customer benefits should be applied to Opportunity-Based plans as opposed to Need-Based options to properly compare the two different visions.** In part this would reflect that larger plans bring intangible exposure related to, for example, the presence of much more debt, technology risk or extreme “black swan” risks that are not readily identified or quantified[44]. In the NFAT business

[44] Black Swan risks are possible future conditions that have not been previously hypothesized; extreme outliers.

case, Hydro's primary conclusions regarding the PDP rely on consistent comparisons (including discount rates) between the various scenarios without regard for the larger scale and intangible risks/exposures that this scale brings. As discussed in Appendices B and C to this submission, proper analysis could include analytical tools such as higher discount rate sensitivity. Hydro has not provided such analysis; one example was completed as part of preparing this testimony and is provided in Appendix C: Results of InterGroup Financial Analysis to this submission.

- **Customer Impacts (e.g., affordability):** In the context of plans that affect ratepayers, the extent of customer impacts that are occurring due to ongoing utility cost pressures (outside of planning activities) is a key backdrop to determining which vision to unfold. Hydro's filing confirms that customer impacts will be high regardless of the plan selected. Rate increases are projected to be approximately double the rate of inflation throughout the next two decades and higher and more sustained than has been experienced for many decades in Manitoba, if ever. This backdrop helps indicate the degree of resiliency or economic context for ratepayers, which in general reflects lower resiliency or lower ability to absorb added rate increases over the next 20 years than has been the case in recent years. This factor suggests a possible preference for smaller Need-Based options.

- **Complementarity of Risks:** Hydro's PDP is affected by future risks that also affect customers directly in other areas. Hydro has focused the NFAT on three risks: capital costs, real discount/interest rates (or economic conditions), and export prices (or energy prices).

  - If the PDP is selected and construction costs rise, then rate impacts will be larger than anticipated. However, this outcome likely arises because economic conditions are relatively good, demand for workers is high, material costs are high, etc.

  - Similarly, the PDP will drive power rates higher than anticipated if real interest rates are high, likely reflecting more significant competition for investment dollars globally. In this environment, Hydro's ratepayers (both industrial and residential) are likely facing economic conditions that are good – and that can more readily better support slightly higher rate levels.

  In short, these two risks are likely complementary to the PDP; i.e., the worst outcomes occur for power rates during times when customers have the most resilience to be able to accept slightly higher rates. In contrast:

  - the risk of low energy prices for the PDP (low natural gas prices) reflects a condition where Hydro's industrial customers in Manitoba will be paying higher power rates at the same time as their competitors in other jurisdictions will benefit from a relative price advantage (lower power prices than the Reference scenario due to low gas prices). Consequently the low power price risk is likely compounding for Hydro's customers – higher domestic rates in Manitoba with lower energy prices elsewhere would serve to undermine the "Manitoba Advantage" represented by attractive power rates. For this reason, sensitivity to adverse export price scenarios may be more acute than sensitivity to the other risks identified.

For this reason, it is unfortunate that Hydro's NFAT Business Case (a) does not better present a comprehensive plan that fulfills the more basic Need Based vision before proceeding to analyze the larger Opportunity Based options; and (b) does not provide a better sensitivity assessment of the exposure of each Plan to extreme low energy prices/gas prices. InterGroup's submission includes both of these analyses as part of Appendix C: Results of InterGroup Financial Analysis.

3.2 INPUTS TO HYDRO'S NFAT ANALYSIS

Hydro's NFAT Business case relies inherently on the assumptions regarding key inputs. While assessing the reliability of the various inputs has not been the key focus of InterGroup's assignment, certain specific assumptions are addressed below.

3.2.1 Load Forecast

Hydro's load forecast reflects relative consistency with past practice, and a reasonable approach to analysis. Industrial load forecasting in particular is notoriously difficult when there are a limited number of customers. Appendix D: Load Forecast and Approach to DSM Modelling sets out InterGroup's review of past Hydro load forecasts, and the extent to which the current forecast results remain reasonably consistent with past practice over the past two decades.

Hydro's load forecast remains a reasonable approach for determining short-term requirements and revenues. The Hydro load forecast also reflects a reasonable approach to assessing the NFAT Plans. It is clear that changes to the load forecast are to be expected, and that these changes, even if small (e.g., 0.1% change in growth rates) can make massive changes in the required in-service date of new plants. For this reason, it is typically not required, when assessing major building block resources, to achieve a high degree of accuracy in a single load forecast as it is to test a series of scenarios.

The most significant weakness for the industrial load forecast, from the perspective of a long-term NFAT review, is the failure to explicitly consider scenarios that result in much higher or quicker developing future industrial load (Hydro's Potential Large Industrial Load or "PLIL"). For example, MIPUG/MH-I-43(b) shows the load balance in the event that the full PLIL presently forecast for the first 17 years of the load forecast arrives in the next 5 years (before Keeyask), consistent with the nature of this load to arrive in large increments rather than small annual additions. Under this scenario, small energy deficits are seen one year before Keeyask is scheduled to come into service under the Plan 14 (PDP), and deficits are approached again just prior to Conawapa coming into service. No other development plan was modelled for this scenario, but it can be expected that no other plan could serve this degree of load addition without altering the sequence of generation resource timing or export commitments. Plans such as Plan 1 (All Gas) would be able to be redesigned to accommodate higher loads, but this redesign could only be achieved at a cost that is not presently modelled in the NFAT. This is a clear benefit of the PDP and similar plans; the benefit this provides is not presently captured within Hydro's NFAT filing. It is important to note that such a high degree of industrial load growth is uncommon, but it might represent only 1-2 large loads arriving in the next 5-7 years – there are at least 1-2 major potential loads (and likely more) that could credibly require power from Manitoba Hydro over this period which are not yet contained within the Load Forecast.

3.2.2 Financial Targets

Hydro's financial analysis is designed based on achieving a 75:25 debt:equity ratio by 2031/32 and maintaining 1.2 times interest coverage after that date. These assumptions reflect Hydro's financial targets as used for rate setting purposes and in the integrated financial forecasts. Note however that these targets were adopted during a time when 75:25 debt:equity ratios yielded a target level of retained earnings that was roughly comparable to the cost of a major drought. In particular, 25% equity yielded a required reserve level that was in the range of $2-$2.5 billion, which the cost of a major drought on the existing system, during a period of higher energy prices, was also in the range of $2-$2.5 billion. Therefore, the targeting of this level of equity/reserves at that time could be justified.

Under NFAT assumptions, Hydro's evidence indicates that the retained earnings levels achieved well exceed that required to address a five year drought. MIPUG/MH I-006(c)(iii) shows the costs of the extreme five year drought (in nominal dollars) for 2032/2033, which is the period after Conawapa would be in service, as set out in Table 1 below.

Table 1: Cost of Drought per NFAT - 2032/33 ($ Billions) [45]

	P10	P50	P90	Targeted Reserves
Plan 1 (All Gas)	1.3	2.3	3.3	5.1-6.6
Plan 4 (K19 Gas 250MW)	1.6	2.8	4.1	6.3-8.1
Plan 14 (PDP)	2.1	3.7	5.4	8.3-10.9

Table 1 above indicates the drought costs vary significantly with differences in the input assumptions, but that all values are well below the targeted level of reserves. Note however that the drought costs in the table above are not net financial losses (true net financial losses are much lower). Per MIPUG/MH-I-7, the net financial losses for the time frame 2034/35 for a five year period replicating the worst drought on record would tend towards $1 billion for each of the plans under Reference energy prices, $2 billion under high energy prices, and almost no net loss for low energy price scenarios (not including compounding interest effects that would occur due to increased borrowings)[46]. Table 2 below provides the net financial losses that would occur under the major Plans 1 (All Gas), 4 (K19/Gas/250MW) and 14 (PDP).

Table 2: Net Financial Losses During a repeat of the 1987-1992 Flow Sequence in 2034/35 ($ Millions)[47]

	Energy Prices		
	Low	Ref	High
Plan 1 (All Gas)	-345	-1140	-2034
Plan 4 (K19/Gas25/250MW)	-161	-1040	-1993
Plan 14 (PDP)	21	-1013	-2143

It is not necessary within the NFAT process to re-examine Hydro's proposed retained earnings levels and financial targets. It is important to note however that these levels of reserves add significant costs for ratepayers and cannot be justified to be collected solely on the basis of being necessary for ratepayer benefits. Ratepayers only benefit from Hydro's retained earnings in two ways – first through lower rates (less interest cost), and second through more stable rates when retained earnings absorb the financial impacts of periodic extreme conditions (positive or negative).

[45] MIPUG/MH I-006(c) iii.

[46] Drought is further addressed at MIPUG/MH-I-7. In this response the net flow related revenue for each of the 8 plans included in the financial analysis is shown. Taking the net flow related revenue for each flow year, less the average shown at the bottom of the table, indicates the variance that can arise due to drought. The net losses that occur in each year can then be determined by adding to the net flow related variance the net income otherwise forecast for that year (e.g., REF-REF-REF for Plan 1 (All Gas) is $175 million per Appendix 11.4; Plan 14 is $285 million). This analysis demonstrates that the longest period of net losses for Hydro would continue to be 5 to 7 years, and the net losses in nominal terms.

[47] MIPUG/MH-I-7.

Despite this weakness in Hydro's rate-setting approach assumed for the financial analysis in the NFAT Review, it does provide a sufficiently reasonable long-term proxy for analysis purposes. It is not a reasonable approach for the setting of specific rate levels during future GRAs. It is also important to recognize that excess net income and retained earnings which go beyond that justified on the basis of achieving stable rates are not a benefit to customers – they are solely a benefit to Hydro's shareholder, and analysis of the NFAT outcomes needs to reflect this allocation definitively, so as not to confuse what are costs to ratepayers and what are benefits to Hydro's shareholder.

3.2.3 Depreciation

Hydro has assumed depreciation rates consistent with its proposals under IFRS as the NFAT analysis was developed with the underlying assumption that Manitoba Hydro would transition to IFRS prior to the in-service dates for any of the new assets in the development plans[48]. Depreciation item reflects a substantial part of the rate impacts of typical capital intensive projects in the early years after construction. These rate impacts require careful consideration as part of a GRA.

For the purposes of a typical NFAT-type assessment, depreciation rates can also be relevant considerations that can serve to skew the impacts of capital projects on ratepayers. This is because major capital projects often reflect a pattern of impact with higher rates for a short period of time (e.g., 3-7 year crossovers) with lower rates occurring after this time. In the case of Hydro's current NFAT, these effects are not front-and-center given the typically long cross-over points (>20 years) and the levelized rate impacts assumed by Hydro for the first 20 years as part of its NFAT rate design criteria[49]. For this reason, additional analysis of depreciation has not been necessary to this point in time.

3.3 HYDRO'S USE OF ANALYTICAL TOOLS IN NFAT EVALUATION

Hydro's NFAT analysis of the future development scenarios includes the following key aspects:

- Chapter 9 regarding economic analysis under forecast conditions;
- Chapter 10 regarding economic analysis under varying conditions (risk);
- Chapter 11 regarding financial forecasts, including rates, under both forecast and varying conditions;
- Chapter 13 regarding multiple account evaluation;
- PUB/MH-I-279 regarding optionality;

[48] MIPUG/MH I - 034a.

[49] Manitoba Hydro NFAT Business Case, Chapter 11: Financial Evaluation of Development Plans, page 4 (August 2013).

- PUB/MH-I-149a (REVISED) regarding NPV of domestic rates; and
- Various additional specific analyses regarding specific approaches to risks related to drought, differing load forecasts, and differing DSM levels.

In general, Hydro's approach to analysis (outside of issues noted above regarding Need) is comprehensive, reasonable and more thorough than typically found in utility resource plan assessments. Most notably, Hydro's NFAT Business case provides a full assessment of the future forecasts for the entire company and all factors affecting rates, where the more typical practice is to focus only on the incremental effect of a resource plan and ignore the "common" underlying drivers of rates. This latter more typical approach is inferior as it fails to provide context for the backdrop against which rate pressures arise.

A small number of material concerns arise with Hydro's approach, particularly in regard to Chapter 10: Economic Uncertainty Analysis – Probabilistic Analysis and Sensitivities. This relates primarily to the use of discount rates, which are addressed in Appendix B: Economic Analysis Critique of this testimony.

Specific comments in regard to Hydro's overall approach to analysis and modelling are below.

3.3.1 Sunk Costs

Hydro has approached the economic modelling (Chapter 9) on the basis of future costs (ignoring sunk costs). This is appropriate for economic modelling, as sunk costs are not a component that can be affected by the go-forward decisions that can be made today. Further, the financial analysis in Chapter 11 does include the impacts of Sunk Costs in domestic rates, so these effects are not ignored.

3.3.2 Scenario Analysis of Development Plans

Hydro has elected to treat risk by scenario analysis on a range of specific future conditions. This includes 27 scenarios varying three metrics (economic conditions, capital costs, and energy prices). This is in contrast to the alternative approach of tools like Monte Carlo simulation. For the purposes of the NFAT review, Hydro's choice is appropriate, for three reasons:

1) The range of variables and issues Hydro is addressing in each model run is massive and complex. Monte Carlo analysis is typically understood to require large numbers of "runs" of a model to yield probabilities (at minimum hundreds to thousands of runs). As Hydro is evaluating 14 or more possible Plans, this approach would likely be unworkable.

2) Monte Carlo analysis requires a reasonable estimation of the probability distribution of many variables, including interrelationships between these variables. Hydro's approach does not require

an assessment of the full distribution, only the identification of three points (Low, Reference, High) and an estimation of the likelihood of these values occurring. While Hydro's approach may fail to fully present Monte Carlo type outputs (e.g., it may fail to fully reflect extreme low probability "tail" distributions), it is unlikely that this would be a significant limitation of Hydro's approach, as without reliable input distributions it is also uncertain that any such low probability output results from a Monte Carlo simulation would in fact be valid.

3) Monte Carlo modelling is typically far more impenetrable and impossible to replicate. This gives rise to challenges for both public and expert review. For example, specific individual outcomes of Monte Carlo analysis may be worthy of investigation, but it can be impossible to replicate the input variables that created the data point. In contrast, under scenario analysis extensive input and output data can be provided for each scenario that permits error-checking, confidence and additional insight as to how key variables interact.

3.3.3 Sensitivity Analysis

As compared to Scenarios, the concept of sensitivities can capture analysis conducted to determine the outer bounds of decision-making, such as determining the threshold capital costs at which a selected Plan is no longer preferred and an alternative plan would become a better choice. Hydro has provided some DSM Sensitivities to explore the outer bounds of DSM (4.0 times the base forecast), but similar sensitivities have not been tested for a number of other variables.

InterGroup has undertaken discount rate sensitivity analysis in Appendix C: Results of InterGroup Financial Analysis of this submission.

3.3.4 Optionality and Adaptation of Plans

Hydro's analysis in the NFAT fails to fully reflect the impacts of optionality and adaptation. In particular, the mathematics of the economic modelling in the NFAT fixes a decision on all future actions (what to build), then models that scenario as a set of locked-in actions against a 78 year future with a range of future sets of conditions. This approach fails to reflect that some of the decisions regarding what to build need only to be made in the future after better (or at least more timely) information arises. In general, the approach adopted by Hydro will tend to undervalue Plans which serve to increase the range of future options available. This is most notable in Plan 6 (K19/Gas/750MW), which leaves the decision between gas and Conawapa open until at least 2018 (reverting to Plan 15 (K19/C26/750MW)) or 2025 (reverting to Plan 12 (K19/C33/750MW), and including options to defer or cancel future investment. For example, The Expected Value (EV) of Plan 14 (PDP) in Chapter 10 assumes the decision to pursue the PDP is fixed, regardless as to what occurs over the next 4 years. As a result, it includes situations where interest rates are high, export prices are low, capital costs are trending high, and despite all this Hydro still pursues Conawapa for 2025/26. In practice, under those conditions, as of 2018 (when the decision must be made whether to pursue Conawapa or defer) the likely outcome is in fact to defer or abandon Conawapa. In Hydro's filing, there are two additional plans that complement Plan 14 (PDP). The first is Plan 5 (K19/Gas25/750MW/Sales) and the second is shown on Hydro's Figure 14.2 under pathway 5, but is not given a number or further assessed anywhere in the NFAT (K19/Gas26/C30/750MW – note that gas here could be proxy for any flexible resources that could permit delay in Conawapa, including DSM, wind, etc). Comparing the Plans 14 and 5 can be done row-by-row in Table 10.4 of Manitoba Hydro's NFAT Business Case (reproduced below)[50]:

Figure 1: Probabilistic Analysis Quilt Incremental Economics – All Sections

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	
Energy Prices	Discount Rates	Capital Costs	Millions of 2014 NPV dollars											
Low	Low	H	-4043	-7769	-3309	-3792	-3190	-3459	-3506	-3418	-3642	-3554	-2855	-2841
		Ref	-3049	-5403	-2401	-2532	-1877	-2124	-2166	-2130	-2177	-2138	-1616	-1410
		L	-2247	-3666	-1655	-1590	-890	-1069	-1099	-1175	-1030	-1022	-703	-292
	Ref	H	-463	-3056	-1297	-1212	-911	-2510	-2161	-1191	-2816	-2323	-730	-2155
		Ref	208	-1478	-582	-278	95	-1368	-1050	-185	-1559	-1153	257	-929
		L	750	-323	6	408	837	-473	-176	548	-585	-243	974	20
	High	H	1204	-796	-284	25	117	-2029	-1413	-182	-2383	-1622	203	-1810
		Ref	1708	384	323	785	963	-994	-434	679	-1243	-592	1060	-698
		L	2114	1245	822	1336	1580	-189	327	1297	-364	201	1674	157
Ref	Low	H	-5014	-7167	-1760	-2511	-1796	206	-334	-2041	498	0	-2103	853
		Ref	-4020	-4802	-852	-1251	-482	1541	1006	-753	1963	1415	-865	2284
		L	-3217	-3064	-107	-309	504	2597	2073	202	3110	2531	49	3402
	Ref	H	-671	-2354	23	-46	341	152	104	85	170	190	109	470
		Ref	0	-775	738	887	1346	1295	1215	1091	1427	1360	1097	1696
		L	542	380	1326	1573	2089	2189	2089	1824	2401	2270	1813	2645
	High	H	1308	-82	879	1091	1258	109	391	998	2	366	1041	268
		Ref	1812	1098	1487	1851	2104	1144	1370	1859	1143	1396	1898	1380
		L	2218	1959	1986	2402	2721	1949	2132	2478	2022	2189	2512	2235
High	Low	H	-6435	-6719	-355	-1499	-692	3819	2796	-1006	4455	3410	-1694	4372
		Ref	-5441	-4353	552	-239	621	5154	4135	282	5921	4826	-456	5803
		L	-4638	-2616	1298	703	1607	6210	5203	1237	7068	5941	458	6922
	Ref	H	-1158	-1767	1241	941	1398	2746	2308	1127	2993	2571	713	2940
		Ref	-487	-189	1956	1874	2403	3888	3420	2134	4250	3741	1701	4166
		L	55	966	2543	2560	3146	4783	4293	2867	5225	4652	2417	5115
	High	H	1210	533	1956	2017	2246	2170	2127	1993	2236	2228	1691	2203
		Ref	1713	1712	2563	2777	3092	3206	3106	2854	3377	3259	2549	3315
		L	2120	2573	3063	3328	3709	4010	3867	3473	4256	4051	3163	4170

Colour Legend < -3000 0 > 3000

Looking at the reproduced Table 10.4, the values indicate that with high energy prices (the bottom third of the table) a decision initially to pursue Plan 14 (PDP) will always lead to continued pursuit of Plan 14 (i.e., the NPV values of Plan 14 (PDP) are highest as compared to any other plan, and proceeding to build Conawapa would be advised). However, if, as of 2018 when the decision to advance or delay Conawapa needs to be made, energy prices are then expected to be low (top third of table), then the decision to pursue Conawapa will turn on interest rates. Under a low interest (discount) rate the Plan 14 (PDP) is still

[50] Hydro's Table 10.4 as reproduced above is subject to significant limitations, as described in Appendix B, and must be used with caution. For the approach applied above, based on solely comparing within a single row, these issues are not a concern.

better than Plan 5 (K19/Gas/750MW/Sales) (rows 1 through 3); however under reference or high interest (discount) rates it would be better to abandon Conawapa and revert to Plan 5 (K19/Gas/750MW/Sales) (the fourth through ninth rows). Under reference export prices it is only under high interest (discount) rates that Plan 14 (PDP) with Conawapa would be abandoned. In this example, capital costs would not be a determining factor under any scenario; however note that in the event that as yet unidentified scenarios arose (e.g., low gas capital costs, but high hydro capital costs) this optionality is also of value.

Hydro attempts to address the concept of optionality and adaptation in PUB/MH-I-279, but this cursory analysis fails to give the concept the profile required as a key planning tool. Further, Hydro's NFAT filing is less than ideal in that multiple financial models from the same path are often not provided. For example, Plans 14 (PDP), 5 (K19/Gas25/750MW/Sales) and the unnamed plan K19/Gas25/C31/750MW are complementary plans from an adaptation perspective, but only Plan 14 is subjected to financial modelling. Similarly Plans 6 (K19/Gas31/750MW), 12 (K19/C31/750MW) and 15 (K19/C25/750MW) are complementary but only Plans 6 and 12 are subjected to financial modelling.

4.0 SPECIFIC COMMENTS AND CONCERNS ON ECONOMIC AND FINANCIAL ANALYSES

This section addresses the conclusions coming out of the key quantitative analytical components of the NFAT filing including Chapters 9, 10 and 11 regarding economic and financial analysis. It is supported by Appendix B: Economic Analysis Critique which provides InterGroup's concerns with the economic analysis conducted by Hydro, and Appendix C: Results of InterGroup Financial Analysis which provides a detailed presentation of key conclusions arising from InterGroup's financial modelling.

The section is organized into the following sections:

- Ratepayer Basis for Concern with Preferred Development Plan;
- Problems with Hydro's Economic Analysis;
- Economic and Financial Analysis – Results; and
- Other Comments.

4.1 RATEPAYER BASIS FOR CONCERN WITH PREFERRED DEVELOPMENT PLAN

Hydro's analysis in the NFAT shows lengthy (20+ year) adverse incremental rate impacts from developing Plan 14 (PDP) of approximately 0.5%/year compounded, as compared to the lowest cost plans. While this impact may appear small, the end result is that industrial customers, representing approximately 20% of Hydro's revenues, will be responsible for almost $400 million in added rates paid over the first 20 years of the PDP compared to the Plan 1 (All Gas) option[51]. Although this value appears large, the financial analysis in Chapter 11 of Hydro's NFAT Business case indicates that revenue requirement impacts to amortize the planning costs already incurred (sunk costs) are a significant factor in neutralizing the differences between Plans 1 (All Gas) and 14 (PDP) as: (a) under Plan 1 (All Gas), these costs are amortized into rates at a faster pace, while (b) under Plan 14 (PDP) these project costs are amortized into rates over the full project life as part of depreciation expense once the resource comes in-service. These sunk costs are responsible for $1.6 billion in costs charged to ratepayers under Plan 1 (All Gas)[52],

[51] Per Appendix 11.4, the total added rates paid by domestic customers from 2014/15 to 2033/34 under Plan 14 versus Plan 1 is $2.36 billion ($46.4 billion Plan 1 versus $48.8 billion Plan 14). Of this, approximately 17% represents the industrial customers share for >100 kV plus 30-100 kV customers per PCOSS13 Schedule B1 share of total revenues.

[52] Per MIPUG/MH-I-3(c) this is the amount amortized over 2014/15 to 2032/33 excluding interest. This $1.6 billion totals 11.4% of the added revenue from rates being targeted over the period from the Plan 1 (All Gas) scenario ($13.967 billion). Including interest effects, the total impact is likely closer to 15%, or about 0.5%/year of the 3.43%/year rate levelized increases expected per Executive Summary Table 4.

or upwards of $400 million to the industrial customers alone[53]. Combined, this suggests that Plan 14 (PDP) is $800 million more costly over 20 years to industrial customers than if very limited planning dollars been spent, and a simple Need-Based scenario had been pursued throughout.

While the Plan 14 (PDP) forecasts prepared by Hydro are intended to indicate that this plan provides the greatest long-term benefits, this conclusion is not fully supported by a more detailed review of Hydro's materials. Plan 14 (PDP) requires higher levels of rates for a significant period of time (20 years). The trade-off for ratepayers is a promise of lower rates that do not arise until year 21 at the earliest. It is also important to note that Plan 14 (PDP) is not a valid presentation of a future path available to Hydro – the plan assumes benefits from a WPS sale that is now known to be unavailable in that form. As a result, Plan 14 (PDP) likely represents at best an upside scenario compared to Plan 15 (K19/C25/750MW) which is the same as Plan 14 (PDP) except that it does not include WPS. The difference in the economic analysis between the two plans is more than $300 million NPV Expected Value[54], and the difference in the financial analysis is unknown, as Plan 15 (K19/C25/750MW) was not subject to financial modelling by Hydro.

4.2 PROBLEMS WITH HYDRO'S ECONOMIC ANALYSIS

Hydro's economic analysis is used in Chapter 9 regarding Economic Evaluations under reference conditions, and Chapter 10 regarding Economic Uncertainties. For the most part, Chapter 9 provides mathematically accurate values for comparison (with specific limitations that must be kept in mind) while Chapter 10 includes a flawed methodology that requires caution with model outputs, and which results in many of the Hydro Tables and Figures being incorrect. Appendix B: Economic Analysis Critique to this filing discusses the issues with the economic analysis further.

Hydro's economic analysis does provide a significant quantity of mathematically accurate output, if used with caution (see Appendices B and C to this submission).

4.3 ECONOMIC AND FINANCIAL ANALYSIS – RESULTS

This section summarizes the results of the detailed modelling in Appendix C: Results of InterGroup Financial Analysis.

Hydro's economic and financial analysis provides for useful distinctions to be drawn between the Pathways, and to some extent between the Plans. With a large suite of plans (over 15 from Hydro alone,

[53] Industrial customers make up approximately 27% of the system energy, per Appendix 13.1 – Prospective Cost of Service Study for Fiscal Year Ending March 31, 2013 (PCOSS13), in the 2012/13 and 2013/14 Manitoba Hydro General Rate Application, Schedule B2, page 20 (July 2012).

[54] NFAT, Chapter 15, Table 14.2, using 2012 assumptions.

plus others proposed by intervenors) and with a pattern of decisions deadlines on each different plan component being required at different times, it is important to recognize that the NFAT need not prescribe the precise plan to be followed for the coming decades. However, the NFAT review must provide for the ability to make key decisions that are required today. These decisions relate fundamentally to distinctions between the various Pathways, more than to distinctions between specific Plans.

The Board must provide recommendations regarding a set of near-term decisions regarding:

a. Whether to take up the Minnesota Power (MP) export agreement (including its requirement for Keeyask for 2019 which requires construction contract awards in the near term) [Whether to proceed with Pathways #1/2 or with Pathways #3/4/5]; and

b. If yes, whether to build the required new line at 750 MW or 250 MW [Whether to proceed with Pathway #3 versus Pathways #4/5].

The decision that needs to be made today is which pathway to take (recognizing that Pathway #5 is likely inaccessible due to unlikely investment in US Interconnection by WPS). While the financial analysis does not provide data to analyze each Plan, it does provide data for a selection of Plans within each Pathway, namely:

- Pathway #1 (gas) – Plan 1 (All Gas);
- Pathway #2 (hydro) – Plans 2 (K22/Gas), 7 (Gas/C26);
- Pathway #3 (hydro, 250 MW) – Plans 4 (K19/Gas/250MW), 13 (K19/C25/250MW);
- Pathway #4 (hydro, 750 MW) – Plans 6 (K19/Gas/750MW), 12 (K19/C31/750MW); and
- Pathway #5 (hydro, 750 MW, WPS sale) - 14 (PDP).

Based on the financial modelling in Appendix C: Results of InterGroup Financial Analysis, Table 3 through Table 6 summarize the expected value benefit to ratepayers and to the government over the 20 year (2012/13 to 2031/32), 30 year (2012/13 to 2041/42), 40 year (2012/13 to 2051/52) and 50 year (2012/13 to 2061/62) horizons. In reviewing the following tables note the following:

- Benefits to ratepayers are in the form of lower NPV of domestic rates to be paid.
- Benefits to government comprise water rental fees, debt guarantee fees, capital taxes and increases in shareholder equity in Manitoba Hydro, as well as to First Nation Government partners. The analysis does not include benefits to government from other sources such as

income tax on workers employed on Hydro projects, or from indirect impacts such as changes in the level of Manitoba economic activity that arise from higher or lower rate levels and the resulting wealth of Manitobans. The vast majority (>98%) relate to the provincial Government.

Each expected value and P10/P90 percentile is reported as an increment over the expected value of Plan 1 (All Gas)[55].

Table 3: NPV of Total Benefits to Ratepayers and Government at Year 20 (2031/32) for Financial Analysis ($ Millions) at 5.05% Real Discount Rate

NPV of (Cost)/Benefit at 20 years ($ Millions) [P10/P90]	**Pthwy 1**	**Pthwy 2**		**Pthwy 3**		**Pthwy 4**		**Pthwy 5**
	Plan 1	**Plan 7**	**Plan 2**	**Plan 4**	**Plan 13**	**Plan 6**	**Plan 12**	**Plan 14**
Ratepayer Benefit	**0** [(623)/ 601]	**(954)** [(1995) /95]	**(177)** [(1,223)/ 802]	**(126)** [(1,285)/ 1,002]	**(1,379)** [(3,033)/ 258]	**(301)** [(1,543) /849]	**(914)** [(2,238) /275]	**(1,319)** [(2,935)/ 261]
Government Benefit	**0** [(357)/ 321]	**1,545** [1,201/ 1,822]	**1,354** [1,059/ 1,623]	**1,290** [892/ 1,661]	**2,948** [2,496/ 3,292]	**1,299** [885/ 1,689]	**2,830** [2,348 /3,210]	**2,954** [2,530/ 3,349]
Total Plan Benefits	**0** [(980)/ 922]	**591** [(794)/ 1,917]	**1,177** [(164)/ 2,425]	**1,164** [(393)/ 2,663]	**1,569** [(537)/ 3,550]	**998** [(658)/ 2,538]	**1,916** [110/ 3,485]	**1,635** [(405)/ 3,610]

Table 3 indicates the Expected Value (EV) benefits (in bold) with negative values indicating net negative impacts compared to the Plan 1 (All Gas) EV. The bolded values are the impact based on EV which the lower values in each cell reflect the upside and downside ranges associated with P90 and P10 conditions. All weighting are as per Hydro's NFAT.

The first set of values reflects benefits to ratepayers, while the second row is benefits to Government. The final row is the sum of benefits (which effectively represents benefits to Manitoba generally).

[55] Assuming 5.05% real discount rate and methodology explained in Appendix C: Results of InterGroup Financial Analysis.

Table 4: NPV of Total Benefits to Ratepayers and Government at Year 30 (2041/42) for Financial Analysis ($ Millions) at 5.05% Real Discount Rate

NPV of (Cost)/Benefit at 30 years ($ Millions) [P10/P90]	**Pthwy 1**	**Pthwy 2**		**Pthwy 3**		**Pthwy 4**		**Pthwy 5**
	Plan 1	**Plan 7**	**Plan 2**	**Plan 4**	**Plan 13**	**Plan 6**	**Plan 12**	**Plan 14**
Ratepayer Benefit	**0** [(586)/593]	**(850)** [(2,316)/574]	**(164)** [(1,376)/1,083]	**110** [(1,215)/1,395]	**(1,263)** [(3,658)/964]	**(138)** [(1,524)/1,204]	**(1,078)** [(3,151)/840]	**(1,031)** [(3,277)/1,074]
Government Benefit	**0** [(384)/344]	**1,896** [1,492/2,229]	**1,666** [1,300/1,996]	**1,562** [1,093/1,959]	**3,577** [3,037/4,027]	**1,572** [1,100/1,989]	**3,601** [3,018/4,086]	**3,598** [3,093/4,089]
Total Plan Benefits	**0** [(970)/937]	**1,046** [(824)/2,803]	**1,502** [(76)/3,079]	**1,672** [(122)/3,354]	**2,314** [(621)/4,991]	**1,434** [(424)/3,193]	**2,523** [(133)/4,926]	**2,567** [(184)/5,163]

Table 5: NPV of Total Benefits to Ratepayers and Government at Year 40 (2051/52) for Financial Analysis ($ Millions) at 5.05% Real Discount Rate

NPV of (Cost)/Benefit at 40 years ($ Millions) [P10/P90]	**Pthwy 1**	**Pthwy 2**		**Pthwy 3**		**Pthwy 4**		**Pthwy 5**
	Plan 1	**Plan 7**	**Plan 2**	**Plan 4**	**Plan 13**	**Plan 6**	**Plan 12**	**Plan 14**
Ratepayer Benefit	**0** [(609)/786]	**(392)** [(1,924)/1,069]	**100** [(904)/1,354]	**457** [(759)/1,742]	**(532)** [(2,971)/1,817]	**218** [(1,030)/1,540]	**(472)** [(2,664)/1,638]	**(240)** [(2,567)/1,967]
Government Benefit	**0** [(398)/367]	**2,010** [1,553/2,382]	**1,811** [1,384/2,205]	**1,686** [1,159/2,114]	**3,804** [3,183/4,282]	**1,690** [1,160/2,141]	**3,883** [3,242/4,420]	**3,830** [3,256/4,366]
Total Plan Benefit	**0** [(1,007)/1,153]	**1,618** [(371)/3,451]	**1,911** [(480)/3,559]	**2,143** [400/3,856]	**3,272** [212/6,099]	**1,908** [130/3,681]	**3,411** [578/6,058]	**3,590** [689/6,333]

Table 6: NPV of Total Benefits to Ratepayers and Government at Year 50 (2061/62) for Complete Financial Analysis ($ Millions) at 5.05% Real Discount Rate

NPV of (Cost)/Benefit at 50 years ($ Millions) [P10/P90]	**Pthwy 1**	**Pthwy 2**		**Pthwy 3**		**Pthwy 4**		**Pthwy 5**
	Plan 1	**Plan 7**	**Plan 2**	**Plan 4**	**Plan 13**	**Plan 6**	**Plan 12**	**Plan 14**
Ratepayer Benefit	**0** [(688)/ 648]	**(12)** [(1,412)/ 1,353]	**444** [(393)/ 1,553]	**780** [(282)/ 1,960]	**105** [(2,259) /2,631]	**557** [(524)/ 1,760]	**141** [(2,001) /2,434]	**439** [(1,833)/ 2,841]
Government Benefit	**0** [(408)/ 381]	**2,048** [1,565/ 2,423]	**1,849** [1,396/ 2,264]	**1,731** [1,177/ 2,187]	**3,889** [3,219/ 4,383]	**1,729** [1,171/ 2,211]	**3,986** [3,307/ 4,542]	**3,918** [3,304/ 4,495]
Total Plan Benefit	**0** [(1,096)/ 1,029]	**2,036** [153/ 3,776]	**2,293** [1,003/ 3,817]	**2,511** [895/ 4,147]	**3,994** [960/ 7,014]	**2,286** [647/ 3,971]	**4,127** [1,306/ 6,976]	**4,357** [1,471/ 7,336]

As can be seen from the tables:

- None of the Plans start to become beneficial to ratepayers up to year 20 as compared to Plan 1 (All Gas) as per Table 3.
- Table 4 shows an initial NPV benefit to ratepayers by year 30 (2041/42) for Plan 4 (K19/Gas/250MW).

Other plans require until the 40 year (Table 5) or 50 year (Table 6) horizons to achieve positive NPV benefits for ratepayers.

Note that this is in contrast to Manitoba Hydro's evidence that the 'cross-over' point for some plans occur after 10-15 years following the in-service date of Conawapa[56].

Pathway #3 and #4 provide the highest expected benefit to ratepayers through Plans 4 (K19/Gas/250MW) and 6 (K19/Gas/750MW) compared to Plan 1 (All Gas). These two plans also provide significant benefits to Government. As reviewed elsewhere in Hydro's NFAT filing, these plans include material employment, business, environmental and First Nation benefits as compared to Plan 1 (All Gas).

Figure 2 below shows the 50 year rate benefits of pursuing Plan 4 (K19/Gas/250MW) as compared to Plan 1 (All Gas) which is further described in Appendix C to this submission.

[56] Manitoba Hydro NFAT Business Case, Chapter 14: Conclusions, page 22 (August 2013).

Figure 2: Plan 1 (All Gas) vs. Plan 4 (K19/Gas/250MW) at 5.05% Real Discount Rate - NPV of Incremental Domestic Costs as Compared to Plan 1 (All Gas) Expected Value ($ Millions)

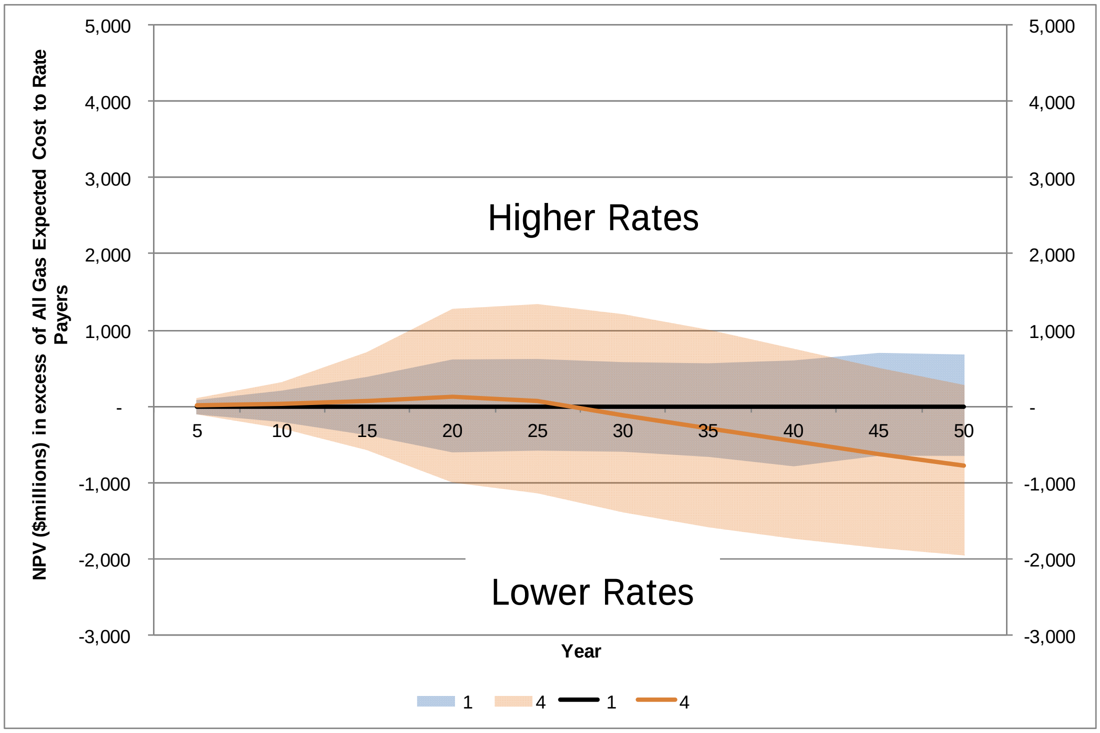

Figure 2 indicates the difference between the level of rates under Plan 1 (All Gas) and Plan 4 (K19/Gas/250MW). Plan 1 (All Gas) EV forms the zero value – values above this level mean higher NPV of rates for customers and values below the axis mean lower rates. The blue shading is the P10/P90 range of outcomes for Plan 1 (All Gas), while the orange line is the EV for Plan 4 (K19/Gas/250MW) and the orange shading is the P10/P90 spread. As shown in the Figure, Plan 4 (K19/Gas/250MW) provides some degree of added risk of higher rates (the orange zone which goes above the highest blue zone through the middle of the figure) but over the long-term provides a lower EV, and more rate upside (the band of orange on the lower part of the figure).

As a result, based on the results of this financial analysis, it appears Manitoba Hydro should take up the Minnesota Power (MP) export agreement (including its requirement for Keeyask for 2019 which requires construction contract awards in the near term) and proceed with at minimum Pathway #3 (as represented by Plan 4 (K19/Gas/250MW).

With respect to the decision between Pathways #3 and #4 (250 MW versus 750 MW Interconnection), the table above suggest a preference for Pathway #3. However, as noted earlier in this submission, this conclusion reflects an undervaluation of the optionality benefits provided by Pathway #4 as represented by Plan 6 (K19/Gas/750MW) which should be seriously considered in making the final determination.

Pending any new information to the contrary, at this time it would appear Pathway #4 (750MW) is a more valuable resource qualitatively for Manitoba, likely providing notional benefits in excess of the NPV costs to ratepayers noted above. For this reason, Pathway #4 (750 MW) is likely a preferred choice as compared to Pathway #3.

A decision to proceed with a 750 MW transmission interconnection, which provides a stronger basis for further hydro development in future (beyond Keeyask 2019, which is a prerequisite for this Plan) should also recognize potential very long-term benefits that are not necessarily represented in the financial analysis:

- Historically in Canada, hydraulic resources have repeatedly proven to be the lowest cost and most stable sources of power in the long-term.
- Interconnections by Manitoba Hydro to other markets have proven to be critical complements to baseload hydraulic resources.
- In Manitoba, the majority of adverse environmental and socio-economic impacts required to develop further Nelson River hydropower have already been experienced.
- Interconnections provide the ability for Manitoba to benefit from true diversity in power supplies (e.g., thermal, wind) through complementary relationships in MISO. Added hydraulic generation in Manitoba could be viewed as “putting all the eggs in one basket” if not for interconnections – with interconnections the better image is to build to Manitoba’s strengths (technical and available resources) and achieve diversity through complementary trading relationships.
- Visions based on added baseload generation in Manitoba and added cross-border transmission are far more flexible to address unexpected load requirements, such as from economic development occurring in Manitoba at a faster pace than expected (e.g., new industrial loads).

Past these immediately required decisions, no approval for Conawapa is required today. At this time both the economic and financial evidence available does not support Conawapa as being in ratepayer interests. This can be seen comparing Plan 13 (K19/C25/250MW) to Plan 4 (K19/Gas/250MW) or Plan 12 (K19/C31/750MW) to Plan 6 (K19/Gas/750MW) in Tables 3 through 6 above as well as in Figure 3 below.

Figure 3: Plan 4 (K19/Gas/250MW) vs. Plan 14 (PDP) at 5.05% Real Discount Rate - NPV of Incremental Domestic Costs as Compared to Plan 1 (All Gas) Expected Value ($ Millions)

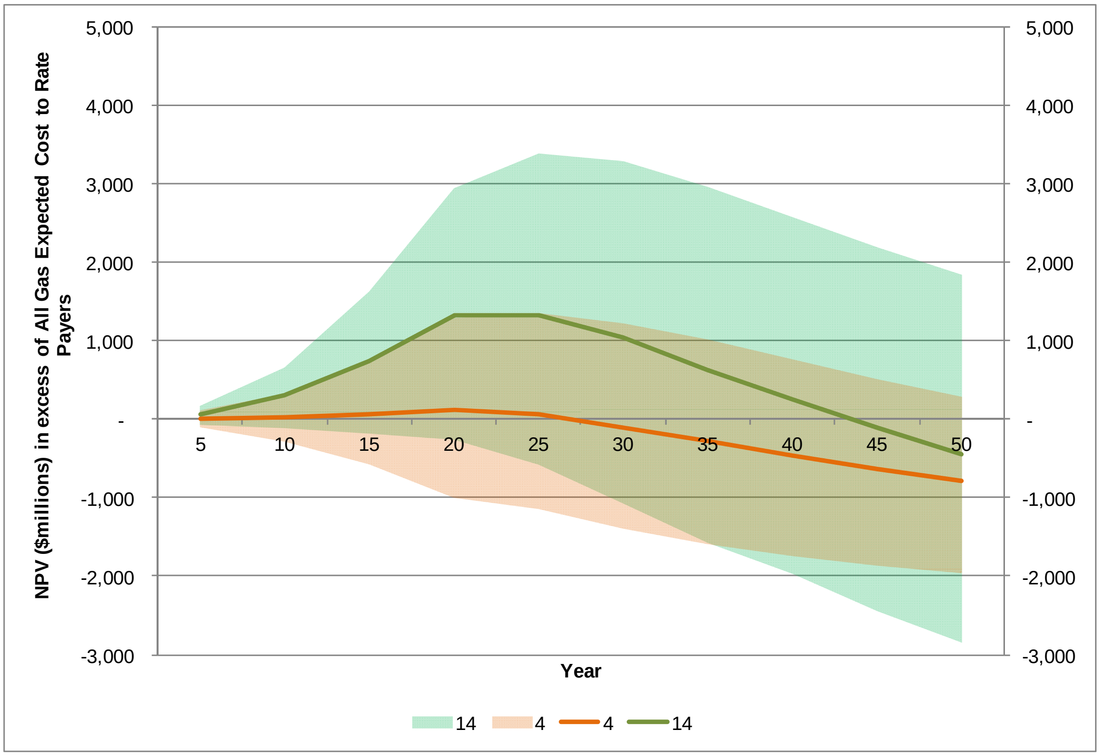

Figure 3 above shows the NPV costs to ratepayers of Plan 14 (PDP) which is in green, as compared to Plan 4 (K19/Gas/250MW) which is in orange. The figure demonstrates that under present conditions, Plan 14 (PDP) offers little upside as compared to Plan 4 (K19/Gas/250MW). While there is a range of scenarios that can arise that would lead to NPV benefits for Plan 14 (PDP) (the small green triangle on the lower right hand side of the figure) there are far more conditions that could lead to materially higher rates (the large green band at the top of the figure) and the Expected Value NPV of ratepayer costs (the green line) is notably above that for Plan 4 (K19/Gas/250MW).

The Conawapa project, as part of Plan 14 (PDP) does show massive benefits to other stakeholders, particularly the provincial Government. In addition, the upside best cases reviewed (P10/P90 conditions) indicate that Plans with Conawapa provide some potential for significant benefits under certain future Scenarios. For this reason, the option to proceed with Conawapa for 2026 should continue to be protected. The concept of “protecting” a resource involves both effort and spending commitments over time; however, these should be limited to only the required spending levels to ensure a given in-service date (in this case 2026) can be maintained. Tasks that can be deferred and not jeopardize this in-service date should be deferred. This approach to planning results in the minimum cost/risk possible to ratepayers from project development.

Securing a greater quantity of Conawapa's output under firm contracts improves the economics of Conawapa (e.g., the NPV of benefits under Plan 14 (PDP) exceeds that under Plan 15 (K19/C26/750MW))[57]. As a result, before 2018 all reasonable efforts should be directed towards locking in committed long-term export contracts for all dependable output possible.

Appendix C further reviews the potential erosion of Conawapa's impact on ratepayers under certain important sensitivity assessments, namely low export prices, and high discount rates.

In short, if market conditions do not improve, and the remaining assumptions continue as per the NFAT, Conawapa should not be built for 2026.

However, it is possible that an approach can be developed to improve the Conawapa economics through a rebalancing of benefits with the provincial Government. This could involve a temporary new financial arrangement for Conawapa. If properly designed this could lead to an economic case that is sufficiently beneficial to ratepayers to allow Conawapa to proceed. One such concept is illustrated in Section 6.3 of Appendix C: Results of InterGroup Financial Analysis to this submission.

4.4 OTHER COMMENTS

Hydro's NFAT also clarifies that DSM measures function in many ways as a complement to Pathways 3 and 4. As a result, concurrent with the above measures, Hydro should continue to pursue an aggressive program of DSM focused on securing all resources that can be brought on-line at a reasonable resource cost (PACT[58] test, or equivalent). This is a revision to the planning approaches presently used by Hydro for DSM, which seek to ensure the DSM measures (in combination, as part of a DSM plan) yield economic benefits to customers as well as Hydro. For various reasons, the approach used by Manitoba Hydro can result in a narrower DSM program than may otherwise be achieved by focusing primarily (if not solely) on the utility economics.

In addition, many conservation or energy efficiency/procurement measures that can yield power benefits to Manitoba Hydro are presently not pursued, and not included in DSM programming. This includes measures such as customer self-generation, an expanded Curtailable Rates Program, and export-oriented demand response options. These options should be prioritized by Hydro for inclusion in future DSM programming.

[57] Per 2013 planning assumptions.

[58] Program Administrator Cost Test, or a testing of whether the utility must pay more or less to secure DSM power than the power is worth to the system.

APPENDIX A

PATRICK BOWMAN'S UTILITY REGULATORY EXPERIENCE

InterGroup® CONSULTANTS

PATRICK BOWMAN
PRINCIPAL AND CONSULTANT

EDUCATION: **University of Manitoba**
MNRM (Natural Resource Management), 1998

Prescott College (Arizona)
BA (Human Development and Outdoor Education), 1994.

PROFESSIONAL HISTORY:

InterGroup Consultants Ltd. **Winnipeg, MB**

1998 – Present *Research Analyst/Consultant/Principal*

Project development, regulatory and rates, economic analysis and environmental licencing, primarily in the energy field.

Utility Regulation

Conducted research and analysis for regulatory and rate reviews of electric, gas and water utilities in six Canadian provinces and territories. Prepare evidence and review testimony for regulatory hearings. Assist in utility capital and operations planning to assess impact on rates and long-term rate stability. Major clients included the following:

- **For Yukon Energy Corporation (1998-present)**, analysis and support of regulatory proceedings and normal regulatory filings before the Yukon Utilities Board. Appear before YUB as expert on revenue requirement matters, cost of service, rate design, and resource planning. Prepare analysis of major capital projects, financing mechanisms to reduce rate impacts on ratepayers, depreciation, as well as revenue requirements.
- **For Yukon Development Corporation (1998-present)**, prepare analysis and submission on energy matters to Government. Participate in development of options for government rate subsidy programs. Assist with review of debt purchase, potential First Nations investment in utility projects, and corporate governance.
- **For Northwest Territories Power Corporation (2000-present)**, provide technical analysis and support regarding General Rate Applications and related Public Utilities Board filings. Assist in preparation of evidence and providing overall guidance to subject specialists in such topics as depreciation and return.

Appear before PUB as expert in revenue requirement, cost of service and rate design matters, and on system planning reviews (Required Firm Capacity).

- **For Manitoba Industrial Power Users Group (1998-present)**, prepare analysis and evidence for regulatory proceedings before Manitoba Public Utilities Board representing large industrial energy users. Appear before PUB as expert in cost of service and rate design matters. Assist in regulatory analysis of the purchase of local gas distributor by Manitoba Hydro. Assist industrial power users with respect to assessing alternative rate structures and surplus energy rates.
- **For Industrial Customers of Newfoundland and Labrador Hydro (2001-present),** prepare analysis and evidence for Newfoundland Hydro GRA hearings before Newfoundland Board of Commissioners of Public Utilities representing large industrial energy users. Provide advice on interventions in respect of major new transmission facilities. Appear before PUB as expert in cost of service and rate design matters.
- **For NorthWest Company Limited (2004-2006),** review rate and rider applications by Nunavut Power Corporation (Qulliq Energy), provide analysis and submission to rate reviews before the Utility Rates Review Council.
- **For Municipal Customers of City of Calgary Water Utility (2012-2013),** analysis of proposed new development charges and reasonableness of water and wastewater rates.
- **For Nelson Hydro (2013-current)**, development of a Cost of Service model.
- **For City of Swift Current (2013-current)**, utility system valuation approach.

Project Development, Socio-Economic Impact Assessment and Mitigation

Provide support in project development, local investment opportunities or socio-economic impact mitigation programs for energy projects, including northern Manitoba, Yukon, and NWT. Support to local communities in resolution of outstanding compensation claims related to hydro projects.

- **For Yukon Energy Corporation (2005-current),** Participated in preparation of resource plans, including Yukon Energy's 20-Year Resource Plan Submission to the Yukon Utilities Board in 2005 (including providing expert testimony before the YUB), advisor on 2010 update. Project Manager for all planning phases of the Mayo B hydroelectric project ($120 million project) including environmental assessment and licencing, preliminary project design, preparation of materials for Yukon Utilities Board hearing, joint YEC/First Nation working group on all technical matters related to project including fisheries, managing planning phase financing and budgets. Assistance in preparation of assessment documentation for Whitehorse LNG generation project.

- **For Northwest Territories Power Corporation (2010-current),** Participate in planning stages of $37 million dam replacement project; appear before Mackenzie Valley Land and Water Board (MVLWB) regarding environmental licence conditions; participate in contractor negotiations, economic assessments, and ongoing joint company/contractor project Management Committee. Provide economic and rate analysis of potential major transmission build-out to interconnect to southern jurisdictions. Conduct business case analysis for regulatory review of projects $400,000-$5 million, and major PUB Project Permit reviews of projects >$5 million.

- **For Northwest Territories Energy Corporation (2003-2005)**, provide analysis and support to joint company/local community working groups in development of business case and communication plans related to potential new major hydro and transmission projects.

- **For Kwadacha First Nation and Tsay Keh Dene (2002-2004):** Support and analysis of potential compensation claims related to past and ongoing impacts from major northern BC hydroelectric development. Review options related to energy supply, including change in management contract for diesel facilities, potential interconnection to BC grid, or development of local hydro.

- **For Manitoba Hydro Power Major Projects Planning Department (1999-2002)**, initial review and analysis of socio-economic impacts of proposed new northern generation stations and associated transmission. Participate in joint working group with client and northern First Nation on project alternatives (such as location of project infrastructure).

- **For Manitoba Hydro Mitigation Department (1999-2002)**, provide analysis and process support to implementation of mitigation programs related to past northern generation projects, debris management program. Assist in preparation of materials for church-led inquiry into impacts of northern hydro developments.

- **For International Joint Commission (1998)**, analysis of current floodplain management policies in the Red River basin, and assessment of the suitability of alternative floodplain management policies.

- **For Nelson River Sturgeon Co-Management Board (1998 and 2005)**, an assessment of the performance of the Management Board over five years of operation and strategic planning for next five years.

Government of the Northwest Territories **Yellowknife, NT**

1996 - 1998 *Land Use Policy Analyst*

Conducted research into protected area legislation in Canada and potential for application in the NWT. Primary focus was on balancing multiple use issues, particularly mining and mineral exploration, with principles and goals of protection.

PUBLICATIONS:

G*overnment Withdrawals of Mining Interests* in Great Plains Natural Resources Journal. University of South Dakota School of Law. Spring 1997.

Legal Framework for the Registered Trapline System in Aboriginal Trappers and Manitoba's Registered Trapline System: Assessing the Constraints and Opportunities. Natural Resources Institute. 1997.

Land Use and Protected Areas Policy in Manitoba: An evaluation of multiple-use approaches. Natural Resources Institute. (Masters Thesis). 1998.

Patrick Bowman Utility Regulation Experience

Utility	Proceeding	Work Performed	Before	Client	Year	Testimony
Yukon Energy Corporation	Final 1997 and Interim 1998 Rate Application	Analysis and Case Preparation	Yukon Utilities Board (YUB)	Yukon Energy	1998	No
Manitoba Hydro	Curtailable Service Program Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Manitoba Public Utilities Board (MPUB)	Manitoba Industrial Power Users Group (MIPUG)	1998	No
Yukon Energy	Final 1998 Rates Application	Analysis and Case Preparation	YUB	Yukon Energy	1999	No
Westcoast Energy	Sale of Shares of Centra Gas Manitoba, Inc. to Manitoba Hydro	Analysis and Case Preparation	MPUB	MIPUG	1999	No
Manitoba Hydro	Surplus Energy Program and Limited Use Billing Demand Program	Analysis and Case Preparation	MPUB	MIPUG	2000	No
West Kootenay Power	Certificate of Public Convenience and Necessity - Kootenay 230 kV Transmission System Development	Analysis of Alternative Ownership Options and Impact on Revenue Requirement and Rates	British Columbia Utilities Commission (BCUC)	Columbia Power Corporation/Columbia Basin Trust	2000	No
Northwest Territories Power Corporation (NTPC)	Interim Refundable Rate Application	Analysis and Case Preparation	Northwest Territories Public Utilities Board (NWTPUB)	NTPC	2001	No
NTPC	2001/03 Phase I General Rate Application	Analysis and Case Preparation	NWTPUB	NTPC	2000-02	No - Negotiated Settlement
Newfoundland Hydro	2002 General Rate Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Board of Commissioners of Public Utilities of Newfoundland and Labrador (NLPUB)	Newfoundland Industrial Customers	2001-02	No
NTPC	2001/02 Phase II General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2002	Yes
Manitoba Hydro/Centra Gas	Integration Hearing	Analysis and Case Preparation	MPUB	MIPUG	2002	No
Manitoba Hydro	2002 Status Update Application/GRA	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2002	Yes
Yukon Energy	Application to Reduce Rider J	Analysis and Case Preparation	YUB	Yukon Energy	2002-03	No
Yukon Energy	Application to Revise Rider F Fuel Adjustment	Analysis and Case Preparation	YUB	Yukon Energy	2002-03	No
Newfoundland Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2003	Yes
Manitoba Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2004	Yes
NTPC	Required Firm Capacity/System Planning hearing	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2004	Yes
Nunavut Power (Qulliq Energy)	2004 General Rate Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission (URRC)	NorthWest Company (commercial customer intervenor)	2004	No
Qulliq Energy	Capital Stabilization Fund Application	Analysis, Preparation of Intervenor Submission	URRC	NorthWest Company	2005	No
Yukon Energy	2005 Required Revenues and Related Matters Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2005	Yes
Manitoba Hydro	Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2006	Yes
Yukon Energy	2006-2025 Resource Plan Review	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2006	Yes
Newfoundland Hydro	2006 General Rate Application	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2006	No - Negotiated Settlement
NTPC	2006/08 General Rate Application Phase I	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2006-08	Yes
Manitoba Hydro	2008 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Manitoba Hydro	2008 Energy Intensive Industrial Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Yukon Energy	2008/2009 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2008-09	Yes
FortisBC	2009 Rate Design and Cost of Service	Analysis and Case Preparation	BCUC	BC Municipal Electrical Utilities	2009-10	No
Yukon Energy	Mayo B Part III Application	Analysis, Preparation of Company Evidence	YUB	Yukon Energy	2010	No
Yukon Energy	2009 Phase II Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2009-10	Yes
Newfoundland Hydro	Rate Stabilization Plan (RSP) Finalization of Rates for Industrial Customers	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2010	Pending
Manitoba Hydro	2010/11 and 2011/12 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2010-11	Yes
NTPC	Bluefish Dam Replacement Project	Analysis, Preparation of Company Evidence and Expert Testimony	Mackenzie Valley Land and Water Board	NTPC	2011	Yes
NTPC	2012/14 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2012	Yes
Manitoba Hydro	2012/13 and 2013/14 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2013	Yes

APPENDIX B

ECONOMIC ANALYSIS CRITIQUE

APPENDIX B – ECONOMIC ANALYSIS CRITIQUE

This appendix addresses a review of Hydro's Economic Analysis contained in the NFAT. It is organized into the following sections:

1) Theoretical Basis for Utility Economic Analysis;
2) Hydro's Economic Analysis Approach;
3) InterGroup's Concerns With Hydro's Approach; and
4) Approaches to Address Issues.

Based on the discussion in this Appendix, InterGroup focused its primary efforts on Hydro's NFAT financial analysis rather than the economic analysis. The detailed results of that review are set out in Appendix C: Results of InterGroup Financial Analysis.

1.0 THEORETICAL BASIS FOR UTILITY ECONOMIC ANALYSIS

Economic project modelling is a standard utility practice, though there is typically some variation in the specific methods applied among different utilities given unique system configurations.

Any form of economic modelling provides forecast strings of future costs and benefits. It is necessary to resolve or convert these strings of variables to individual numbers for better comparability, and to reflect that results occurring later in time may be less important than those occurring earlier in time, for various reasons. To permit analysis of these values, the technique of "discounting" is used to achieve a Net Present Value ("NPV").

Discounting is inherently only an analytical tool. To complete a discount analysis, one must identify the appropriate discount rate to be used. In academic, policy, or technical venues there can be much debate about the proper discount rate to be used. This is in part because a discount rate can capture two different concepts:

1) **The cost of money/capital:** One approach to developing a discount rate is to focus on the cost of money. For example, most corporate environments will value future revenues or costs at a rate that represents what their capital (debt or equity) costs. Included in this rate is a concept

of risk, i.e., how much should the debt or equity cost given the degree of project risk, as well as financing risk[1]. Hydro has justified each of its discount rates on this basic rationale:

a. Hydro has applied a 5.05% real discount rate to Reference-case economic analysis (2012; for 2013 updates Hydro applies a 5.4% real discount rate) based on the cost of debt, a notional cost of equity, and an assumed appropriate mix between the two. Higher and lower discount rates are used to represent scenarios where the cost of capital (interest rate on debt) varies from the Reference level.

b. Hydro has also used this cost of money based rationale to discount ratepayer impacts in PUB/MHI-149(a) at a real discount rate of 1.86%, based on a premise that the ratepayers' cost of money (in this case foregone investment in Short-Term Canadian T-Bills) is 3.8% nominal, or 1.86% real (i.e., after inflation is taken into account).

c. In the Chapter 13 Multiple Account Analysis Hydro uses a 6.0% real discount rate on the basis that this is a reasonable "social opportunity cost of capital" which is "calculated by weighting and then summing the cost of the different potential sources of capital: savings, borrowing from outside the jurisdiction, and displacement of other investments"[2].

At the same time as Hydro's analysis may reflect the Hydro corporate cost of capital, other parties which experience different impacts may have their own cost of money/capital considerations. For example, for a ratepayers paying higher rates in the first 20 years, for the purpose of achieving lower rates in the period after 20 years, there would be a cost to this "investment". The cost would reflect the competing use or source of funds. For example, for a firm that has alternative investment opportunities, the competing uses for capital may have high expectations, even on a risk adjusted basis[3].

2) **The time preference for money:** Discount rates do not always represent a specific identifiable cost of capital. The discount rate concept is much broader – it is a comprehensive concept of the time preference for money. It is a subjective concept that can be unique to each individual, firm, government and can even vary between different scenarios or investment opportunities. Even a "social" discount rate that represents some aggregated societal view of time preference will fail to reflect that there can be individuals who are exceedingly short-range focused (high priority for current period resources). This may include individuals who are poor, or firms who are optimistic

[1] For example, debt:equity ratio.

[2] NFAT Chapter 13 Footnote 7.

[3] Investments that have risk may be required to pass a corporate hurdle rate of, say, 12-15% or more depending on the risk; for a lower risk investment the corporate threshold rates may be lower, but still much higher than the rates applied by Hydro.

about expansion of their core business[4]. In contrast, there may well be other individuals who are much more long-term focused, which could be consistent with concepts of leaving a 'legacy' or a strong sense of stewardship. At times, some parties may have differing time preferences for different opportunities. A shorter-term focus is consistent with a higher discount rate, while long-term focus is consistent with a low discount rate.

In summary, the discount rate encompasses the concept of cost of capital, but is fundamentally broader. The cost of capital is an attempt at a projection – 'what will be the correct costs that the utility incurs for money in the future?' There is a correct, but presently unknown, value. The time preference for money is different. There is no 'right' current or future answer. It is not a projection but a preference. It may change over time, but the analysis should not be considered an attempt at projecting the correct future value, but at capturing the range of valid present perspectives. For this reason, **project analysis should provide for assessments to be completed at varying discount rates which do not solely reflect changes in the underlying cost of money.**

In addition to the general time preference for money, there can be a benefit to considering NPVs calculated over a horizon that is shorter than the full forecast scenarios (effectively applying a 100% discount rate to later periods). This approach can be a coarse tool to reflect either severe uncertainty with the results in the very long horizon, or to reflect practical limits on an individual's horizon of concern. For example, Hydro's economic analysis reflects values over 78 years, while the financial analysis terminates at 50 years. For many ratepayers, analysis that terminates at a different horizon (e.g., only reflect the impacts of the scenario over the first 20 or 30 years) may be valuable.

2.0 HYDRO'S ECONOMIC ANALYSIS APPROACH

Hydro's economic analysis focuses on converting a series of values (in real dollars) to a single NPV for the entire scenario. The analysis is designed to compare different plans (15 Plans) under different sensitivity scenarios (27 Scenarios). The economic analysis (including the detailed forecasts provided in NFAT Appendix 9.3) has the following characteristics:

[4] In contrast to the strict cost of capital, some corporate investments, such as capital investments in facility improvements, may have exceedingly high effective discount rates represented by the simpler concept of "payback"; that is, the investment may have to pay for itself in full in, say, 2-3 years. That may be consistent with a 30-50% rate of return or higher – and this may be applied to even low risk internal projects. These thresholds may be applied even where the corporate cost of capital is much lower than this level. In pure economic terms, such thresholds may be viewed as theoretically inconsistent, but in practice they are a normal part of corporate planning.

- **Cash-flow based capital:** For capital spending Hydro's economic model includes the annual outflows on capital spending in a given year, plus capital taxes and fixed O&M (including capital replacements)[5].

- **Models Full SPLASH variables**: The model also provides the annual "Net Revenue" as this term is used in the SPLASH modelling[6], which includes all export revenue (not just that arising from the capital projects built under the specific scenario), all fuel and purchased power for the utility, and all water rentals for all plants combined (new and existing). The value reported is the mean of all water flow scenarios. In this manner, the Net Revenue value reported has effectively no *absolute* inherent meaning (i.e., it is not the net income for the utility[7], nor is it the export revenues due to a particular project, nor is it the net profits from all export activity[8], etc.) such that any single value is not meaningful unless compared against another plan or scenario[9].

- **Models long-term horizon plus salvage value:** Hydro's economic models provide an NPV over a very long horizon. This consists of a 35 year detailed evaluation followed by a broader long-life evaluation beyond this period. In addition a Salvage value is used for periods beyond 78 years which represents "The economic value of an asset at the end of the study period based on the original capital expenditures, service life, and in-service years (the period between the in-service date and the end of the study period)"[10]. The salvage value serves to reduce the 78 year NPV of costs in recognition of a residual or future value of the remaining facilities that occurs beyond 78 years.

- **Can't separate discount rate from real interest rates:** Hydro has modelled the economics in a manner that can only reflect interest rates on debt through the discounting rate for present values. This means that there is no ability to independently test variations in discount rate within a desirable range.

    - One effect of this issue is that no analysis can be performed under an expectation that interest rates will be within the range selected by Hydro, but with a different judgment on the time preference.

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[5] While this concept is sometimes termed a "cash flow" model, it is somewhat of a misnomer as the cash outflows noted for capital spending would in practice be met with cash inflows from borrowings to pay these capital costs – it is the principal and interest payments on debt that would represent the true net cash transaction, but such analysis is only conducted in Hydro's financial models.

[6] NFAT Appendix 9.3 page 87.

[7] Net income requires consideration of domestic revenues, interest costs, etc. which are not modeled.

[8] The Net Revenue value includes, for example, all water rentals whether for export or domestic activity.

[9] For example see Manitoba Hydro's 2010/11 and 2011/12 General Rate Application transcript regarding testimony of Mr. Harmond Surminski under cross-examination from Mr. Antoine Hacault, page 5628 (April 14, 2011)

[10] NFAT Glossary page x.

- The more substantive issue is that one cannot keep the discount rate the same, but only vary the real interest rate. This is further addressed below.

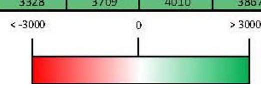
- **Costs only include direct costs:** Hydro's economic analysis includes basically all corporate cash outflow costs that vary between the different scenarios for the bulk power system. There is no reflection of the "costs" borne by ratepayers related to building up needed reserves as these are an indirect concept (a required difference in net income to build reserves (such as a 75:25 debt:equity) are not included). There is also no reflection of the beneficiary in the scenarios, to the extent that this beneficiary may be, for example, First Nation partners as opposed to ratepayers. There is also no reflection of indirect corporate costs needed to support large scale resource development. It is understood that these costs would no longer be tracked to the projects under IFRS, and as such will not show up in the Economic Analysis.

Manitoba Hydro's Economic Analysis allows generation of NPVs that can be compared to determine economic preferences. The underlying presentation of these results is provided in the NFAT Business Case (the "quilts"), which are further discussed below with respect to interpretation of the quilts and limitations regarding what they show. For reference, Hydro's two quilts are shown below as Figure 1 and Figure 2.

Figure 1: Hydro's Table 10.5 from NFAT Business Case: Quilt Relative to All Gas Ref-Ref-Ref[11]

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		
Energy Prices	Discount Rates	Capital Costs	Millions of 2014 NPV dollars												Probabilities
Low	Low	H	-4043	-7769	-3309	-3792	-3190	-3459	-3506	-3418	-3642	-3554	-2855	-2841	1.35%
		Ref	-3049	-5403	-2401	-2532	-1877	-2124	-2166	-2130	-2177	-2138	-1616	-1410	2.25%
		L	-2247	-3666	-1655	-1590	-890	-1069	-1099	-1175	-1030	-1022	-703	-292	0.90%
	Ref	H	-463	-3056	-1297	-1212	-911	-2510	-2161	-1191	-2816	-2323	-730	-2155	4.50%
		Ref	208	-1478	-582	-278	95	-1368	-1050	-185	-1559	-1153	257	-929	7.50%
		L	750	-323	6	408	837	-473	-176	548	-585	-243	974	20	3.00%
	High	H	1204	-796	-284	25	117	-2029	-1413	-182	-2383	-1622	203	-1810	3.15%
		Ref	1708	384	323	785	963	-994	-434	679	-1243	-592	1060	-698	5.25%
		L	2114	1245	822	1336	1580	-189	327	1297	-364	201	1674	157	2.10%
Ref	Low	H	-5014	-7167	-1760	-2511	-1796	206	-334	-2041	498	0	-2103	853	2.48%
		Ref	-4020	-4802	-852	-1251	-482	1541	1006	-753	1963	1415	-865	2284	4.13%
		L	-3217	-3064	-107	-309	504	2597	2073	202	3110	2531	49	3402	1.65%
	Ref	H	-671	-2354	23	-46	341	152	104	85	170	190	109	470	8.25%
		Ref	0	-775	738	887	1346	1295	1215	1091	1427	1360	1097	1696	13.75%
		L	542	380	1326	1573	2089	2189	2089	1824	2401	2270	1813	2645	5.50%
	High	H	1308	-82	879	1091	1258	109	391	998	2	366	1041	268	5.78%
		Ref	1812	1098	1487	1851	2104	1144	1370	1859	1143	1396	1898	1380	9.63%
		L	2218	1959	1986	2402	2721	1949	2132	2478	2022	2189	2512	2235	3.85%
High	Low	H	-6435	-6719	-355	-1499	-692	3819	2796	-1006	4455	3410	-1694	4372	0.68%
		Ref	-5441	-4353	552	-239	621	5154	4135	282	5921	4826	-456	5803	1.13%
		L	-4638	-2616	1298	703	1607	6210	5203	1237	7068	5941	458	6922	0.45%
	Ref	H	-1158	-1767	1241	941	1398	2746	2308	1127	2993	2571	713	2940	2.25%
		Ref	-487	-189	1956	1874	2403	3888	3420	2134	4250	3741	1701	4166	3.75%
		L	55	966	2543	2560	3146	4783	4293	2867	5225	4652	2417	5115	1.50%
	High	H	1210	533	1956	2017	2246	2170	2127	1993	2236	2228	1691	2203	1.58%
		Ref	1713	1712	2563	2777	3092	3206	3106	2854	3377	3259	2549	3315	2.63%
		L	2120	2573	3063	3328	3709	4010	3867	3473	4256	4051	3163	4170	1.05%

Colour Legend



[11] Manitoba Hydro NFAT Business Case, Chapter 10, Table 10.5, page 17 (August 2013).

Figure 2: Hydro's Table 2 from NFAT Business Case: Quilt Relative to All Gas[12]

Pathway			Pathway 1			Pathway 2		Pathway 3			Pathway 4			Pathway 5	
Development Plan			1	7	8	2	10	4	13	11	6	15	12	5	14
			All Gas	SCGT/C26	CCGT/C26	K22/Gas	K22/C29	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	
Energy Prices	Discount Rates	Capital Costs	Millions of 2014 NPV dollars												
Low	Low	H	0	734	514	251	-22	853	584	537	625	401	489	1188	1202
		Ref	0	648	567	517	263	1172	925	883	919	872	911	1433	1639
		L	0	592	620	657	474	1357	1178	1148	1072	1217	1224	1544	1955
	Ref	H	0	-834	-1068	-749	-2076	-448	-2047	-1698	-729	-2353	-1861	-267	-1692
		Ref	0	-790	-913	-487	-1704	-114	-1576	-1258	-393	-1768	-1362	49	-1137
		L	0	-744	-779	-342	-1428	87	-1223	-926	-202	-1335	-993	224	-730
	High	H	0	-1488	-1721	-1179	-2863	-1087	-3233	-2617	-1386	-3587	-2826	-1001	-3014
		Ref	0	-1385	-1521	-923	-2462	-744	-2701	-2141	-1029	-2950	-2299	-648	-2406
		L	0	-1292	-1352	-778	-2165	-534	-2303	-1787	-817	-2478	-1914	-440	-1958
Ref	Low	H	0	3253	3310	2502	4174	3218	5220	4680	2973	5511	5013	2910	5866
		Ref	0	3167	3364	2768	4458	3537	5561	5026	3267	5983	5435	3155	6304
		L	0	3111	3417	2908	4669	3721	5814	5291	3420	6327	5749	3266	6620
	Ref	H	0	694	628	625	434	1012	823	775	756	841	861	780	1141
		Ref	0	738	784	887	806	1346	1295	1215	1091	1427	1360	1097	1696
		L	0	784	917	1031	1083	1547	1648	1547	1282	1860	1729	1272	2103
	High	H	0	-429	-544	-218	-1140	-50	-1199	-917	-310	-1306	-942	-268	-1040
		Ref	0	-325	-344	39	-739	292	-668	-441	47	-669	-416	86	-432
		L	0	-233	-175	184	-441	503	-269	-87	259	-196	-30	294	16
High	Low	H	0	6079	6411	4936	8790	5742	10254	9230	5428	10890	9844	4740	10807
		Ref	0	5993	6465	5202	9074	6062	10595	9576	5722	11361	10266	4985	11244
		L	0	5937	6518	5342	9285	6246	10849	9841	5875	11706	10580	5096	11560
	Ref	H	0	2398	2494	2099	3172	2556	3903	3466	2285	4151	3729	1871	4098
		Ref	0	2442	2649	2361	3543	2890	4375	3906	2620	4736	4228	2187	4653
		L	0	2489	2783	2505	3820	3091	4728	4238	2812	5170	4597	2362	5060
	High	H	0	747	742	807	725	1036	961	917	783	1027	1019	482	994
		Ref	0	850	942	1064	1126	1379	1492	1392	1141	1664	1546	835	1602
		L	0	943	1111	1208	1424	1589	1891	1747	1353	2136	1931	1043	2050

Colour Legend <-3000 0 >3000

As noted above, the values arising from the economic analysis are not inherently meaningful. They are only meaningful in relation to values arising from the other plan scenarios. Two different approaches for "indexing" the quilts lead to two different presentations. The first (Figure 1) shows the NPV value indexed to the Plan 1 (All Gas) REF-REF-REF, and the second (Figure 2) shows the same value indexed to the Plan 1 (All Gas) value for the same scenario (e.g., Plan 14 (PDP) NPVs for the LOW-LOW-LOW scenario are indexed to the Plan 1 (All Gas) LOW-LOW-LOW in Figure 2).

Hydro utilizes the quilts in two different ways:

1) **Identify best Plans under a given set of conditions (Figure 2 above):** The first use of the quilt is by comparing row values under a scenario analysis (or what Hydro has termed a "regret" analysis)[13]. For example, comparing across a row can answer the question 'if a given set of future

[12] Manitoba Hydro NFAT Business Case, Executive Summary, Table 2, page 23 (August 2013).

[13] The term "regret" is first presented in response to MIPUG/MH-I-9(a). Technically the NFAT Business Case Table 2 (from the Executive Summary), shown above as Figure 2, is not necessarily a regret framework for decision, as it is simply a presentation of values. A regret-based decision would only arise if one took this quilt of values and made a decision about which plan to pursue based on avoiding future "regret" (meaning attempts to avoid a finding in future that All Gas would have been a better selection than the one made) regardless as to likelihood of future benefits. For example, it would be based on selecting either (a) the plan with the least *likelihood* of being worse than gas (number of times, out of 27 scenarios, that All Gas would have been better), or (b) the plan with the smallest worst case *loss* or the single potential outcome in future that is worse than All Gas under the least favourable future conditions (i.e., find the largest negative value on each row in Figure 2 and pick the plan with the smallest of these values). InterGroup is not advocating this method of selecting the Plan to pursue.

conditions arise, would Plan 14 (PDP) be better than Plan 1 (All Gas)?' Subject to limitations this use of Figure 2 above is appropriate for this task.

2) **Variations of different Plan performance under varying conditions:** Hydro relies heavily on the values in Figure 1 above, which it terms the "utilitarian" approach[14]. These values are used throughout Chapters 9 and 10 of the NFAT Business Case as well as Appendix 9.3 to generate the comparisons and the "S-curves" which are presented to assess the risks of each plan. This use of the quilt is problematic.

3.0 INTERGROUP'S CONCERNS WITH HYDRO'S APPROACH

There are four concerns that InterGroup has identified with the economic modelling completed by Hydro. By far, the first concern below is the most substantive:

1) **Variations in real interest rate skews values:** The most substantive concern with Hydro's analysis is that it provides no ability to separate the selection of a real interest rate from the selection of a discount rate. When Hydro models a varying real interest rate, the mechanics applied are a change to the discount rate used to calculate NPVs. This leads to two major issues:

   a. Changes in the discount rate serve to change the present value of all costs in the economic analysis. As the Economic analysis is based on SPLASH output values, which are related to both the existing system and the system additions, there is an inherent revaluation of many key variables that have nothing to do with the development plan. For example, the SPLASH output includes water rentals paid in respect of existing hydro generation such as Limestone or Pointe du Bois. These costs are largely unaffected by any of the development scenarios, but the NPV of these costs are materially changing as the different future interest rates are modelled. This is not inherently incorrect *per se*, but it leads to a substantive limitation on the quilt data – that is, the quilts cannot be compared across multiple rows where the discount rates (interest rates) are varied. The quilt results do not provide for any meaningful interpretation of the risks of changes in the level of real interest rates. Comparing any given row is fine (as is done with Figure 2.7.2) but comparing values from different rows that do not have matching interest/discount rates is not valid.

   b. As a result of the above limitation, Hydro's generation of S-curves (which inherently compares across all rows for each plan) is fundamentally flawed. The best illustration of this effect is by looking at specific values in the reproduced Figure 1 and Figure 2 above.

[14] MIPUG/MH-I-9(a).

i. The middle row of the quilt is the REF-REF-REF scenario, which represents the baseline or "most likely" forecast conditions. Looking at Figure 2 above, the last column shows Plan 14 (PDP) at **$1.696 billion better than Plan 1** (All Gas). Looking up 3 rows, to the REF-LOW-REF scenario row (the situation with reference capital costs and energy prices, but low interest/discount rates) the PDP is now **$6.304 billion better than Plan 1** (All Gas). This is an entirely expected intuitive outcome, as hydraulic resources are generally thought to be capital intensive, and aided by lower interest rates.

ii. To understand what is happening in the numbers, it is necessary to look at Figure 1 above. In that figure, the same $1.696 billion is shown for the REF-REF-REF scenario for Plan 14 (PDP). As this table is indexed Plan 1 (All Gas) REF-REF-REF, the value for Plan 1 on this row is $0. Looking up 3 rows again, the table shows a Plan 14 (PDP) NPV that is $2.284 billion. This is **an improvement over the REF-REF-REF conditions of $0.588 billion**. The Plan 1 results, however, show a difference of negative $4.020 billion from $0 the REF-REF-REF scenario. This is **an erosion of benefits compared to REF-REF-REF of $4.020 billion**[15]. (Note that the sum of the two NPVs yields the $6.304 billion result noted above).

iii. Hydro presents this quilt intended to measure the absolute increase or decrease in wealth[16]. The Plan 1 (All Gas) case illustrates why this is flawed – The model indicates that if Hydro elects for an All Gas future, and ultimately the world is faced with low real interest rates, that Manitobans will be substantially *less wealthy* than if normal interest rates arise. This outcome is nonsensical as all plans require debt for financing and low real interest rates are better than normal or high interest rates for utility plans with debt financing.

iv. More importantly, this analysis suggests that the selection of a gas generation future, where Manitobans must invest only $6.862 billion[17] (2014$) in new assets

[15] In practice, the detailed mathematics further underline the conclusion above. In particular, the change in the NPV for the Plan 1 (All Gas) case is not due to any capital asset or interest financed investment. The change is mostly due to the revaluation of future export revenues, and the revaluation of future fuel and purchased power costs. In short, the effect of the economic modeling sensitivity to interest rate risk is very little impact on the capital assets that are debt financed themselves. It is a net impact on the other variables unrelated to debt that largely change the above numbers. As noted above, this is not inherently incorrect – the $6.304 billion value is a valid interpretation of the NPV spread between the two cases. What is not valid is to conclude that the Plan 1 (All Gas) is more subject to interest rate risk than Plan 14 (PDP).

[16] MIPUG/MH-I-009(a).

[17] The sum of the Total Capital column in Plan 1 (All Gas) REF-REF-REF in NFAT Appendix 9.3.

over 78 years[18], drives *much more* sensitivity and risk to interest rates than the selection of a hydro generation future where Manitoba must invest $12.384 billion[19]. This is not a reasonable conclusion. This flaw carries into effectively all Hydro generated S-curves and box-and-whisker plots. As an extreme example, if there were an option that required a $100 billion investment very soon (which would clearly be debt financed) Hydro's analytical approach would suggest there is no risk related to real interest rates from this spending, which is not reasonable.

In short, the problem of Hydro's design of the economic analysis is twofold. First, one cannot vary the interest rate to test each plan's sensitivity to interest rates in a consistent manner (without the changes to the discount rate skewing the conclusions). Second, one cannot vary the discount rate to test a range of sensitivities without also changing the interest rate, which undermines the purpose of proper discount rate sensitivity analysis.

2) **Unable to consider alternative horizons:** The approach used by Hydro, which includes all spending on capital projects in the year incurred, prevents any ability to analyze the various Plans or Scenarios over anything less than the full 78 year horizon.

3) **Ignores reserves:** The approach to economic analysis can indicate if a given plan will generate positive economic results over its life, but it cannot indicate if those positive results will be anywhere near sufficient to generate the needed reserve levels for the larger plans that are based on added hydro generation. These reserves (e.g., debt:equity ratios) are an integral component to the costs of new facilities as they are required to address such issues as exposure to low water, which is increased by the construction of added hydro facilities. Additionally, Hydro's financial target of 75:25 debt:equity ratio requires very large investments into reserves for the plans that include hydro generation in the next decade, which is a strain on ratepayers. For this reason, even a Plan that has a positive economic analysis over another Plan may never translate to actual lower rates for ratepayers as the economic benefits may be arising for other stakeholders. This effect is not captured in the economic analysis[20].

4) **Average water flow scenarios too early in analytical process:** The last but far less substantive concern is that Hydro appears to use mean SPLASH results to model each of the 27 Scenarios, then uses the 27 data points to draw risk-based S-curves and box-and-whisker plots.

[18] Much of this investment is in the later years of the NFAT timeframe.

[19] $12.384 billion per the Total Capital column of Plan 14 (PDP) REF-REF-REF in NFAT Appendix 9.3. Much of this investment is in the early years where it is typically more of an impact on NPVs.

[20] Similarly, the economic analysis also fails to represent the impacts on ratepayers in that it does not reflect the sharing of aspects of the economic benefits with First Nations.

A more fulsome presentation of the data would generate 99 economic projections for each Scenario based on each of the water flow variations, then model the S-curves (e.g., P10, P90 values) based on the full 27x99 data sets. This would not be expected to effect the REF-REF-REF scenario or Expected Value (EV) results, but it may lead to a more fulsome picture of the true range of the more outlier "tails" (P10 and P90 values). Although this is not something that must be corrected, it may be considered by Hydro as a possible future improvement on the economic modelling.

As a result of these issues, there is a need for caution with various conclusions in Hydro's NFAT Business case. For the most part, Hydro's economic analysis of the REF-REF-REF conditions is mathematically accurate when assessing the long-term but cannot be done for periods less than the full 78 years. The reported results for modelling of the LOW and HIGH conditions for capital costs and for energy prices are also mathematically accurate (but limited to long-term horizons under a single discount rate and interest rate assumption). However, Hydro's approach to modelling risks related to changes in real interest rates is not reliable and should not be used as a basis for determining the best development plan.

As a result, Hydro's conclusions about risk that are based on the economic modelling (in particular the S-curves, box-and-whisker plots, scatter plots) are therefore not reliable, particularly in regard to Plan 1 (All Gas).

4.0 APPROACHES TO ADDRESS ISSUES

There are effectively three ways that the above weaknesses can be addressed:

1) **Rely solely on Figure 2 (Hydro's Table 2) results:** It is possible, though inferior, to conduct the NFAT analysis solely on the basis of Figure 2 (Hydro's Table 2 in the Executive Summary) above and ignore all results stemming from Figure 1 (Hydro's Table 10.5 from Chapter 10 of the NFAT Business case) values (including S-curves, box-and-whisker plots, etc.). This approach may be able to lead to good decisions based on the perspective that one does not know what the future will be, or even how variable the future results may be, but a given plan can be selected if, regardless as to the future that arises, it always (or almost always) dominates, or is a better outcome than the other options presented. Unfortunately, under relatively complex decisions such as the NFAT review, a purely dominant plan is rarely encountered, so this approach is unlikely to be sufficient. This is illustrated in Figure 2 by the lack of any column that contains all positive or all negative numbers. This approach also gives rise to concerns over evolving into a pure "regret" analysis as the basis for decision-making, which is not ideal as was well explained by Hydro in MIPUG/MH-I-9(a) and MIPUG/MH-II-4(a).

2) **Convert capital costs of projects to a form of levelized Unit Energy Costs (UECs):** This approach resolves a number of the above issues by converting the capital costs of each project from a cash flow value as of the years of construction into a levelized UEC for each year the project is in service, using a specified interest rate/cost of capital[21]. The revised scenario can then be discounted using a selected discount rate separate and independent from the interest rate selected. While the discount rate may be the same as the cost of capital used, it does not necessarily have to be so (and in fact it would not be for any given S-curve). This approach would resolve a number of the above concerns:

- It permits the discount rate to be fixed, while the interest rate can vary to assess risks. This permits consistent reliable S-curves to be plotted.
- It permits the discount rate to vary, while the interest rate is held constant. This permits analysis of sensitivities from the perspective of time preference separate and apart from market costs/expectations.
- It permits analysis to be conducted on shorter time horizons if so desired, e.g., terminating at 20 or 30 years to determine if this changes the conclusions regarding the optimum Plan.

Despite these benefits, there are limitations to the UEC approach in terms of departing from a proper cash flow analysis (the UEC is not a cash flow concept). While many utilities do use the UEC type approach, this is often for specific reasons that are not relevant to Manitoba Hydro, for example comparing projects with different proponents who have different underlying costs of capital, or for supply sources such as IPPs which have a given contract termination date.

3) **Move the focus to the Financial Analysis (Chapter 11) and use the values presented there for discounting and NPVs:** Unlike the economic analysis in Chapter 9 and 10, the financial analysis in Chapter 11 is not burdened by the above issues as follows[22]:

- Interest rates can be modelled separately from discount rates;
- Provides for the costs associated with setting aside reserves to be reflected as an adverse aspect of larger developments;
- Allows for shorter horizons to be modelled; and

[21] This is similar to the approach used by BC Hydro in its Resource Planning and project analysis.
[22] Chapter 11 still uses mean water flows rather than all water flows, but as noted above this is a possible future improvement not an inherent flaw in the current analysis.

- Can be directed to specifically focus on ratepayers, separating out the expected benefits that ultimately go to First Nations, to Government, or that stay within Manitoba Hydro to grow reserve levels.

There are a few downsides to the financial approach as compared to the economic approach, namely: (a) not all Plans are modelled through the financial analysis, and (b) the horizon is at most limited to 50 years. Neither of these limitations are excessively problematic for the NFAT review.

Based on the above, InterGroup has focused efforts on analysis of the financial model outputs.

As part of NFAT hearing coordination, complementary work is understood to be underway by Mr. Bill Harper from Consumers' Association of Canada (CAC) focused on revising Hydro's economic analysis to try to address some of the above issues.

APPENDIX C

RESULTS OF INTERGROUP FINANCIAL ANALYSIS

APPENDIX C – RESULTS OF INTERGROUP FINANCIAL ANALYSIS

This appendix reviews Hydro's Financial Analysis contained in the NFAT and provides the results of InterGroup's assessment. The appendix relies primarily on Manitoba Hydro's Appendix 11.4: Pro Forma Financial statements and much of the same methodology described in Appendix 9.3: Economic Evaluation Documentation to analyze the effects of Manitoba Hydro's Plan 14 (Preferred Development Plan or "PDP" consisting of Keeyask in 2019/20, Conawapa in 2025/26, followed by natural gas-fired generation, 750MW Import/Export US Interconnection in 2020/21, 250 MW MP sale, Proposed 300 MW WPS Sale and investment) and alternative resource plans on domestic ratepayers and the Government of Manitoba.

This Appendix is organized into the following sections:

1) Approach Methodology;
2) Financial Analysis Results – Waterfall Graphs;
3) Financial Analysis Results – 50 Year "Quilt" Presentation;
4) Ratepayer Risks and "Cone" Graphs;
5) Government Benefits; and
6) Ratepayers Discount Rate Sensitivities

InterGroup has focused its efforts on Hydro's NFAT financial analysis as detailed in this Appendix.

1.0 APPROACH METHODOLOGY

InterGroup focused the bulk of review on the Financial Analysis portion of Manitoba Hydro's NFAT. This is for the following reasons:

1) **Address Concerns:** As set out in Appendix B: Economic Analysis Critique, upon review of Hydro's NFAT Economic Analysis, there appeared to be a basis for concern in the ability of Hydro's approach to review and compare the returns and the risks of plans under varying interest rates/economic conditions[1]. This same concern is not inherently present in the NFAT Financial Analysis.

[1] Hydro's Scenario for this variable is in fact somewhat more comprehensive than just real interest rates, as it includes inflation and other economic indicators.

2) **Horizon:** Hydro customers require consideration of financial effects over both short-term and long-term scales; the economic analysis only has the ability to evaluate plans over the entire 78 year horizon effectively.

3) **Ratepayer Context:** The financial analysis provides the revenues and costs for the existing system as well as the potential development plans and therefore gives a better sense of the entire picture on ratepayers in the future. The economic analysis focuses on incremental costs and benefits as a result of each plan, but does not fully incorporate the underlying existing system[2]. Since Manitoba Hydro's future developments will be integrated into an existing system, it is important to look at the total effects on ratepayers. In addition, sunk costs are not included in the economic analysis. While this is appropriate for economic analysis, in reality, these costs are spent but have yet to be collected through rates and need to be considered when assessing impacts on customers.

4) **Varying Discount Rates:** As addressed in Appendix B: Economic Analysis Critique, proper resource analysis requires an ability to vary a discount rate to be able to test the sensitivity of a project decision to the discount rate assumed (separate and apart from assessing risks related to interest rates). In the economic analysis it is not possible to independently vary the discount rate except as a function of underlying changes in the economic conditions such as interest rates.

The financial analysis data of Manitoba Hydro's development plans have been assessed using the following approach:

- **Data Source:** The primary financial data relied upon was provided in Appendix 11.4 of the NFAT filing. This data was compiled comparing the financial benefits of each development plan ("Plan") under each sensitivity scenario developed by Hydro ("Scenario"). Financial data was provided for Plans 1 (All Gas), 2 (K22/Gas), 4 (K19/Gas/250MW), 6 (K19/Gas/750MW), 7 (Gas/C26), 12 (K19/C31/750MW), 13 (K19/C25/250MW) and 14 (PDP).
    - InterGroup understands that Manitoba Hydro's financial data is provided for their fiscal year beginning in April of each year. Data is presented at year end of each financial year so for the year labelled 2013 (the first year given in the Appendix 11.4 spreadsheets), the dollar value is provided is for the 2012/13 fiscal year, and balance sheet values for March 2013.

[2] This limitation is not due to any flaw of Hydro's economic analysis approach, it is just an inherent limitation of utility project economic analysis.

- Simple Net Present Value (NPV) calculations typically discount the first year in a sequence by one year (i.e., discount the first values in Hydro's spreadsheet to 2011/12 or March, 2012 dollars). To present a dollar value at the time of Manitoba Hydro's key decisions (mid-way through the 2014/15 year) as well to best compare with the Economic data which has a June 2014 time, the standard NPV calculations were escalated three years.

- **Debt Guarantee Fees:** Debt guarantee fees are not explicitly provided in Appendix 11.4. However, debt guarantee fees were provided in Attachment 1 of PUB/MH I-073a. This data was incorporated into the financial data for each Plan and Scenario. Debt guarantee fees paid were adjusted out of the interest costs otherwise recorded in Appendix 11.4. There is a small disconnect that may arise from this approach, related to debt guarantee fees paid to the province in a given year for projects under construction, but ultimately capitalized in Hydro's financial statements and not recorded as a cost in the year paid. Other than a short number of years when the largest projects (e.g., Conawapa) are nearing completion, this factor is assumed to be relatively minor.

- **Discount Rate:** For discounting purposes, to compare the different Scenarios, a number of discount rates were used covering a wide range of possibilities:

    - ***Primary Discount Rate:*** The primary discount rate used was a real rate of 5.05%. This rate was converted to a nominal rate at the appropriate inflation assumption for each respective Scenario. The selection of this value as the primary rate has two benefits: first, it is within the range of a reasonable baseline discount rate for assessing projects in the current environment. For example, many Crown utility and government policy decision-making discount rates have been set within this range in recent years[3], and second, it is the same as the real rate used by Manitoba Hydro in their own analysis in the NFAT. It is important to note however that Hydro selected the 5.05% as a strict representation of the Corporate Weighted Average Cost of Capital ("WACC"). InterGroup has elected to use this same rate as the benchmark rate based on overall reasonableness, not strictly to reflect the WACC. There are scenarios modelled in the InterGroup financial analysis where the WACC is varied (e.g., high economic assumptions) but the InterGroup analysis does not automatically vary the real discount rate.

[3]For example, Hydro provides a description of its selection of the social discount rate of 6% in Chapter 13. Similarly, NALCOR (Newfoundland Hydro) used 5.88% real for recent Muskrat Falls investigations. BC Hydro also uses 5% or 6% as a discount rate for utility-owned resource planning.

- ***Low Discount Rate Sensitivity:*** In order to test a low discount rate, InterGroup used a real rate of 1.86%. This parallels the rate proposed by Hydro in PUB/MH I-149(a) REVISED. Hydro selected this rate based on the assertion that this "represents the real return on risk free savings of the customer, which reflects the compensation customers receive for saving"[4]. InterGroup does not accept the rationale that this represents a reasonable discount rate for customers[5]. However the value of 1.86% real would qualify as a low discount rate for sensitivity analysis and is comparable to discount rates applied in cases of extremely long horizon impacts.

- ***High Discount Rate Sensitivity:*** A similar discount rate sensitivity or stress test was completed at a 10% real discount rate. This is a high discount rate for the current environment, but is within the range of reasonable values that should be tested in making a decision between competing visions for the power system.

- ***Conversion of Real Discount Rate to Nominal:*** Since the InterGroup analysis was completed based on the financial statement type of data in Appendix 11.4 (which is in nominal dollars), to convert the real discount rate to nominal, inflation was added to the discount rate as appropriate for each economic scenario (1% inflation was added for low economic scenarios, 1.9% inflation was used for reference economic scenarios and 3% inflation was used in high economic scenarios)[6] resulting in primary nominal discount rates of 6.10%, 7.05% and 8.20% for the low, reference and high economic scenarios respectively. Similar adjustments were made to the high and low discount rate sensitivities.

The key data processing step in the analysis considered Hydro's Appendix 9.3 data for all eight plans provided. The NPV of total domestic rates forecast to be paid was calculated for each year for each of the Plans, and in relation to all other Plans (output below typically focuses on comparing each Plan to Plan 1 (All Gas) similar to Hydro's quilt in Appendix 9.3, Figure 2.7.2).

[4] PUB/MH-I-149(a) REVISED, page 2-3.

[5] There is no basis to suggest that 1.86% real represents a reasonable customer perspective on the time preference for returns to their investments through rates (pay higher rates today to get lower rates in future) much less that such a rate could be applied assuming there is no need to further consider risks to customer. Customers clearly face risks with respect to their "investment" via higher Hydro rates, both from the possibility that the benefits in future will not arise, as well as such practical matters as whether the customer may, for example, move away from Manitoba and never see any return on the higher rates they pay in the near-term.

[6] Approximated as per Appendix 11.2: Projected Escalation, Interest and Exchange shown as the 2020 & on MB CPI rate.

The Financial Forecast data was broken into a number of component parts, each comparing a given Plan to any other Plan:

1) The first calculation is the extent to which two plans have a positive or negative impact on export revenues;

2) The second item is the extent of impact between the two plans on the fuel and purchased power expense. These first two items once combined, fundamentally portray the full gross benefit of plans such as Plan 14 (PD) or Plan 4 (K19/Gas/250MW) as compared to a baseline plan of Plan 1 (All Gas);

3) The next item assessed is the changes in the cost of interest (net of debt guarantee fee) for a given Plan versus other options;

4) Then the costs related to depreciation (or amortization of sunk costs, for Plans where this is relevant);

5) The cost of operating, maintenance and administration expenses ("O&M");

6) The amount of charges paid to Government (water rentals and assessments, capital and other taxes and debt guarantee fees);

7) Changes to Reserves as represented by Net Income retained by Hydro;

8) Non-controlling interest, which represents the benefits paid to First Nation Partners to address their ownership interest; and

9) The final component under this approach is the benefit/cost to domestic ratepayers (calculated as the NPV of general consumers revenue at approved rates and additional general consumers revenue).

The above analysis was calculated on a per year basis for all 27 scenarios provided.

The methodology applied looked at a sequence of analyses:

1) **"Waterfall" Graphs:** Comparing each item in the Financial Forecast for a given Plan to any other Plan (typically Plan 1 (All Gas)) under the reference conditions for energy prices (or export revenues), economic conditions and capital costs or "REF-REF-REF" conditions.

    a. **50 Year**: Looks at the waterfall presentation over a 50 year horizon.

b. **Shorter Horizon Waterfall Graphs (25, 30, 35, 40 and 45 year):** The same waterfall presentation (REF-REF-REF conditions), but with the horizon shortened to understand the time periods where benefits arise.

2) **50 Year "Quilt" Tables:** Comparing only the Ratepayer metric from the Financial Forecast for all Plans to Plan 1 (All Gas) over a 50 year horizon under REF-REF-REF conditions. [Quilts can also be produced for shorter horizons, however this appendix focused on the 50 year values.]

3) **Ratepayer Risk over 50 years "Cone" Graphs:** The total NPV of the Expected Value ("EV") amounts paid by ratepayers, as well as the 10th percentile (P10) to 90th percentile (P90) range, under the various plans.

a. One added scenario analysis is provided looking at ratepayer risks under a narrowed range of future scenarios where the energy prices (i.e. export revenues, gas prices) are forced to the LOW value and not allowed to vary to the REF or HIGH levels.

4) **Government Benefits over 50 years - Quilt and Cone Graphs:** Similar presentation as #3 above for Government benefits (including debt guarantee fees, water rentals and capital taxes paid to the Provincial Government, increases in Retained Earnings for the Provincial Government as shareholder, and payments to First Nation Government partners as Non-Controlling Interest[7]).

5) **Ratepayer Discount Rate Sensitivity Cone Graphs:** Under the high and low discount rate scenarios noted above.

6) **Preferred Development Plan Rate Impacts – Mitigation Option:** The analysis in this appendix highlights financial challenges with the adopting of Plan 14 (PDP) for ratepayers. This is despite the plan having by far the highest combined benefits for the province overall. One option to address this disparity is a potential rebalancing of project benefits or project risks to ensure balance.

The primary Plans reviewed in this Appendix are Plan 1 (All Gas) as the baseline, Plan 4 (K19/Gas/250MW) as the smallest scale opportunity-focused plan, and Plan 14 (PDP). Plan 6 (K19/Gas/750MW) is also shown in select places, as it is useful as a comparative plan showing the impacts of pursuing the optionality that comes with the 750 MW US Interconnection over Plan 4 (K19/Gas/250MW).

[7] Benefits to First Nation partners as a result of Conawapa may not be included. MIPUG/MH II-005b – Manitoba Hydro stated that an assumption regarding Conawapa income opportunities was included in the Appendix 11.4 financial statements but did not clarify it was included in the Financial Forecast.

2.0 FINANCIAL ANALYSIS RESULTS – "WATERFALL" GRAPHS

The waterfall graphs in this section show the distribution of financial costs/revenues among different components of the Financial Forecast under the Reference Scenario[8] (i.e. the scenario that Manitoba Hydro considers "most likely" for the three largest impact factors, economic conditions, energy prices and capital costs also known as "REF-REF-REF").

2.1 HOW TO READ

The Waterfall graphs compare the incremental benefits and costs between different development plans. As individual bars increase on the y-axis it is adding benefit to Hydro's financial forecasts, which may ultimately contribute to ratepayer benefits. In contrast as bars on the graph step back downward on the y-axis, it represents deductions from the financial forecast that erodes from the benefits ultimately available to ratepayers.

The financial analysis provided in Appendix 11.4 allows for the splitting of each cost on an annual basis. As can be seen in Section 2.2 below the graphs are split into different cost categories and three different colours as follows:

- The green bars show the incremental gross benefits of the larger Plans, in the form of additional export revenues or avoided fuel and purchased power costs as between the two plans being compared;
- The yellow bars show the incremental added costs of interest, depreciation, O&M, government charges (including debt guarantee fees, water rental fees and taxes), additional reserve requirements and payments to First Nation government partners; and
- The final bar shows the residual difference between the green and yellow bars – the remaining amount that is a benefit to ratepayers This can also show up as a negative value on the y-axis which is a net cost to ratepayers for pursuing the modelled Plan (increased NPV of domestic revenues) (where values are negative to ratepayers, this bar is shown in red). In the case of Figure 1 below, the situation indicates a benefit to ratepayers (decreases to the NPV of domestic rates paid) so the final bar is blue.

The waterfall graphs can be run in five year increments to help show the timing of benefits to ratepayers (if benefits are seen) or the "cross-over" point.

[8] For Plan 1 (All Gas) - Appendix 11.4: Pro Forma Financial statements Volume I pages 2-7 of 648; For Plan 14 (PDP) – Appendix 11.4: Pro Forma Financial Statements Volume II pages 163 – 168 of 648.

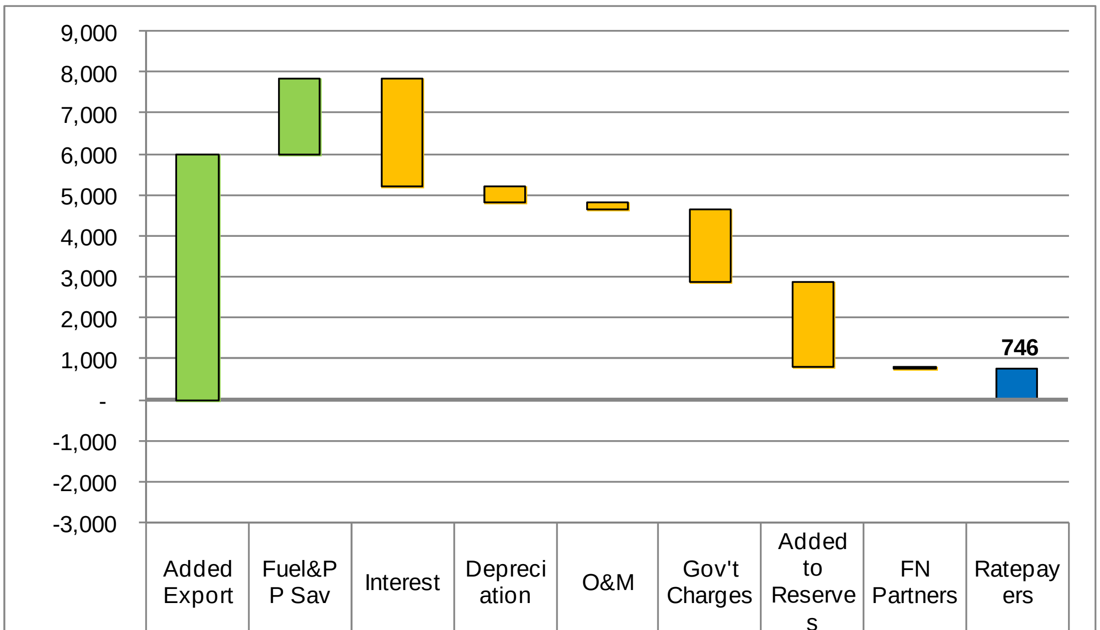
2.2 RESULTS FOR 50 YEARS

The following plan comparisons are reviewed in this section:

1) Plan 14 (PDP) as compared to Plan 1 (All Gas) under the REF-REF-REF scenario (Figure 1 below); and

2) Plan 4 (K19/Gas/250MW) as compared to Plan 1 (All Gas) for the REF-REF-REF scenario (Figure 2 below).

Figure 1: Year 50 – REF-REF-REF Plan 1 vs. Plan 14(NPV $ Millions) at 5.05% Real Discount Rate



	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									746
before	-	5,980	7,858	5,215	4,828	4,640	2,864	802	
after	5,980	7,858	5,215	4,828	4,640	2,864	802	746	

Figure 1 shows that pursuing Plan 14 (PDP) provides material benefits over 50 years, as compared to Plan 1 (All Gas) in the areas of added export revenues ($5.980 billion in added NPV) and in savings in Fuel and Purchased Power (an additional $1.878 billion benefit, for a total benefit of $7.858 billion NPV).

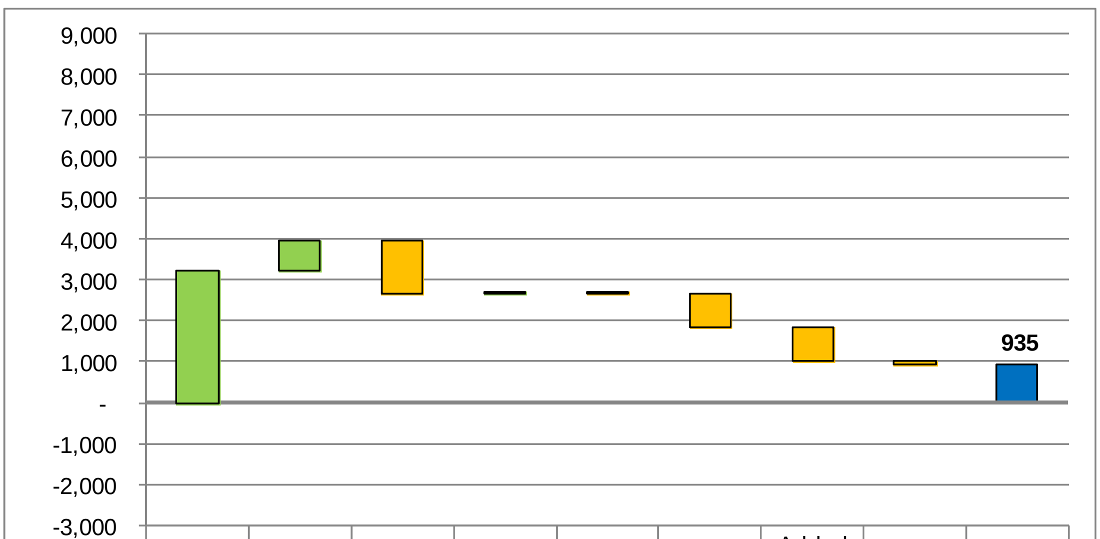
Of this $7.848 billion gross benefit from added exports and avoided fuel and purchased power, $2.643 billion in NPV will be required to pay interest costs to lenders for Plan 14 (PDP) compared to Plan 1 (All Gas), $0.387 billion NPV will be recorded as depreciation expense, and there will be $0.188 billion in added NPV of O&M.

Portraying the full benefit to Manitoba of Plan 14 (PDP) over Plan 1 (All Gas) over 50 years under REF-REF-REF conditions, this represents **$4.640 billion** NPV. The allocation of this $4.640 billion in benefits is as follows:

- **$1.776 billion** NPV is paid to the Provincial Government in various fees, charges and capital taxes. This does not include other benefits accruing to the Provincial Government from such matters as worker income taxes or indirect effects of economic activity.
- **$2.042 billion** NPV is retained as Net Income added to Hydro's reserves. This serves to increase the value of the Hydro entity for its shareholder, the Provincial Government as well as to help stabilize rates.
- **$0.052 billion** NPV is paid out to First Nation Governments participating in the projects.

The remaining **$0.746 billion** NPV is arises as ratepayer benefits (i.e., a lower NPV of total domestic rates paid).

Figure 2: Year 50 - REF-REF-REF Plan 1 vs. Plan 4 (NPV $ Millions) at 5.05% Real Discount Rate



	Added Export	Fuel&P P Sav	Interest	Depreci ation	O&M	Gov't Charges	Added to Reserve s	FN Partners	Ratepay ers
ends -									935
before	-	3,216	3,940	2,669	2,711	2,661	1,839	1,016	
after	3,216	3,940	2,669	2,711	2,661	1,839	1,016	935	

Figure 2 above is based on the same basic concept as Figure 1, except that the plans compared are Plan 4 (K19/Gas/250MW) and Plan 1 (All Gas) under REF-REF-REF conditions. Under Plan 4 the export revenue benefits and the fuel and purchased power savings are not as large as under Plan 14 (total

$3.940 billion as compared to $7.858 billion in Figure 1). However, the cost components are also much smaller (depreciation in particular is actually lower NPV cost under Plan 4 than Plan 1 as shown in the above Figure). Government charges are also much smaller, with direct Provincial Government charges totalling $0.822 billion as compared to $1.776 billion under Plan 14. However even though gross benefits are approximately half that of Plan 14 (PDP), the end result of these changes is a net improvement for ratepayers. Under Plan 14 (PDP) ratepayers face an NPV of costs that are $0.746 million better (i.e. lower) than under Plan 1 (All Gas) while under Plan 4 (K19/Gas/250MW) then NPV benefit to ratepayers over Plan 1 (All Gas) is $0.935 billion. In short, over 50 years in REF-REF-REF conditions Plan 4 (K19/Gas/250MW) is more financially beneficial to ratepayers than Plan 14 (PDP).

2.3 RESULTS OVER SHORTER HORIZONS (25, 30, 35, 40, 45 YEARS)

The following plan comparisons are reviewed in this section:

1. Plan 14 (PDP) as compared to Plan 1 (All Gas) for the REF-REF-REF scenario (Figure 3 though Figure 7 below); and

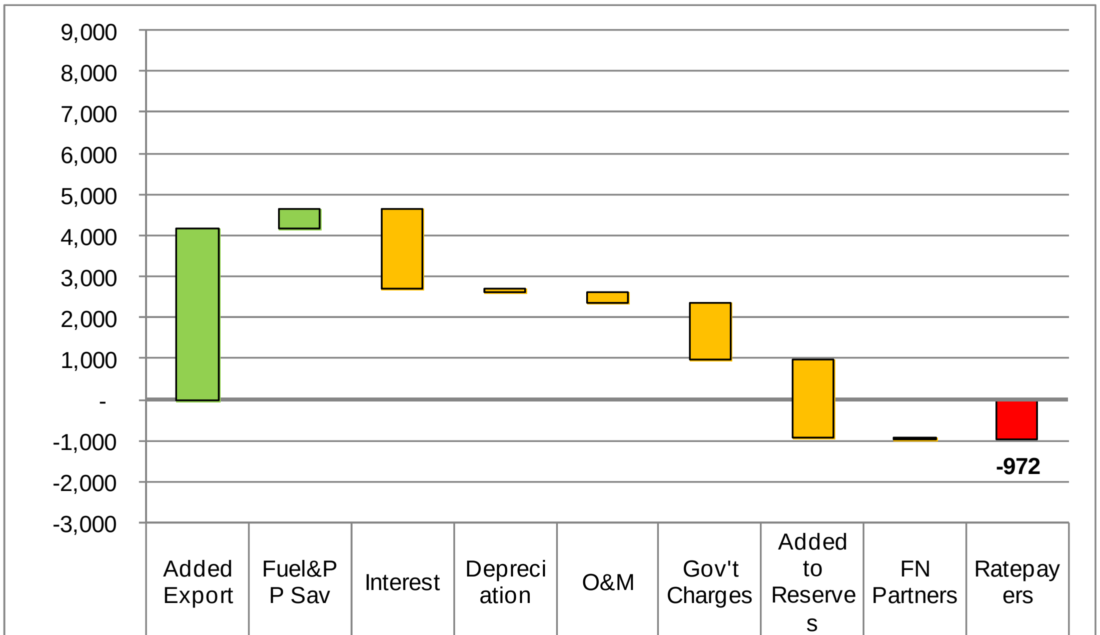
2. Plan 4 (K19/Gas/250MW) as compared to Plan 1 (All Gas) for the REF-REF-REF scenario (Figure 8 through Figure 12below).

The waterfall graphs in the previous section (calculated over 50 years) clarify that both Plan 14 (PDP) and Plan 4 (K19/Gas/250MW) are beneficial to ratepayers on an NPV basis over the long-term under REF-REF-REF conditions. This section reviews the time horizon required to achieve these positive outcomes.

2.3.1 Shorter Horizons for Plan 14 (PDP)

Focusing first on Plan 14 (PDP), Figure 3 below sets out the same waterfall presentation set out above, but with the horizon limited to the first 25 years of the project horizon (to 2037).

Figure 3: Year 25 – REF-REF-REF Plan 1 vs. Plan 14 (NPV $ Millions) at 5.05% Real Discount Rate



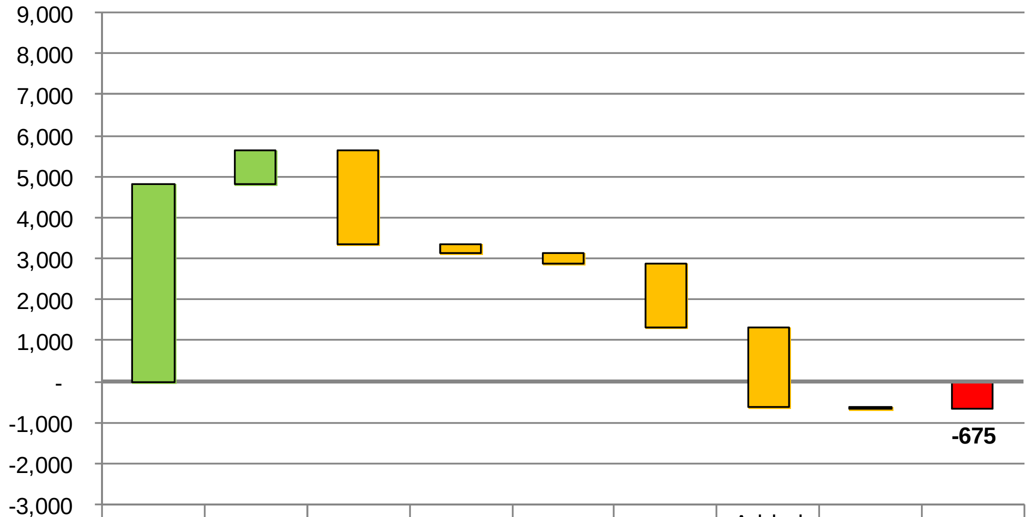
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									-972
before	-	4,180	4,650	2,688	2,627	2,353	955	-947	
after	4,180	4,650	2,688	2,627	2,353	955	-947	-972	

Figure 3 above shows that under the first 25 years of a Plan 14 (PDP) future, there are material gross benefits from added export revenues and savings in fuel and purchased power as compared to Plan 1 (All Gas). These gross benefits total $4.650 billion. In order to achieve these benefits, costs for interest, depreciation and added O&M must be incurred, resulting in $2.353 billion in remaining net benefits to Manitoba overall from pursuing Plan 14 (PDP).

The unfortunate outcome for ratepayers relates to the distribution of these net benefits. The payments to the Provincial Government under this scenario over the 25 years total $1.398 billion, while $1.902 billion in NPV of Net Income is retained within the shareholder's equity of Hydro. After a small First Nation Partner adjustment, the net impact on ratepayers over this period results in $0.972 billion NPV of higher domestic rates paid (as represented by the negative number in Figure 3 above). In short, over this horizon, ratepayers are materially worse off under Plan 14 (PDP) than under Plan 1 (All Gas).

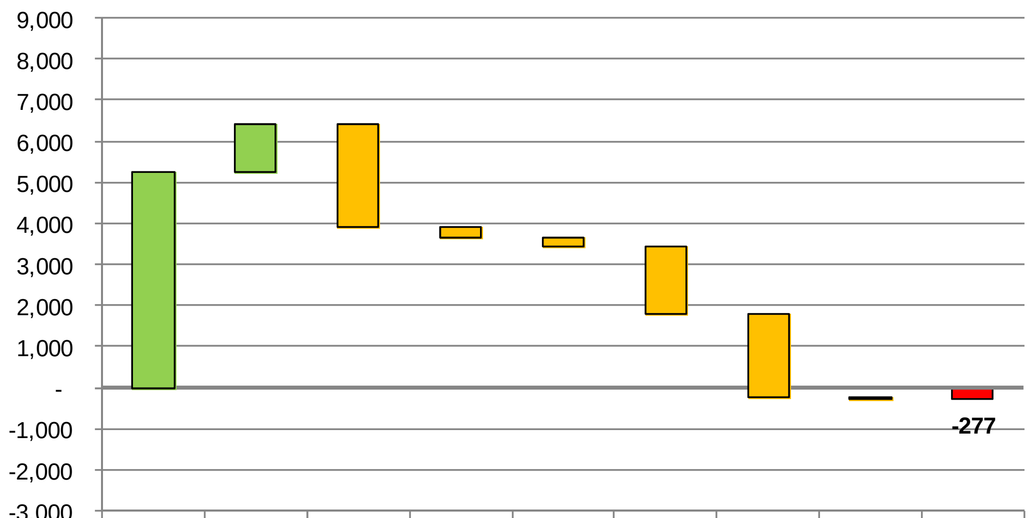
The following series of charts continues the presentation shown in Figure 3 above, in five year intervals to show the stepped changes to revenues and costs as time progresses. It demonstrates increasing gross benefits over time, and the distribution of those benefits, such that ratepayers are not brought whole on an NPV basis until approximately year 40 (2052) of the scenario.

Figure 4: Year 30 - REF-REF-REF Plan 1 vs. Plan 14 ($ Millions) at 5.05% Real Discount Rate



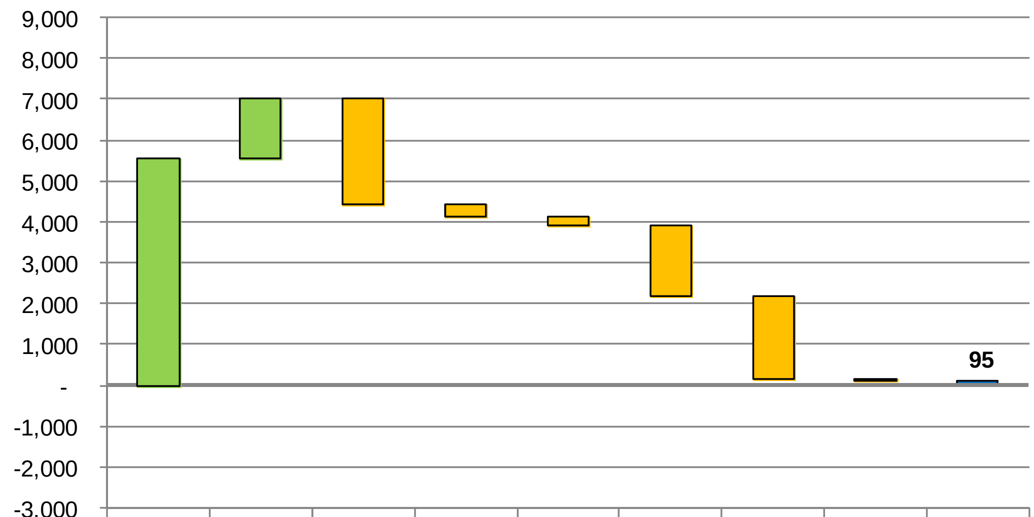
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									-675
before	-	4,811	5,620	3,332	3,142	2,882	1,337	-640	
after	4,811	5,620	3,332	3,142	2,882	1,337	-640	-675	

Figure 5: Year 35 – REF-REF-REF Plan 1 vs. Plan 14 ($ Millions) at 5.05% Real Discount Rate



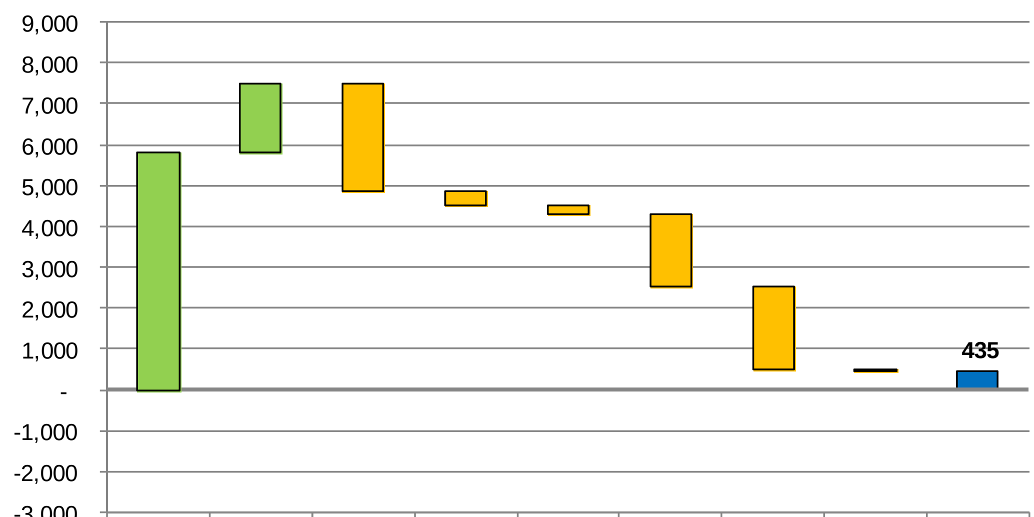
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									-277
before	-	5,237	6,396	3,928	3,660	3,422	1,783	-235	
after	5,237	6,396	3,928	3,660	3,422	1,783	-235	-277	

Figure 6: Year 40 – REF-REF-REF Plan 1 vs. Plan 14($ Millions)
at 5.05% Real Discount Rate



	Added Export	Fuel&P P Sav	Interest	Depreci ation	O&M	Gov't Charges	Added to Reserve s	FN Partners	Ratepay ers
ends -									95
before	-	5,548	7,010	4,436	4,111	3,893	2,188	143	
after	5,548	7,010	4,436	4,111	3,893	2,188	143	95	

Figure 7: Year 45 – REF-REF-REF Plan 1 vs. Plan 14 ($ Millions)
at 5.05% Real Discount Rate



	Added Export	Fuel&P P Sav	Interest	Depreci ation	O&M	Gov't Charges	Added to Reserve s	FN Partners	Ratepay ers
ends -									435
before	-	5,791	7,487	4,860	4,499	4,297	2,547	488	
after	5,791	7,487	4,860	4,499	4,297	2,547	488	435	

The above charts illustrate one particular characteristic of the Plan 14 (PDP), as compared to Plan 1 (All Gas). Under the REF-REF-REF forecast, Plan 14 has a notable positive NPV over 50 years, but this hinges on an extremely positive financial performance in years 40-50. It takes the entire period to year 40 for ratepayers to recover benefits equal to the costs they incurred from higher rates in the early decades of the PDP. While $0.758 billion in NPV benefits is material, the “home run” nature of financial performance in years 40 through 50 could be a basis for potential concern over even small compounding uncertainties in the long-term conditions assumed.

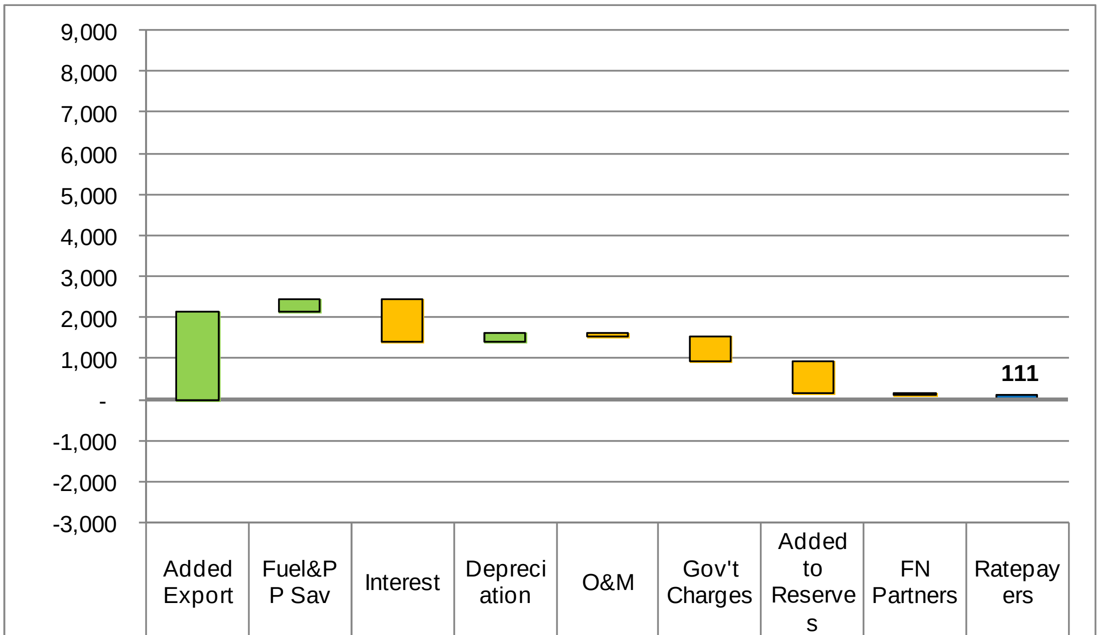
Of note, the above graphs indicate that on an NPV basis, there is a significant delay in the cross-over point related to Plan 14 (PDP) of approximately 40 years (the year 2052). This finding is generally inconsistent with Hydro’s claims that plans that include both Keeyask and Conawapa “cross-over” compared to all other plans and begin to provide ratepayers benefits in a relatively short timeframe (10 to 15 years) after the in-service of Conawapa[9].

2.3.2 Shorter Horizons for Plan 4 (K19/Gas/250MW) REF-REF-REF

The series of waterfall graphs below depict the breakdown of incremental costs and revenues of Plan 4 (K19/Gas/250MW) to Plan 1 (All Gas) over the shorter horizon (25-45 years). Of particular note, under Plan 4 (K19/Gas/250MW) the ratepayer benefits begin to arise as soon as 25 years (the first figure below) and are not dependent to the same degree on the excellent financial performance between years 40 and 50 as the per the outcome for Plan 14 (PDP).

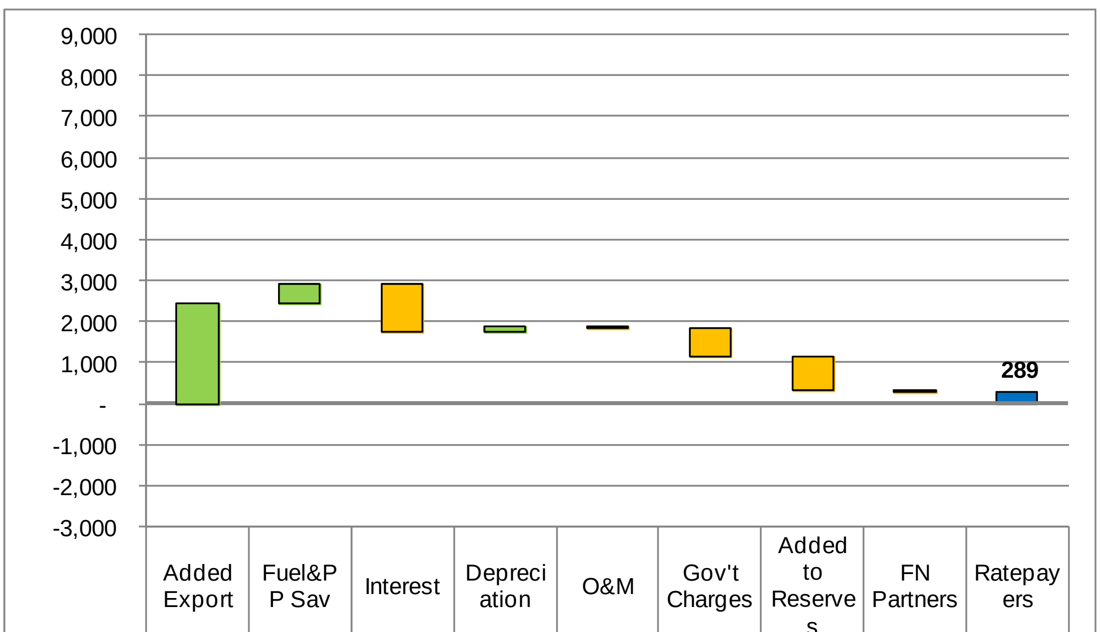
[9] NFAT Business Case, Chapter 11: Financial Evaluation of Development Plans, page 1 and 2 (August, 2013).

Figure 8: Year 25 - REF-REF-REF Plan 1 vs. Plan 4 ($ Millions) at 5.05% Real Discount Rate



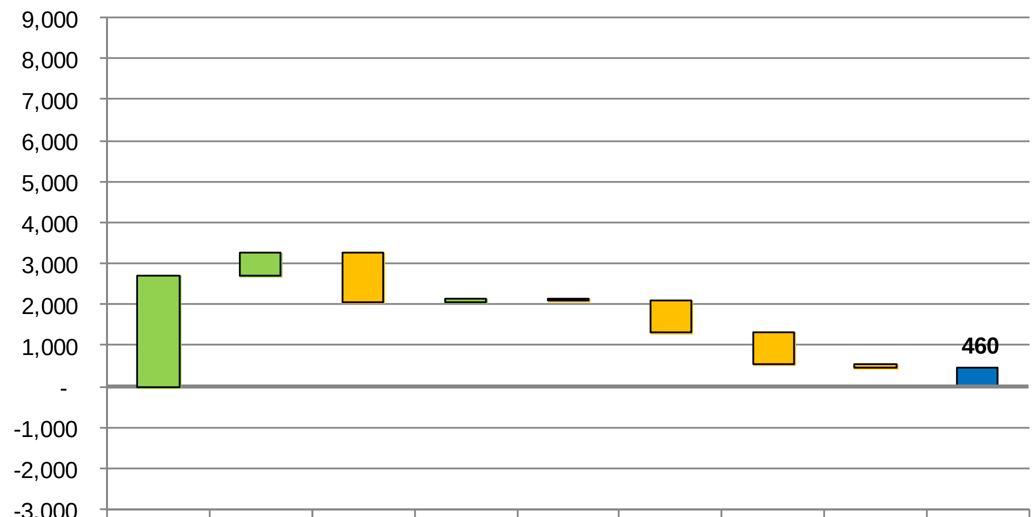
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									111
before	-	2,127	2,455	1,423	1,617	1,555	913	154	
after	2,127	2,455	1,423	1,617	1,555	913	154	111	

Figure 9: Year 30 - REF-REF-REF Plan 1 vs. Plan 4 ($ Millions) at 5.05% Real Discount Rate



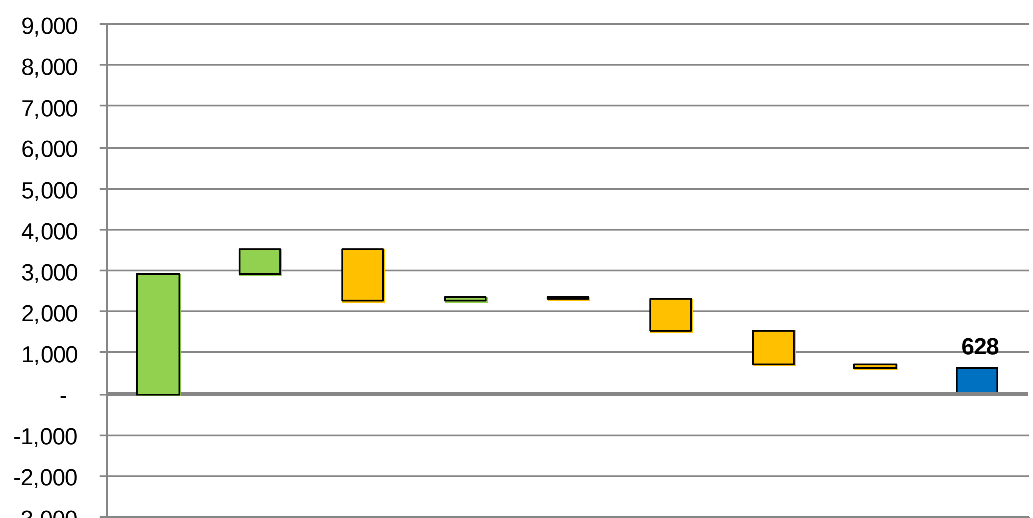
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									289
before	-	2,448	2,895	1,751	1,895	1,839	1,131	343	
after	2,448	2,895	1,751	1,895	1,839	1,131	343	289	

Figure 10: Year 35 - REF-REF-REF Plan 1 vs. Plan 4 ($ Millions) at 5.05% Real Discount Rate



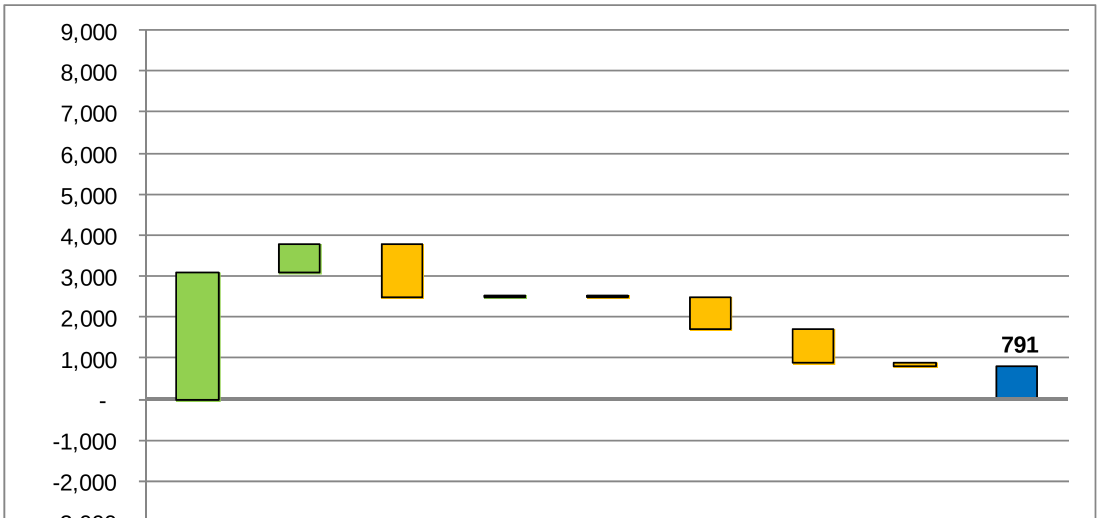
	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									460
before	-	2,713	3,251	2,034	2,138	2,084	1,330	523	
after	2,713	3,251	2,034	2,138	2,084	1,330	523	460	

Figure 11: Year 40 - REF-REF-REF Plan 1 vs. Plan 4 ($ Millions) at 5.05% Real Discount Rate



	Added Export	Fuel&PP Sav	Interest	Depreciation	O&M	Gov't Charges	Added to Reserves	FN Partners	Ratepayers
ends -									628
before	-	2,923	3,540	2,282	2,357	2,304	1,517	699	
after	2,923	3,540	2,282	2,357	2,304	1,517	699	628	

Figure 12: Year 45 - REF-REF-REF Plan 1 vs. Plan 4 ($ Millions) at 5.05% Real Discount Rate



	Added Export	Fuel&P P Sav	Interest	Depreci ation	O&M	Gov't Charges	Added to Reserve s	FN Partners	Ratepay ers
ends -									791
before	-	3,088	3,765	2,494	2,549	2,498	1,690	867	
after	3,088	3,765	2,494	2,549	2,498	1,690	867	791	

In contrast to Plan 14 (PDP), Plan 4 (K19/Gas/250MW) provides ratepayer benefits compared to Plan 1 (All Gas) early under the REF-REF-REF scenario (before year 25) and continues to be more beneficial to ratepayers throughout the 50 year financial forecast.

3.0 FINANCIAL ANALYSIS RESULTS– 50 YEAR "QUILT" PRESENTATION

The above waterfall figures present considerable detail on the various components that make up the Financial projections under each Plan modelled, to derive the resulting impacts on ratepayers. The above presentation however is limited in that it only provides a comparison between two chosen Plans (e.g., Plan 14 (PDP) and Plan 1 (All Gas)) and it only provides the outcomes under REF-REF-REF conditions.

In order to provide a comparison across all eight plans provided in the NFAT Appendix 9.3 and under the various Scenarios, the quilt presentation developed by Hydro was adopted in the following tables.

Table 1 shows the present value of ratepayer costs (or Manitoba Hydro domestic revenues) for each plan compared with Plan 1 (All Gas) of the same scenario (similar to Manitoba Hydro's Table 2 from the NFAT Business Case Executive Summary[10]); including the probabilities of occurrence calculated by Hydro for each scenario along the right hand side of the Table.

Table 1: Net Present Value Benefits of Alternative Development Plans to Ratepayers as Compared to Plan 1 (All Gas) Over 50 years – 5.05% Real Discount Rate ($ Millions)

Development Plan			Pathway 1	Pathway 2		Pathway 3		Pathway 4		Pathway 5	
Energy Prices	Econ.	Capital Costs	1	7	2	4	13	6	12	14	Probability
Low	Low	High	0	(760)	(411)	(205)	(1,428)	(428)	(1,423)	(1,155)	1.35%
Low	Low	Ref	0	(711)	(219)	26	(1,067)	(182)	(1,046)	(737)	2.25%
Low	Low	Low	0	(645)	(112)	208	(764)	(16)	(733)	(368)	0.90%
Low	Ref	High	0	(1,267)	(652)	(515)	(2,409)	(749)	(2,238)	(2,125)	4.50%
Low	Ref	Ref	0	(1,170)	(436)	(225)	(1,931)	(457)	(1,751)	(1,581)	7.50%
Low	Ref	Low	0	(1,083)	(437)	(69)	(1,605)	(308)	(1,413)	(1,194)	3.00%
Low	High	High	0	(1,459)	(399)	(437)	(2,664)	(700)	(2,391)	(2,323)	3.15%
Low	High	Ref	0	(1,326)	(230)	(173)	(2,155)	(415)	(1,892)	(1,720)	5.25%
Low	High	Low	0	(1,222)	(196)	(6)	(1,776)	(273)	(1,484)	(1,254)	2.10%
Ref	Low	High	0	483	634	911	796	705	638	1,056	2.48%
Ref	Low	Ref	0	535	814	1,152	1,185	958	1,030	1,489	4.12%
Ref	Low	Low	0	589	930	1,320	1,487	1,115	1,342	1,841	1.65%
Ref	Ref	High	0	11	203	593	(121)	379	(111)	146	8.25%
Ref	Ref	Ref	0	128	463	935	397	717	427	746	13.75%
Ref	Ref	Low	0	210	595	1,101	753	884	780	1,139	5.50%
Ref	High	High	0	(21)	433	685	(188)	442	(106)	134	5.78%
Ref	High	Ref	0	104	689	1,013	366	789	472	782	9.63%
Ref	High	Low	0	227	770	1,232	814	1,004	907	1,270	3.85%
High	Low	High	0	1,841	1,722	2,083	3,212	1,884	2,820	3,340	0.68%
High	Low	Ref	0	1,901	1,907	2,336	3,610	2,146	3,230	3,800	1.13%
High	Low	Low	0	1,950	2,017	2,489	3,888	2,295	3,520	4,124	0.45%
High	Ref	High	0	1,456	1,422	1,856	2,434	1,645	2,225	2,566	2.25%
High	Ref	Ref	0	1,551	1,637	2,142	2,913	1,932	2,693	3,112	3.75%
High	Ref	Low	0	1,645	1,776	2,323	3,281	2,124	3,074	3,532	1.50%
High	High	High	0	1,577	1,652	2,091	2,646	1,863	2,486	2,837	1.58%
High	High	Ref	0	1,716	1,922	2,386	3,185	2,171	3,044	3,422	2.63%
High	High	Low	0	1,825	2,069	2,588	3,590	2,369	3,442	3,914	1.05%

[10] Page 23 of Manitoba Hydro's NFAT Business Case: Executive Summary (August 2013).

Table 2 shows the present value of ratepayer costs (or Manitoba Hydro domestic revenues) for each plan compared with Plan 1 (All gas) REF-REF-REF scenario, similar to Manitoba Hydro's Table 10.5 from Chapter 10 of the NFAT Business Case[11].

Table 2: Net Present Value Benefits of Alternative Development Plans to Ratepayers as Compared to Plan 1 (All Gas) REF-REF-REF Over 50 Years – 5.05% Real Discount Rate ($ Millions)

Development Plan			Pathway 1	Pathway 2		Pathway 3		Pathway 4		Pathway 5	
Energy Prices	Econ.	Capital Costs	1	7	2	4	13	6	12	14	Probability
Low	Low	High	498	(262)	87	293	(930)	70	(925)	(656)	1.35%
Low	Low	Ref	977	266	758	1,003	(90)	795	(69)	240	2.25%
Low	Low	Low	1,369	724	1,257	1,577	606	1,353	637	1,001	0.90%
Low	Ref	High	(463)	(1,730)	(1,115)	(978)	(2,873)	(1,212)	(2,702)	(2,588)	4.50%
Low	Ref	Ref	89	(1,081)	(347)	(136)	(1,842)	(368)	(1,662)	(1,492)	7.50%
Low	Ref	Low	525	(558)	89	456	(1,080)	217	(888)	(669)	3.00%
Low	High	High	(717)	(2,176)	(1,117)	(1,154)	(3,382)	(1,417)	(3,108)	(3,040)	3.15%
Low	High	Ref	(120)	(1,446)	(351)	(294)	(2,275)	(535)	(2,012)	(1,841)	5.25%
Low	High	Low	346	(876)	150	340	(1,430)	73	(1,138)	(908)	2.10%
Ref	Low	High	340	822	974	1,250	1,136	1,044	978	1,396	2.48%
Ref	Low	Ref	822	1,357	1,637	1,975	2,007	1,780	1,853	2,311	4.12%
Ref	Low	Low	1,215	1,804	2,144	2,535	2,702	2,329	2,557	3,056	1.65%
Ref	Ref	High	(539)	(528)	(336)	55	(660)	(160)	(650)	(392)	8.25%
Ref	Ref	Ref	0	128	463	935	397	717	427	746	13.75%
Ref	Ref	Low	435	645	1,030	1,536	1,188	1,319	1,215	1,574	5.50%
Ref	High	High	(797)	(819)	(364)	(112)	(985)	(355)	(903)	(663)	5.78%
Ref	High	Ref	(197)	(93)	491	816	169	592	274	585	9.63%
Ref	High	Low	255	482	1,025	1,488	1,069	1,259	1,162	1,526	3.85%
High	Low	High	(9)	1,832	1,713	2,074	3,203	1,875	2,811	3,331	0.68%
High	Low	Ref	470	2,371	2,377	2,806	4,080	2,616	3,700	4,270	1.13%
High	Low	Low	866	2,816	2,883	3,355	4,754	3,161	4,387	4,991	0.45%
High	Ref	High	(890)	566	533	967	1,544	756	1,335	1,676	2.25%
High	Ref	Ref	(338)	1,213	1,299	1,804	2,574	1,593	2,355	2,774	3.75%
High	Ref	Low	92	1,737	1,868	2,415	3,373	2,216	3,166	3,624	1.50%
High	High	High	(1,177)	400	475	913	1,468	685	1,309	1,660	1.58%
High	High	Ref	(589)	1,127	1,333	1,797	2,596	1,582	2,455	2,832	2.63%
High	High	Low	(124)	1,701	1,946	2,465	3,467	2,245	3,319	3,790	1.05%

The above quilts, particularly Table 1, emphasize that from a ratepayer's perspective, energy prices are by far the largest impact factor. In particular, the tables note that for Plan 4 (K19/Gas/250MW), the variation between LOW and HIGH energy prices (as compared to Plan 1 (All Gas)) is a NPV effect on ratepayers of upwards of plus or minus $1 billion or more (Plan 14 (PDP) is in the range of +/-$2.0-$2.5 billion). This can be seen by comparing the values in the rows at the bottom third of Table 1 (high export prices), to the middle third (Reference export prices) to the top third (Low export prices).

In contrast, the variation related to LOW or HIGH capital costs is on the order of plus or minus $0.4 to $0.5 billion (Plan 14 (PDP) is comparable)[12]. The variation in economic conditions (including interest costs and inflation but maintaining a 5.05% real discount rate across scenarios) is generally smaller and at

[11] Manitoba Hydro NFAT Business Case, Chapter 10: Economic Uncertainty Analysis – Probabilistic Analysis and Sensitivities, page 17 (August 2013).

[12] Capital cost variability can be seen by comparing sets of rows within a group of 3 consecutive rows with the same Energy Price and Economic assumptions.

times reflects competing assumptions under certain conditions[13] for both Plan 4 (K19/Gas/250MW) and Plan 14 (PDP).

4.0 RATEPAYER RISKS AND "CONE" GRAPHS

Based on the data shown in the quilts above, and generation of similar quilts for each time horizon leading up to 50 years, it is possible to calculate the Expected Value, and the range (P10/P90) values for the likely future domestic rate outcomes (the total rates paid by Manitobans), as follows:

- For each development plan individually, the results of the financial analysis calculations for each scenario are ordered from lowest benefit/(highest cost) to highest benefit/(lowest cost) in five year PV increments (from year 5 to year 50). A 5 year increment permits the ability to graph costs and benefits for both short- and long- term comparison purposes. Table 3 below shows the Plan 1 (All Gas) example for the 50 year values. Note that this was completed on an absolute basis showing the full NPV of amounts paid by ratepayers.

- The probabilities of occurrence for each Scenario were held to the same assumptions developed by Manitoba Hydro in Appendix 9.3. These probabilities were used for calculation of the cumulative probabilities, and EVs[14].

[13] This arises because certain of the assumptions in the economic Scenarios are beneficial (e.g., LOW econ has lower real interest rates) while others are adverse (LOW econ has lower inflation rates assumed. This means that variables such as water rentals, which stay the same on a nominal basis, do not erode in NPV as quickly).

[14] Appendix 9.3: Economic Evaluation Documentation; Section 2: Probabilistic Analysis with Scenarios, page 60.

Table 3: Transforming Scenario Probabilities into Cumulative Probabilities and Percentile Distributions ($ Millions) – 50 year Financial Analysis – 5.05% Real Discount Rate

Probabilities	Plan 1 (All Gas) NPV of Rates	Cumulative Probabilities	Percentile Distribution
0.90%	39,149	0.90%	
1.65%	39,304	1.72%	
2.25%	39,542	3.67%	39,920
0.45%	39,653	5.02%	
4.12%	39,696	7.31%	
3.00%	39,993	10.87%	
1.35%	40,020	13.05%	
1.13%	40,048	14.29%	
5.50%	40,084	17.60%	40,214
2.10%	40,173	21.40%	
2.48%	40,179	23.69%	
3.85%	40,263	26.85%	
1.50%	40,427	29.52%	
7.50%	40,430	34.02%	40,525
13.75%	40,519	44.65%	
0.68%	40,527	51.86%	
5.25%	40,639	54.82%	
1.05%	40,642	57.97%	
9.63%	40,716	63.31%	
3.75%	40,857	70.00%	40,992
4.50%	40,982	74.12%	
8.25%	41,057	80.50%	
2.63%	41,108	85.94%	41,257
3.15%	41,236	88.82%	
5.78%	41,316	93.29%	
2.25%	41,408	97.30%	
1.58%	41,696	99.21%	
Exp. Value	**40,569**	100.00%	

- Once ordered, cumulative probabilities were calculated, using Manitoba Hydro's method of the Scenario outcome, which uses the midpoint of the range as the relevant underlying representative value[15]. Table 3 above shows the cumulative probabilities for the Plan 1 (All Gas).

- Based on the cumulative probabilities, the 10th, 25th, 50th, 75th and 90th percentiles were interpolated.

- Expected Values (EVs) for each Plan were calculated on the basis of the weighted values as reported (not the midpoints), as the sum of each scenario NPV multiplied by the probability of occurrence. For the Plan 1 (All Gas), the EV of ratepayer revenues is $40,569 million. Table 4

[15] NFAT Appendix 9.3, page 65.

below shows the absolute expected value and percentile values for the development plans assessed in the financial analysis.

Table 4: Probabilistic Analysis for Ratepayer Revenues ($ Millions) – 50 year Financial Analysis

	Pathway 1	Pathway 2		Pathway 3		Pathway 4		Pathway 5
NPV of Ratepayer Revenues ($Millions)	**Plan 1: All Gas**	**Plan 7: SCGT/C26**	**Plan 2: K22/Gas**	**Plan 4: K19/Gas24/250MW**	**Plan 13: K19/C25/250MW**	**Plan 6: K19/Gas31/750MW**	**Plan 12: K19/C31/750MW**	**Plan 14: PDP**
Expected Value	40,569	40,580	40,125	39,788	40,464	40,012	40,428	40,130
10th Percentile - "Risk"	39,920	39,216	39,016	38,608	37,938	38,809	38,134	37,727
25th Percentile	40,214	39,913	39,493	39,028	39,350	39,256	39,320	38,960
50th Percentile	40,525	40,530	40,052	39,628	40,309	39,855	40,217	39,905
75th Percentile	40,992	41,343	40,862	40,590	41,577	40,826	41,432	41,186
90th Percentile - "Reward"	41,257	41,981	40,961	40,851	42,827	41,092	42,569	42,401
Expected Value Difference from All Gas	-	12	- 444	- 780	- 105	- 557	- 141	- 439

- From this data, two sets of graphs were developed:

    1. **NPV Total Amount Paid in Rates** graphs use the 10th and 90th percentile amounts as the shaded range of possible outcomes and the expected value of the domestic revenues for each plan graphed by millions of dollars in NPV on the y-axis and by year in the financial forecast as the x-axis.

    2. **NPV Amount Paid in Rates as compared to Plan 1 (All Gas) Expected Value** graphs use the same values as the Total Amount graphs. However for these graphs, each plan's expected value and the percentile distribution range is compared to the expected value of the Plan 1 (All Gas) to focus on the incremental effect of each plan. The amounts are compared for the same time periods (e.g., for 20 years, the NPV of only the first 20 years of the financial analysis is used to compare the P10/P90 percentile range, the EV and the Plan 1 (All Gas) EV; similar comparisons are made at 25 years, 30 years, etc.).

- Each graph uses a 5.05% real discount rate for all economic scenarios (however note that the inflation varies for each scenario to determine the nominal discount rate).

- The described graphs were done over the 50 year financial forecast period showing domestic revenues between Plan 1 (All Gas) and Plan 4 (K19/Gas/250MW) and between Plan 4 (K19/Gas/250MW) and Plan 14 (PDP). Where relevant, Plan 6 (K19/Gas/750MW) was compared to Plan 4 (K19/Gas/250MW) to show the difference in ratepayer benefits between a 250 MW Interconnection and a 750 MW Interconnection.

4.1 RATEPAYER IMPACTS UNDER THE FULL RANGE OF SCENARIOS

Figure 13 through Figure 15 show the comparison of the total NPV of amounts paid by ratepayers under the full P10-P90 range (shaded cone) as well as the EV (dark lines). Where each plan is included in a figure, Plan 1 (All Gas) is set out in **blue**, while Plan 4 (K19/Gas/250MW) is **orange**, Plan 6 (K19/Gas/750MW is **grey** and Plan 14 (PDP) is **green**. Higher values in these Figures indicate higher levels of NPV rates (worse for ratepayers).

As can be seen by the Figure 13 through Figure 15 as well as Table 4 above, a total of approximately $40 billion NPV is projected to be paid by ratepayers in the next fifty years based on Manitoba Hydro's financial analysis regardless of the plan selected or the future scenario that occurs. The key item of note in these Figures is that the selection of a development plan has a notable impact on the level of rates expected to be paid, but the differences are not overwhelming. For the most part, rates under all plans are reasonably comparable. The range of the cones, however, which represents the risks of a particular plan are notably higher and wider for Plan 14 (PDP).

Figure 13: NPV Total Amount Paid in Rates at 5.05% Real Discount Rate Plan 1 (All Gas) vs. 4 (K19/Gas/250MW) ($ Millions)

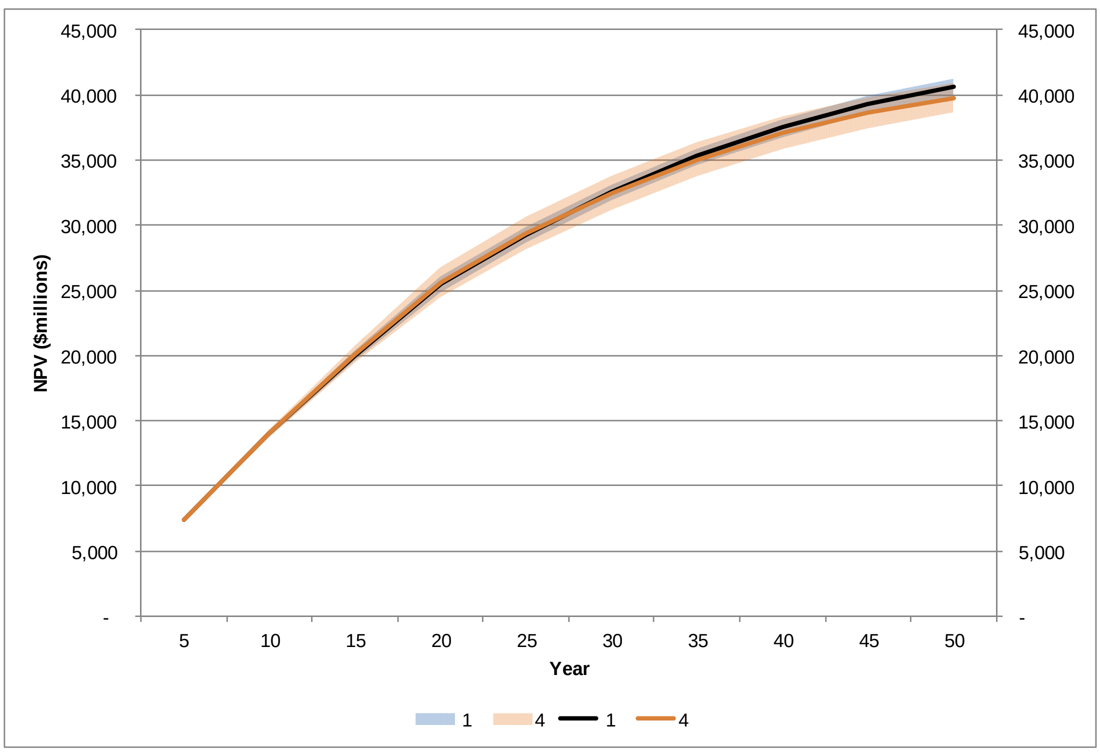


Figure 14: NPV Total Amount Paid in Rates at 5.05% Real Discount Rate Plan 4 (K19/Gas/250MW) vs. 14 (PDP) ($ Millions)

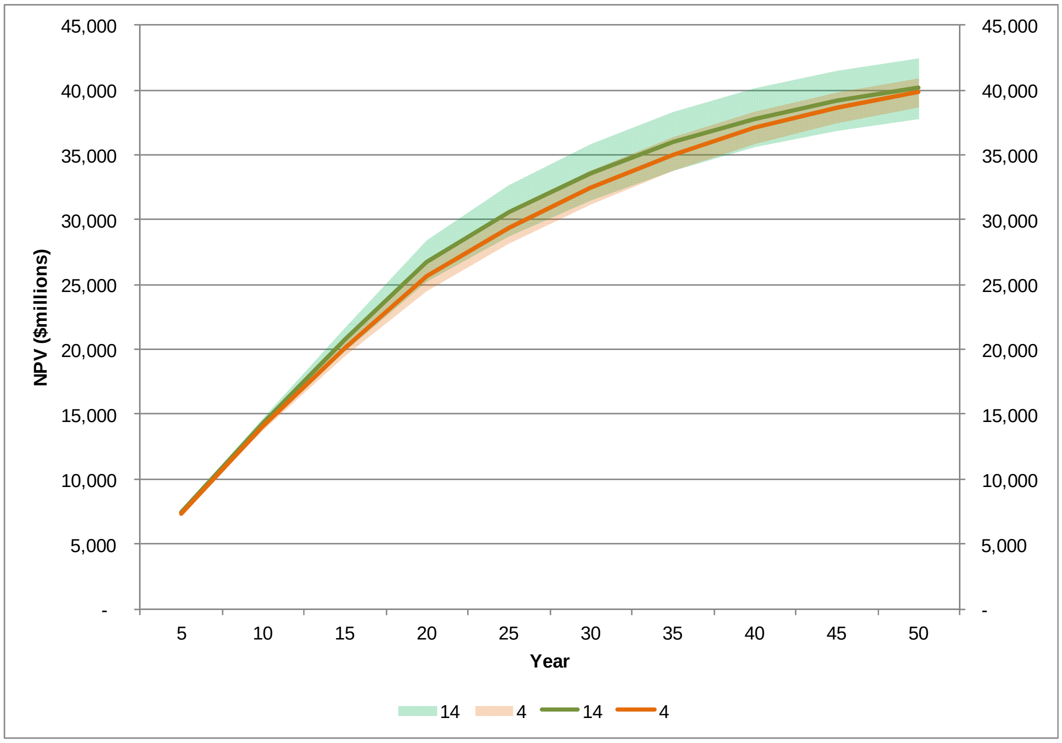
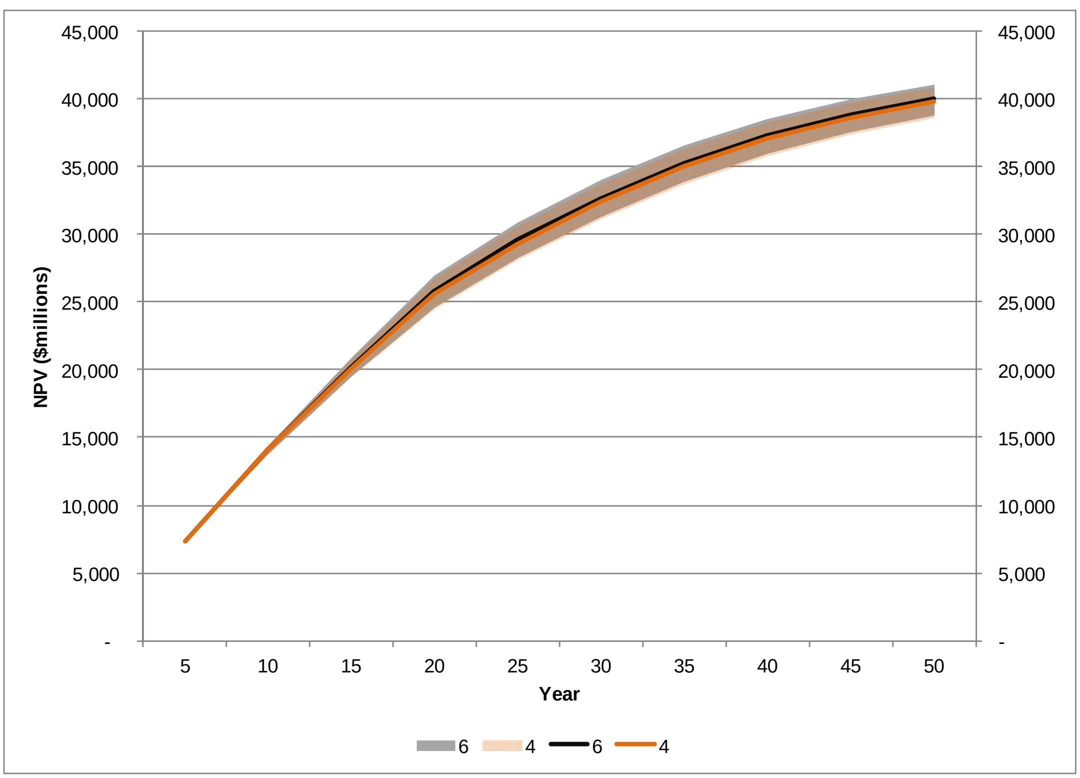


Figure 15: NPV Total Amount Paid in Rates at 5.05% Real Discount Rate Plan 4 (K19/Gas/250MW) vs. 6 (K19/Gas/750MW) ($ Millions)



As the above figures can blur the distinctions between plans, with the overwhelming value of rates that are common to all plans due to existing system forecast expenses, Figure 16 to Figure 18 below compare only the differences - the range of costs to ratepayers (or avoided costs/benefits, represented as negative costs) compared to the expected value of the Plan 1 (All Gas) values.

Figure 16: Plan 1 (All Gas) vs. Plan 4 (K19/Gas/250MW) at 5.05% Real Discount Rate - NPV of Incremental Domestic Costs as Compared to Plan 1 (All Gas) Expected Value ($ Millions)

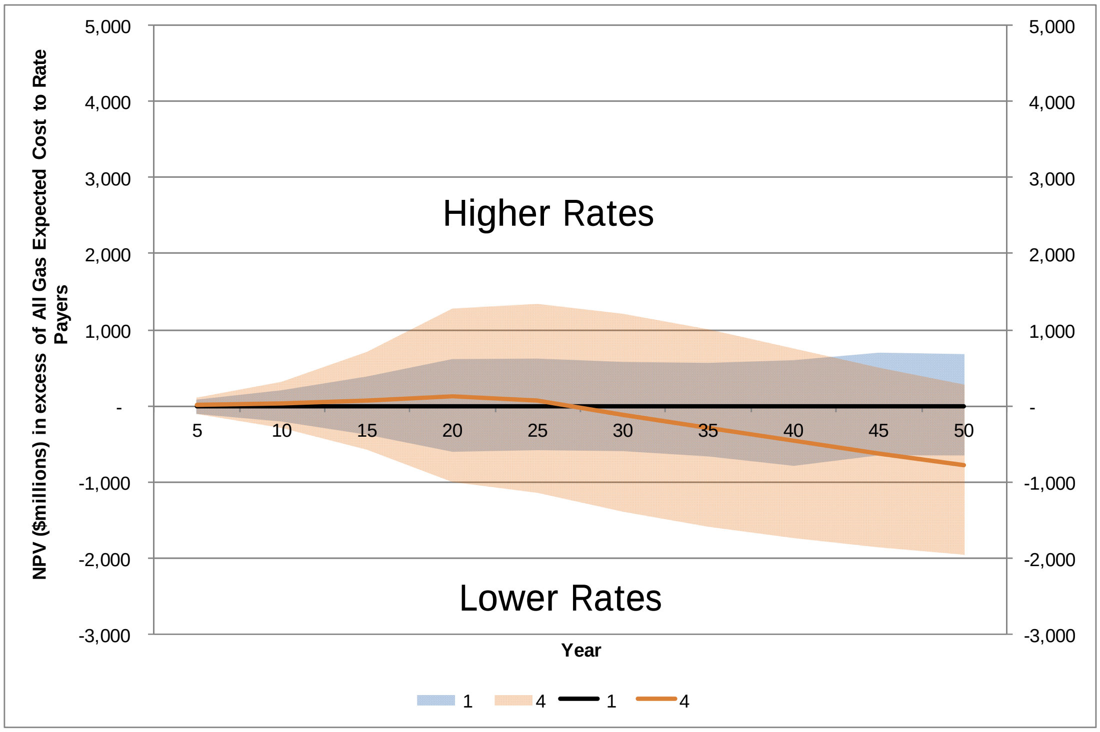


Figure 17: Plan 4 (K19/Gas/250MW) vs. Plan 14 (PDP) at 5.05% Real Discount Rate - NPV of Incremental Domestic Costs as Compared to Plan 1 (All Gas) Expected Value ($ Millions)

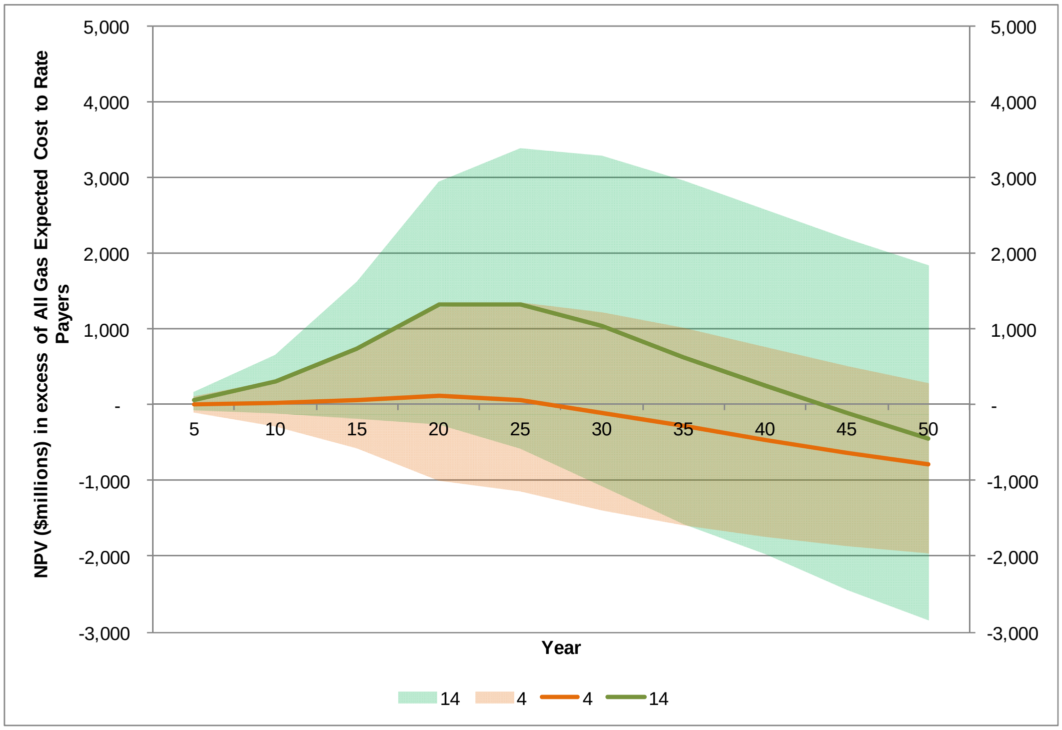
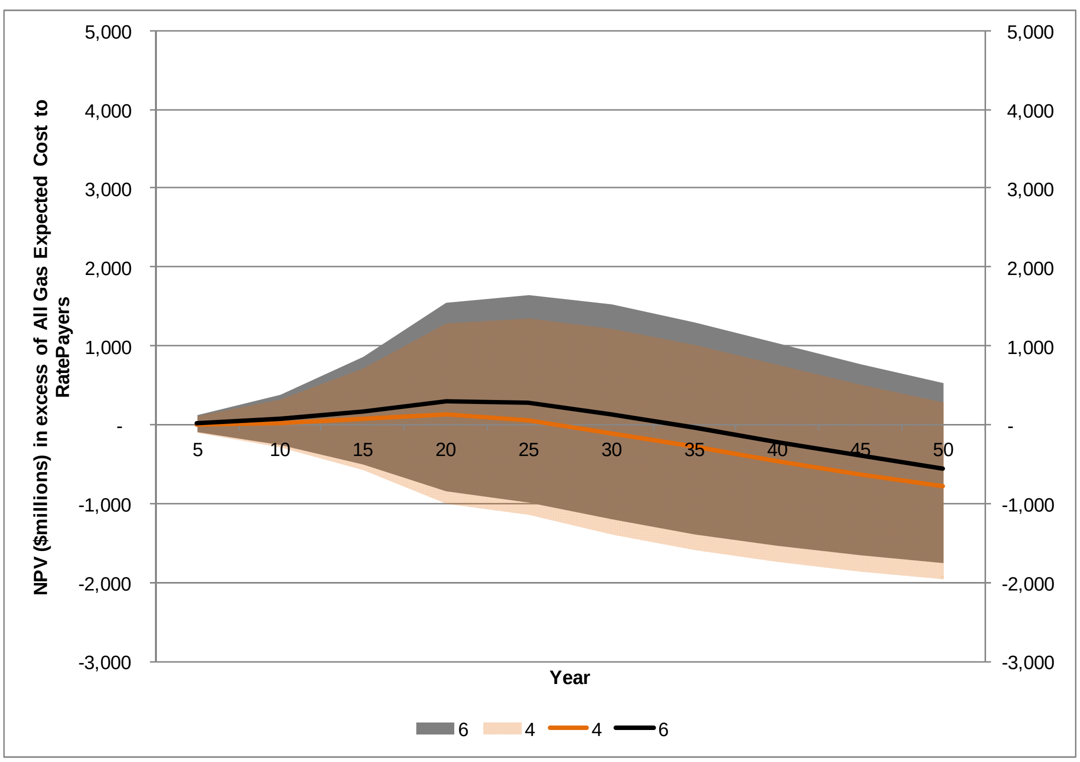


Figure 18: Plan 4 (K19/Gas/250MW) vs. Plan 6 (K19/Gas/750MW) at 5.05% Real Discount Rate - NPV of Incremental Domestic Costs as compared to Plan 1 (All Gas) Expected Value ($ Millions)



In Figure 16 to Figure 18 above, benefits to ratepayers are depicted as lower values – downward on the charts, while increased costs to ratepayers (higher rates and therefore domestic revenues) are upward.

As can be seen from Figure 16:

- Plan 4 (K19/Gas/250MW) provides a wider range of risks to ratepayers than Plan 1 (All Gas) illustrated by the wider orange cone than the blue cone. This includes both upside as well as downside risks.
- Plan 4 (K19/Gas/250MW) does not have a preferential EV for the first 20 years (it is very similar to Plan 1 (All Gas)), but begins to achieve ratepayer benefits (lower values on the graph) over the years 30 through 50, represented by the orange line dropping below the X axis (the zero value in the Figure – which is the EV of Plan 1 (All Gas).

Figure 17 however, shows the comparison of Plan 14 (PDP) with Plan 4 (K19/Gas/250MW). This Figure retains the EV of Plan 1 (All Gas) as the x axis (the horizontal $0 value).

- While Plan 14 has somewhat more potential for a positive upside in the last 15 years (the small green triangle at the lower right corner of Figure 17), it has significantly more risk for a downside outcome during the entire horizon (the green band across the top of Figure 17).
- Plan 14 (PDP) also has a higher EV (higher level of rates) throughout the period - the EV does not ever exceed the benefits that could be secured from Plan 4 (K19/Gas/250MW). This is shown by the green line being above the orange line throughout the graph.
- At its worst, Plan 14 (PDP) results in an expected cost to ratepayers of over $1 billion NPV (which is the value at the 20 year mark), and there is a potential for this value to be as high as $3 billion NPV as compared to the x-axis (the Plan 1 (All Gas) value)) and over $2 billion higher than the worst P10 outcomes under Plan 4 (the highest boundary of the orange cone).
- For Plan 14 (PDP), this shows that the upside for years up to 25 is neutral at best (the best case lower bound of the green cone does not exceed the lower boundary of the orange cone, and typically does not even reach the upside benefits of Plan 4 (K19/Gas/250MW)).

This risk profile does not support Plan 14 (PDP) as an optimum choice for ratepayers.

Figure 18 shows the comparison of Plan 6 (K19/Gas/750MW) with Plan 4 (K19/Gas/250MW), essentially showing the difference between pursuing a 750MW or 250MW US Interconnection to ratepayers. The results are very similar across all years, with Plan 4 (K19/Gas/250MW) offering slightly more potential benefit and Plan 6 (K19/Gas/750MW) offering slightly more potential cost to ratepayers. Since both plans follow very similar risk profiles, Plan 6 (K19/Gas/750MW) is not further graphed in this appendix.

4.2 RATEPAYER IMPACTS UNDER LOW ENERGY PRICES

One feature of the Scenario development conducted by Hydro is that different weightings can be assigned to the various HIGH, REF and LOW conditions (new conditions cannot be developed). Hydro has provided detailed rationale in Appendix 9.3 regarding its selection of the weightings used to develop the probabilities of occurrence for each Scenario, which allows for Sensitivities to be assessed using different weightings.

As an analytical exercise, the above ratepayer cone graphs were re-weighted to keep all economic/interest and capital cost projections consistent, but to weight the energy prices (i.e. export revenues, gas prices) as guaranteed LOW conditions (100% weighting). This results in a recalculation of the cumulative probabilities, percentile distributions and expected values, as shown for example in Table 5 below (for Plan 1 (All Gas)) and Table 6 (for all plans). As can be seen from Table 5, this takes the cumulative probabilities and percentile distribution analysis and spreads it over the nine scenarios that contain the low energy prices, ignoring all other scenarios (assigned 0% probability of occurrence).

It is important to note that this approach removes some of the richness of the data set. A result of this change is that EVs continue to be easily calculated, but P10 and P90 values can be somewhat more volatile and as such the graphs tend to have rougher lines and ranges than under the full 27 scenario analysis.

Table 5: Transforming Scenario Probabilities into Cumulative Probabilities and Percentile Distributions ($ Millions) – for Low Energy Price Scenarios - 50 year Financial Analysis

Probabilities	Plan 1 (All Gas) NPV of Rates	Cumulative Probabilities	Percentile Distribution
3.00%	39,149	3.00%	
0.00%	39,304	3.00%	
7.50%	39,542	6.75%	39,638
0.00%	39,653	10.50%	
0.00%	39,696	10.50%	
10.00%	39,993	15.50%	
4.50%	40,020	22.75%	
0.00%	40,048	25.00%	
0.00%	40,084	25.00%	40,084
7.00%	40,173	28.50%	
0.00%	40,179	32.00%	
0.00%	40,263	32.00%	
0.00%	40,427	32.00%	
25.00%	40,430	44.50%	40,469
0.00%	40,519	57.00%	
0.00%	40,527	57.00%	
17.50%	40,639	65.75%	
0.00%	40,642	74.50%	
0.00%	40,716	74.50%	
0.00%	40,857	74.50%	40,865
15.00%	40,982	82.00%	
0.00%	41,057	89.50%	
0.00%	41,108	89.50%	41,120
10.50%	41,236	94.75%	
0.00%	41,316	100.00%	
0.00%	41,408	100.00%	
0.00%	41,696	100.00%	
Exp. Value	**40,449**	100.00%	

Table 6: Probabilistic Analysis for Ratepayer Revenues ($ Millions) – For Low Energy Price Scenarios - 50 year Financial Analysis

	Pathway 1	Pathway 2		Pathway 3		Pathway 4		Pathway 5
NPV of Ratepayer Revenues ($Millions)	Plan 1: All Gas	Plan 7: SCGT/C26	Plan 2: K22/Gas	Plan 4: K19/Gas24/250MW	Plan 13: K19/C25/250MW	Plan 6: K19/Gas31/750MW	Plan 12: K19/C31/750MW	Plan 14: PDP
Expected Value	40,449	41,617	40,833	40,667	42,402	40,905	42,214	42,033
10th Percentile - "Risk"	39,638	40,372	39,956	39,547	41,103	39,758	41,091	40,827
25th Percentile	40,084	41,337	40,430	40,187	41,804	40,446	41,527	41,328
50th Percentile	40,469	41,694	40,866	40,695	42,473	40,930	42,271	42,101
75th Percentile	40,865	42,127	40,933	41,202	43,134	41,439	42,923	42,785
90th Percentile - "Reward"	41,120	42,529	41,635	41,607	43,711	41,860	43,475	43,390
Expected Value Difference from All Gas	-	1,168	385	218	1,953	456	1,765	1,585

For the low energy price sensitivity (i.e. low export revenues but also low gas prices), the overall cost to ratepayers is higher, but still within less than 5% impact compared to analyses using all energy prices (with all energy prices, the 50 year NPV of rates ranged from $39.8 billion to $40.6 billion per Table 4; with low energy process the range is from $40.4 billion to $42.4 billion per Table 6). This is mostly due to the overall size of Manitoba Hydro's existing system and loads, in comparison to the proposed additions of generation and exports under each Plan.

Figure 19 through Figure 22 show the results under the low price Scenario for Plan 4 (K19/Gas/250MW) and Plan 14 (PDP), first on total rates, and second on incremental rates over and above the Plan 1 (All Gas) EV.

Figure 19: NPV Total Amount Paid in Rates at 5.05% Real Discount Rate
Plan 1 (All Gas) vs. 4 (K19/Gas/250MW) – Low Energy Price Scenarios ($ Millions)

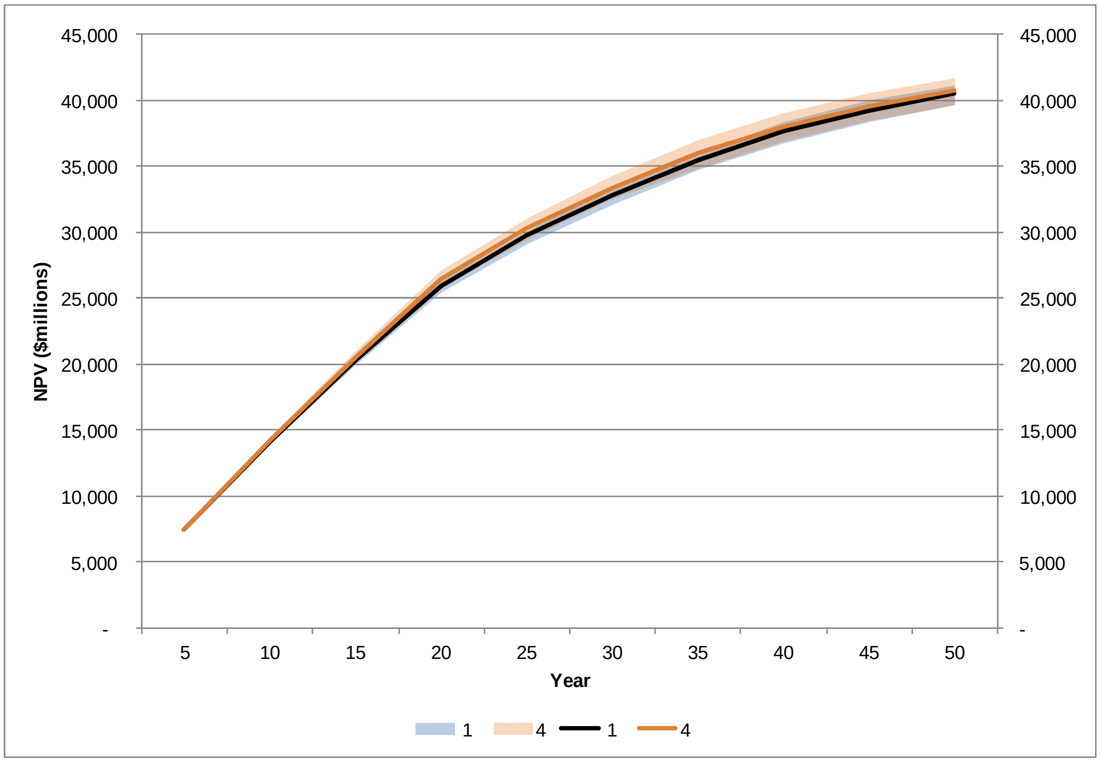


Figure 20: NPV Total Amount Paid in Rates at 5.05% Real Discount Rate Plan 4 (K19/Gas/250MW) vs. 14 (PDP) – Low Energy Price Scenarios ($ Millions)

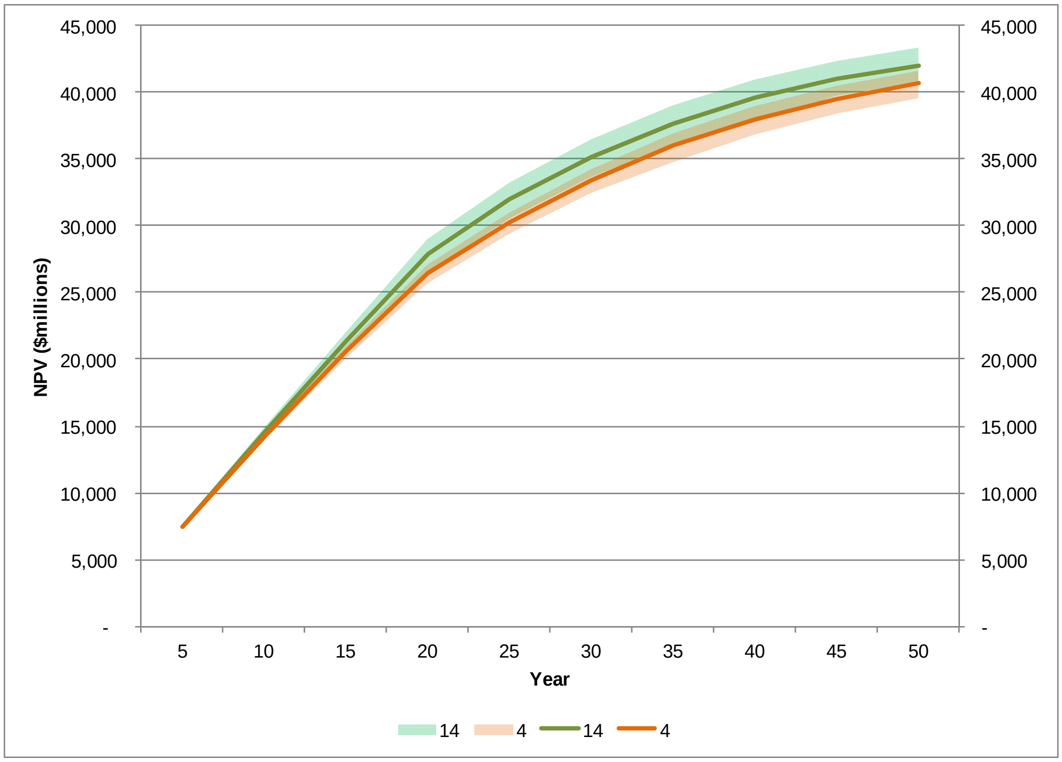


Figure 21: Plan 1 (All Gas) vs. Plan 4 (K19/Gas/250MW) at 5.05% Real Discount Rate- NPV of Incremental Domestic Costs as compared to Plan 1 (All Gas) Expected Value - Low Energy Price Scenarios ($ Millions)

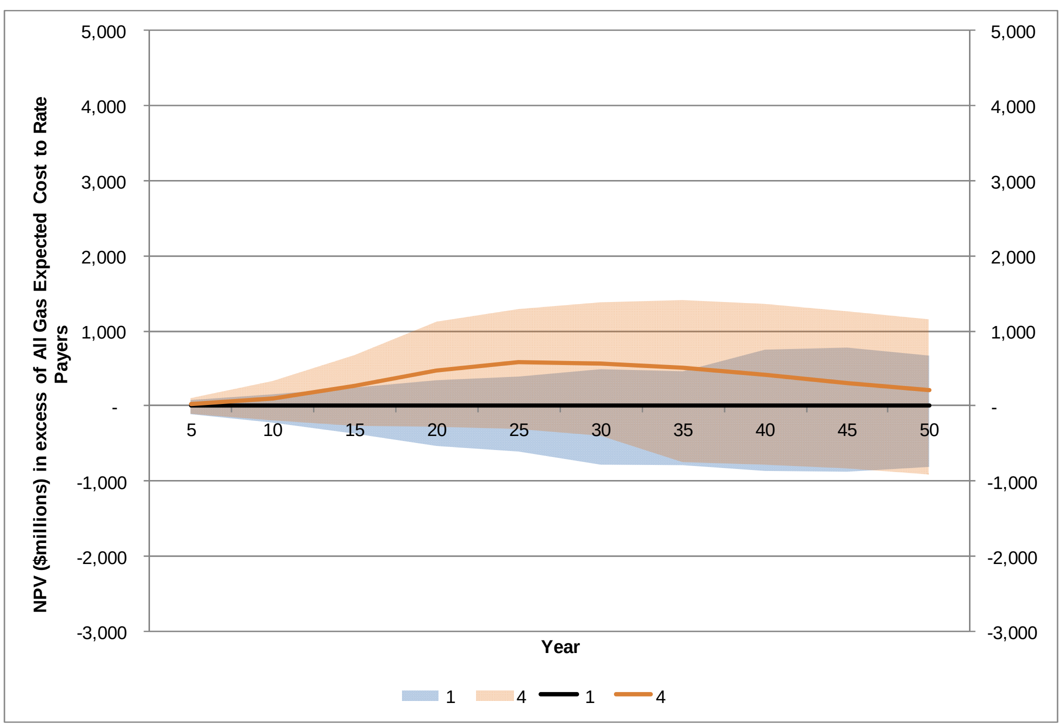
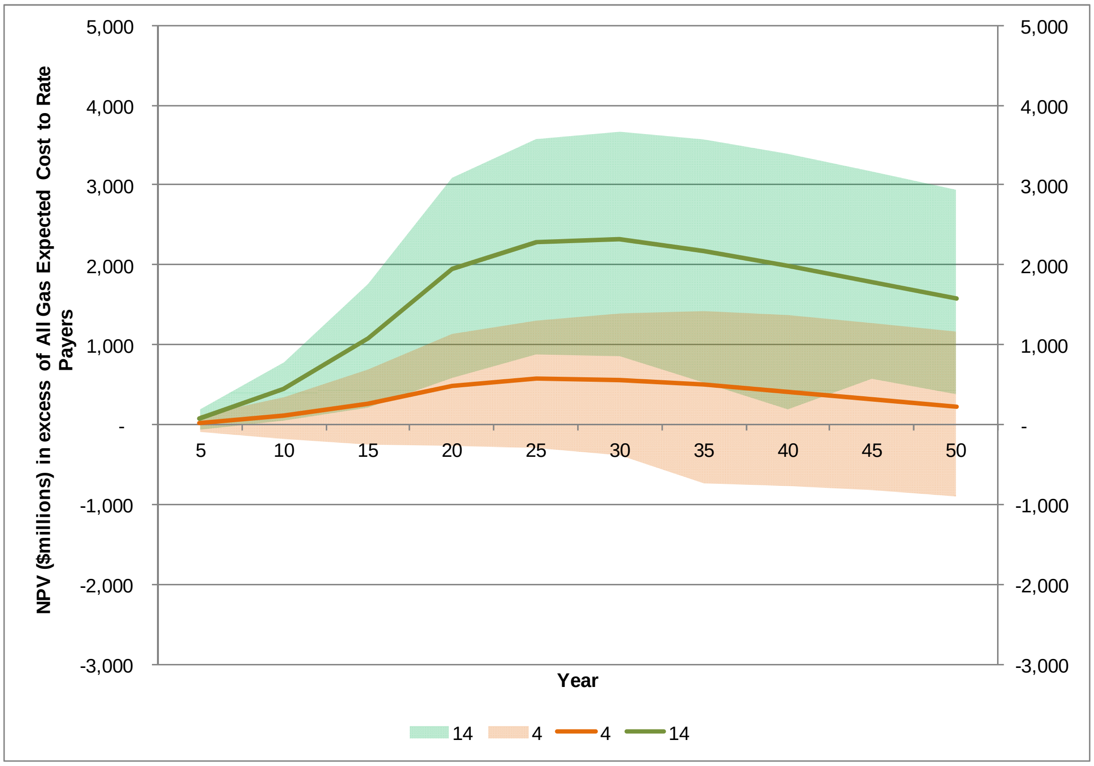


Figure 22: Plan 4 (K19/Gas/250MW) vs. Plan 14 (PDP) at 5.05% Real Discount Rate- NPV of Incremental Domestic Costs as compared to Plan 1 (All Gas) Expected Value – Low Energy Price Scenarios ($ Millions)



As can be seen in the above 4 figures, all of the plans assessed have a wider distribution of outcomes than was the case when modelling all 27 Scenarios in Section 4:

- Plan 1 (All Gas) and Plan 4 (K19/Gas/250MW) are much less affected by the low price scenario than Plan 14 (PDP).
- If a low price scenario were the only future to be modelled, Plan 4 (K19/Gas/250MW) would likely not be a preferred selection over Plan 1 (All Gas), as Figure 21 demonstrates that Plan 4 (K19/Gas/250MW) has a higher EV of rates, a further risk of higher rates, and a low range of probability for lower rates.
- However this analysis is not intended to test low prices as a credible scenario, only to test as a downside sensitivity. As a sensitivity test off of the original assumptions, Plan 4 (K19/Gas/250MW) is not as adversely affected by low export prices as may have been originally assumed. The outcome may be suboptimal compared to Plan 1 (All Gas), but the impacts under this analysis are not disastrous for ratepayers. Further consideration of such matters as the Net Income and the risks that arise under droughts would need to be considered, but the basic conclusion is Plan 4 (K19/Gas/250MW) is not excessively sensitive to a potential for future low export prices.

In contrast, the results shown in Figure 22 are not positive for Plan 14 (PDP).

- Under this low export price sensitivity, Plan 14 exhibits significantly higher rates under basically all conditions than compared to Plan 1 (All Gas) and Plan 4 (K19/Gas/250MW). The differences are material (>$2 billion NPV), sustained throughout the time horizon and without any redeeming upside.

Absent a way to improve the Plan 14 (PDP) downside protection (either from improved assumptions based on updated market conditions, or from changes to the distribution of benefits with other parties) Figure 17 through Figure 22 combined suggest a compelling basis to reject Plan 14 (PDP) for reasons of insufficient benefits and excessive exposure to low export price risks for ratepayers.

5.0 GOVERNMENT BENEFITS

Similar to the ability to model the situation for each Plan and Scenario to ratepayers, the financial forecasts provide the ability to analyze the impacts of each plan on Government.

The following Table 7 shows the present value of benefits to Government over 50 years compared with Plan 1 (All gas) of the same scenario, similar to Manitoba Hydro's Table 2 from the NFAT Business Case Executive Summary, including the probabilities of occurrence for each scenario along the right hand side of the Table[16]. This includes all payments to Government, all growth in Shareholder's Equity and all Non-Controlling Interest (payments to First Nation government partners as investors). This does not include benefits to government from other sources such as income tax on workers employed on Hydro projects, or from indirect impacts such as changes in the level of Manitoba economic activity that arise from higher or lower rate levels and the resulting wealth of Manitobans.

[16] Page 23 of Manitoba Hydro's NFAT Business Case: Executive Summary.

Table 7: Net Present Value of Government Benefits As Compared to Plan 1 (All Gas) Over 50 Years – 5.05% Real Discount Rate ($ Millions)

			Pathway 1	Pathway 2		Pathway 3		Pathway 4		Pathway 5	
Energy Prices	Econ.	Capital Costs	1	7	2	4	13	6	12	14	Probability
Low	Low	High	0	2,174	1,975	1,961	4,220	1,976	4,138	4,319	1.35%
Low	Low	Ref	0	2,064	1,836	1,821	3,949	1,836	3,854	4,031	2.25%
Low	Low	Low	0	1,687	1,481	1,445	3,442	1,466	3,337	3,504	0.90%
Low	Ref	High	0	2,209	1,927	1,844	4,174	1,834	4,154	4,244	4.50%
Low	Ref	Ref	0	2,091	1,798	1,743	3,904	1,712	3,869	3,954	7.50%
Low	Ref	Low	0	1,995	1,747	1,641	3,697	1,655	3,653	3,733	3.00%
Low	High	High	0	2,247	1,915	1,663	4,047	1,626	4,104	4,091	3.15%
Low	High	Ref	0	2,116	1,808	1,574	3,821	1,551	3,845	3,843	5.25%
Low	High	Low	0	2,029	1,748	1,508	3,617	1,512	3,652	3,628	2.10%
Ref	Low	High	0	2,118	1,949	1,965	4,193	1,988	4,157	4,265	2.48%
Ref	Low	Ref	0	2,009	1,825	1,833	3,914	1,858	5,110	3,977	4.12%
Ref	Low	Low	0	1,908	1,740	1,741	3,679	1,774	3,642	3,732	1.65%
Ref	Ref	High	0	2,144	1,973	1,883	4,144	1,880	4,194	4,196	8.25%
Ref	Ref	Ref	0	2,028	1,832	1,726	3,877	1,738	3,902	3,894	13.75%
Ref	Ref	Low	0	1,933	1,761	1,666	3,662	1,685	3,681	3,685	5.50%
Ref	High	High	0	2,162	1,966	1,754	4,058	1,731	4,209	4,074	5.78%
Ref	High	Ref	0	2,034	1,835	1,629	3,789	1,612	3,922	3,787	9.63%
Ref	High	Low	0	1,937	1,790	1,557	3,586	1,560	3,703	3,572	3.85%
High	Low	High	0	2,070	1,969	2,007	4,175	2,027	4,195	4,202	0.68%
High	Low	Ref	0	1,949	1,845	1,865	3,890	1,884	3,899	3,931	1.13%
High	Low	Low	0	1,847	1,767	1,778	3,679	1,805	3,678	3,704	0.45%
High	Ref	High	0	2,071	1,948	1,905	4,109	1,902	4,216	4,137	2.25%
High	Ref	Ref	0	1,905	1,834	1,781	3,844	1,786	3,937	3,850	3.75%
High	Ref	Low	0	1,846	1,763	1,705	3,630	1,717	3,718	3,629	1.50%
High	High	High	0	2,056	1,965	1,756	3,958	1,715	4,204	3,955	1.58%
High	High	Ref	0	1,948	1,853	1,666	3,743	1,645	3,967	3,718	2.63%
High	High	Low	0	1,851	1,785	1,609	3,543	1,604	3,735	3,509	1.05%

The following Table 8 shows the present value benefits to Government for each plan compared with the Plan 1 (All Gas) REF-REF-REF, similar to Manitoba Hydro's Table 10.5 from Chapter 10 of the NFAT Business Case [17].

[17] Manitoba Hydro NFAT Business Case, Chapter 10: Economic Uncertainty Analysis – Probabilistic Analysis and Sensitivities, page 17.

Table 8: Net Present Value of Government Benefits as Compared to Plan 1 (All Gas) REF-REF-REF Over 50 Years – 5.05% Real Discount Rate ($ Millions)

			Pathway 1	Pathway 2		Pathway 3		Pathway 4		Pathway 5	
Energy Prices	Econ.	Capital Costs	1	7	2	4	13	6	12	14	Probability
Low	Low	High	146	2,321	2,121	2,107	4,366	2,123	4,284	4,465	1.35%
Low	Low	Ref	(13)	2,051	1,823	1,808	3,936	1,823	3,841	4,018	2.25%
Low	Low	Low	134	1,821	1,615	1,579	3,576	1,601	3,472	3,638	0.90%
Low	Ref	High	(119)	2,091	1,808	1,725	4,055	1,715	4,035	4,125	4.50%
Low	Ref	Ref	(292)	1,798	1,506	1,451	3,612	1,420	3,577	3,662	7.50%
Low	Ref	Low	(433)	1,562	1,314	1,208	3,264	1,222	3,220	3,300	3.00%
Low	High	High	(515)	1,731	1,400	1,147	3,532	1,111	3,589	3,576	3.15%
Low	High	Ref	(696)	1,420	1,112	878	3,125	855	3,149	3,147	5.25%
Low	High	Low	(856)	1,173	892	653	2,761	656	2,797	2,773	2.10%
Ref	Low	High	410	2,529	2,359	2,375	4,603	2,399	4,567	4,676	2.48%
Ref	Low	Ref	247	2,256	2,072	2,080	4,161	2,105	5,356	4,224	4.12%
Ref	Low	Low	121	2,029	1,861	1,862	3,800	1,895	3,763	3,853	1.65%
Ref	Ref	High	174	2,318	2,147	2,057	4,318	2,055	4,368	4,370	8.25%
Ref	Ref	Ref	0	2,028	1,832	1,726	3,877	1,738	3,902	3,894	13.75%
Ref	Ref	Low	(148)	1,785	1,613	1,518	3,514	1,538	3,533	3,537	5.50%
Ref	High	High	(162)	2,001	1,804	1,593	3,897	1,569	4,047	3,912	5.78%
Ref	High	Ref	(337)	1,697	1,498	1,292	3,453	1,275	3,586	3,450	9.63%
Ref	High	Low	(503)	1,434	1,287	1,054	3,083	1,056	3,199	3,069	3.85%
High	Low	High	645	2,715	2,614	2,652	4,820	2,672	4,840	4,848	0.68%
High	Low	Ref	489	2,437	2,334	2,354	4,379	2,373	4,388	4,420	1.13%
High	Low	Low	356	2,203	2,122	2,134	4,035	2,161	4,034	4,060	0.45%
High	Ref	High	464	2,535	2,411	2,369	4,572	2,365	4,680	4,601	2.25%
High	Ref	Ref	291	2,196	2,125	2,072	4,135	2,076	4,228	4,141	3.75%
High	Ref	Low	148	1,993	1,911	1,853	3,777	1,865	3,865	3,777	1.50%
High	High	High	211	2,267	2,176	1,967	4,169	1,926	4,415	4,166	1.58%
High	High	Ref	14	1,961	1,867	1,679	3,757	1,659	3,981	3,731	2.63%
High	High	Low	(147)	1,703	1,638	1,462	3,396	1,457	3,588	3,362	1.05%

Note that the range of benefits under the plans such as Plan 4 (K19/Gas/250MW), Plan 6 (K19/Gas/750MW) and Plan 14 (PDP) are always positive and better than Plan 1 (All Gas), while Plan 1 (All Gas) shows a risk to Government under certain scenarios that recoveries will be less than the Plan 1 (All Gas) REF-REF-REF baseline value.

The NPV and relative NPV of Government benefits are set out in Figure 23 through Figure 26 below. These figures provide a comparison of both the EV and the risk (P10/P90) to the Government benefits under each Plan and the full range of Scenarios. Of note, each figure shows that there is effectively no risk to Government of achieving higher levels of benefits as plans proceed from Plan 1 (All Gas) to Plan 4 (K19/Gas/250MW) to Plan 14 (PDP).

Figure 23: Plan 1 (All Gas) vs. Plan 4 (K19/Gas/250MW) at 5.05% Real Discount Rate NPV of Government Benefits ($ Millions)

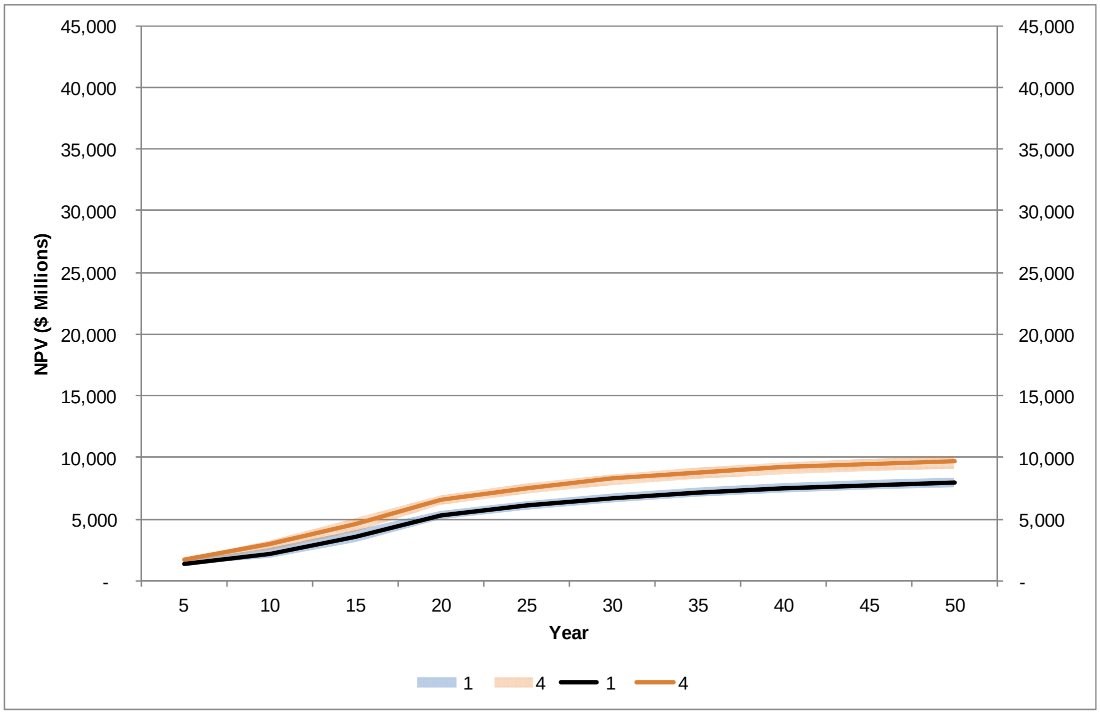


Figure 24: Plan 4 (K19/Gas/250MW) vs. Plan 14 (PDP) at 5.05% Real Discount Rate NPV of Total Government Benefits ($ Millions)

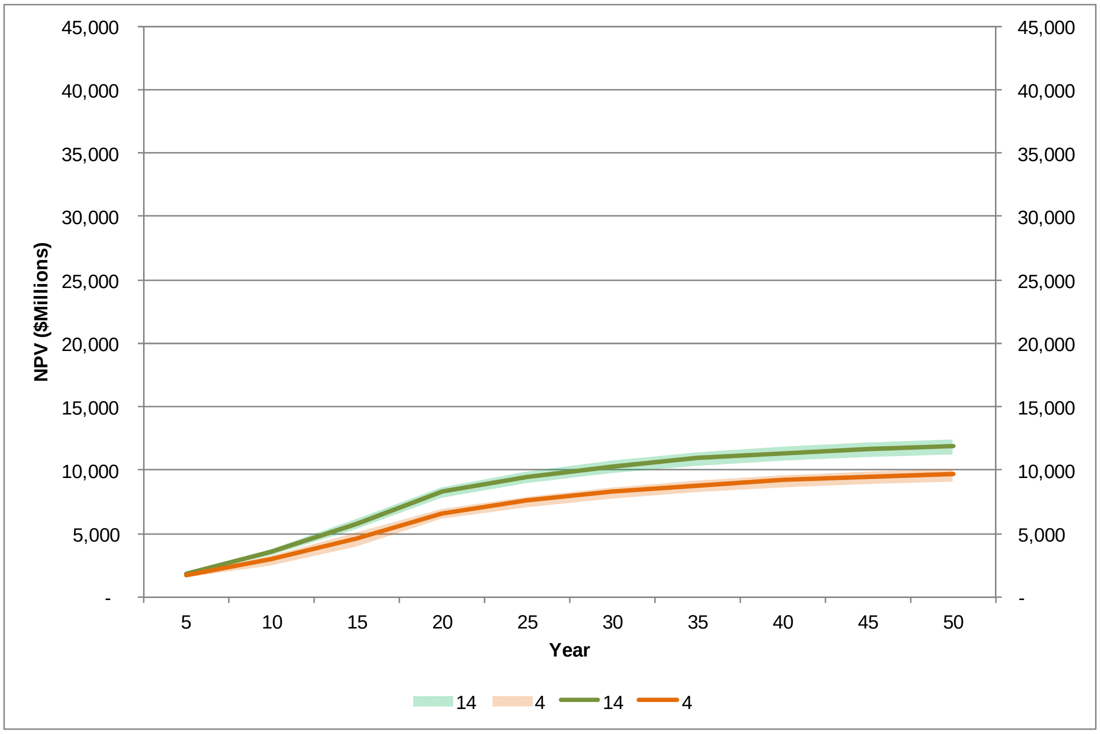


Figure 23 and Figure 24 have been plotted using on the same vertical axis as for ratepayers. This allows for direct comparison with the earlier figures in this Appendix. As this scale shows, the total benefits to Government are a minor subset of the costs charged to ratepayers. This is illustrated by the degree to which Government benefits remains in the lower part of the graph. Total NPV of domestic rates paid equals approximately $40 billion over 50 years, while Government benefits tend towards $8 billion (Plan 1 (All Gas), $10 billion (Plan 4 (K19/Gas/250MW)) or $12 billion (Plan 14 (PDP)).

Also of note, the absolute Government benefits are fairly certain, with little risk of variability regardless of Scenario outcome, shown by the tight range between the P10 and P90 values.

Figure 25: Plan 1 (All Gas) vs. Plan 4 (K19/Gas/250MW) at 5.05% Real Discount Rate
NPV of Incremental Government Benefits as compared to Plan 1 (All Gas)
Expected Value ($ Millions)

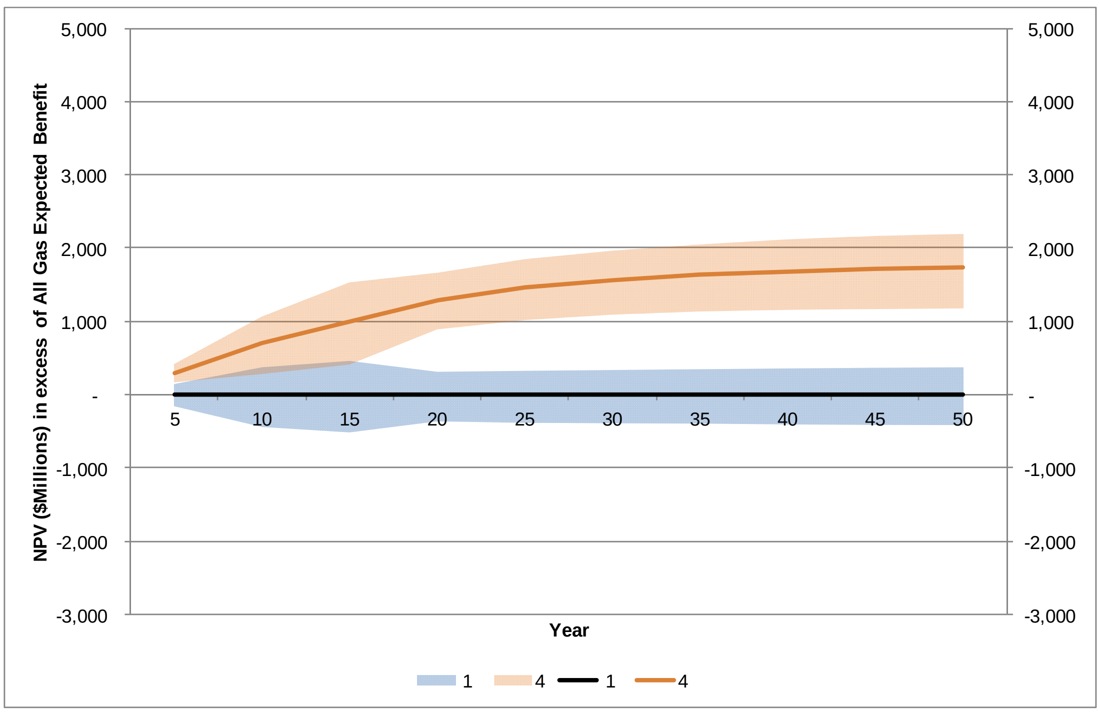
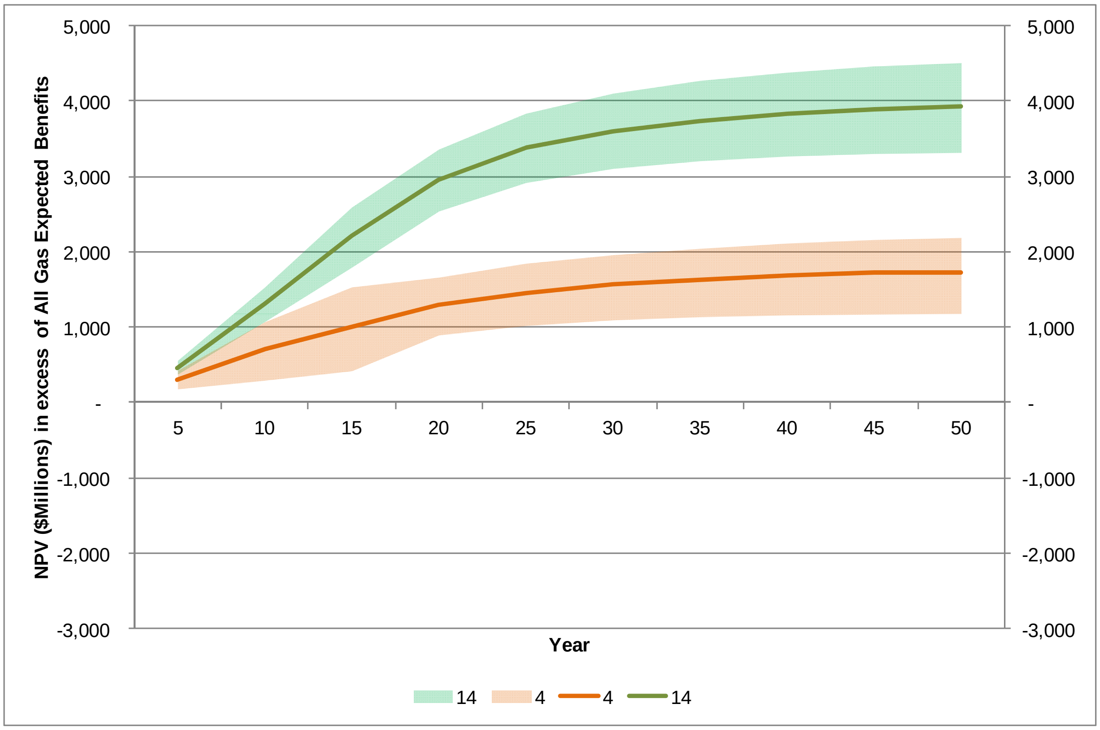


Figure 26: Plan 4 (K19/Gas/250MW) vs. Plan 14 (PDP) at 5.05% Real Discount Rate NPV of Incremental Government Benefits as compared to Plan 1 (All Gas) Expected Value ($ Millions)



Under Plan 1 (All Gas) the level of Government benefits is much lower than under Plan 4 (K19/Gas/250MW) and substantially lower than Plan 14 (PDP). Note as well that the stacking of the Government benefits are dominant through these Plans – even under the worst scenarios presented, the Government benefits under Plan 4 (K19/Gas/250MW) are above the best conditions under Plan 1 (All Gas). A similar conclusion applies for Plan 14 (PDP) versus Plan 4 (K19/Gas/250-MW).

6.0 RATEPAYERS DISCOUNT RATE SENSITIVITIES

All of the above scenarios are based off a real discount rate of 5.05%. This is a reasonable starting point for an analysis to determine the optimum plan for ratepayers. However, this discount rate does not fully represent the time preference of many ratepayer groups or individuals for the horizon being analyzed.

- In particular, with respect to MIPUG concerns, paying higher rates for a sustained period of time (20-25 years) term for benefits in terms of rates in the long-term (out to 25-50 years) is a competing use of funds compared to other places where investments can be made, such as plant expansions, new technology, or expanding markets. Typical corporate planning process will set out threshold rates for return on investments of different types – in many (if not most) cases these rates will be well above 5.05% real.

- At the same time, key long-term building block system assets for a hydro utility reflect a bequest value benefit for the system which can exceed a century. Analyses that include this type of horizon will often seek to test low discount rates to ensure that real and valid multi-generational benefits are not being discounted away.

For this reason, sensitivity analyses were conducted at the extreme levels of a 10.0% real discount rate, and a 1.86% real discount rate.

6.1 RATEPAYER COSTS/BENEFITS AT 1.86% REAL DISCOUNT RATE

The graphs that show the benefits to ratepayers are calculated using the same probabilistic analysis and percentile distribution as shown for the NPVs calculated above. The real discount rate used was 1.86%. Appropriate inflation is added in each different economic Scenario.

As the discount rate has been revised downwards, the NPV values are now reported at much higher levels (as future power bills are given more recognition). As compared to NPV values in the range of $40 billion above, values with the lower discount rate tend towards $70 billion under a low discount rate. This is a proper and expected mathematical outcome, but underlines why comparing different Plans under scenarios using different discount rates should be approached with caution.

Figure 27 to Figure 30 present the results of this analysis in the Cone Graph format.

Figure 27: NPV Total Amount Paid in Rates at 1.86% Real Discount Rate Plan 1 (All Gas) vs. Plan 4 (K19/Gas/250MW) ($ Millions)

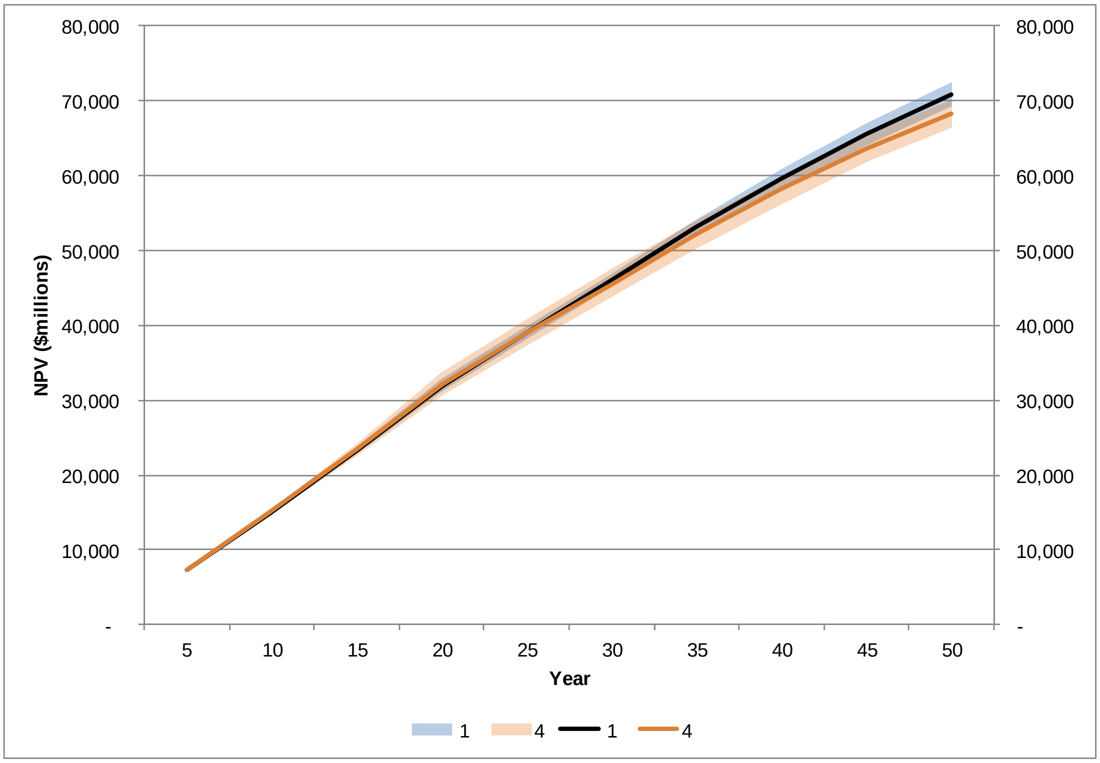


Figure 28: NPV Total Amount Paid in Rates at 1.86% Real Discount Rate Plan 4 (K19/Gas/250MW) vs. Plan 14 (PDP) ($ Millions)

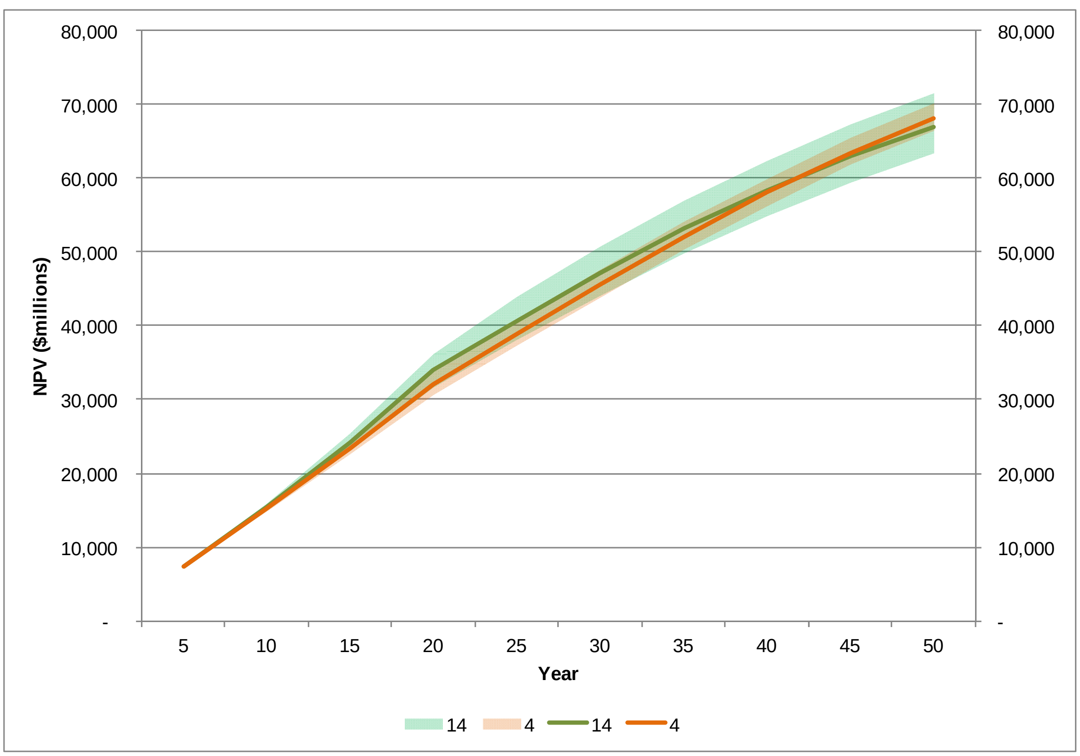


Figure 29: Plan 1 (All Gas) vs. Plan 4 (K19/Gas/250MW) at 1.86% Real Discount Rate- NPV of Incremental Domestic Costs as compared to Plan 1 (All Gas) Expected Value ($ Millions)

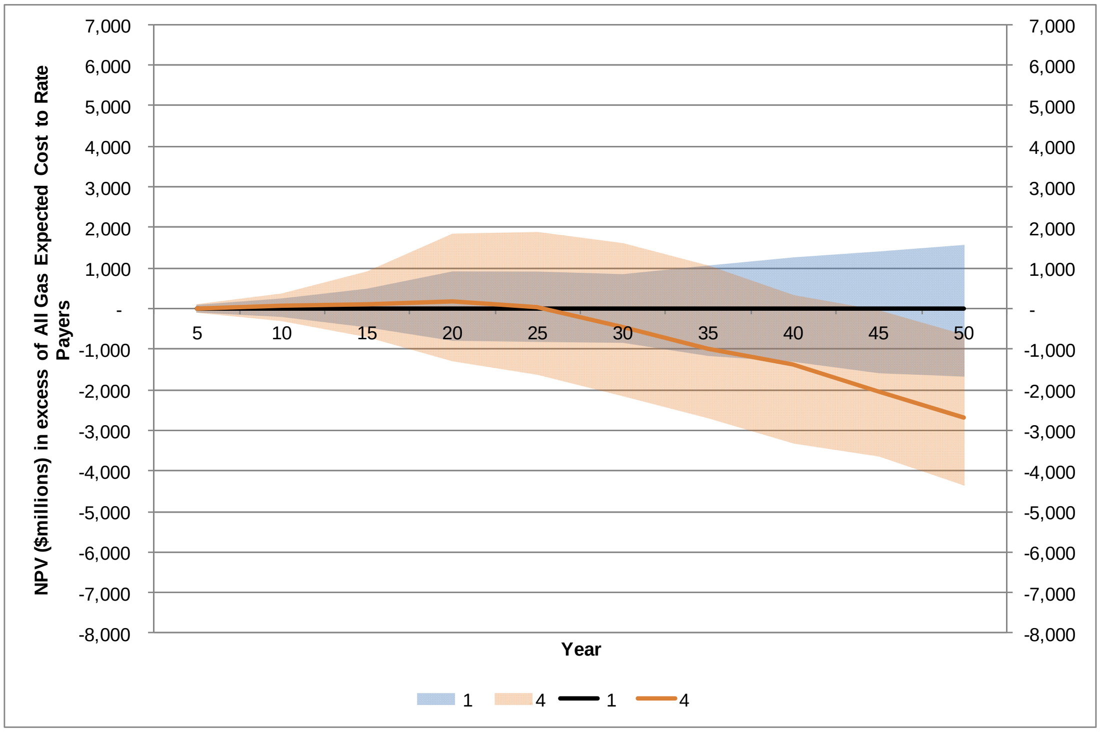
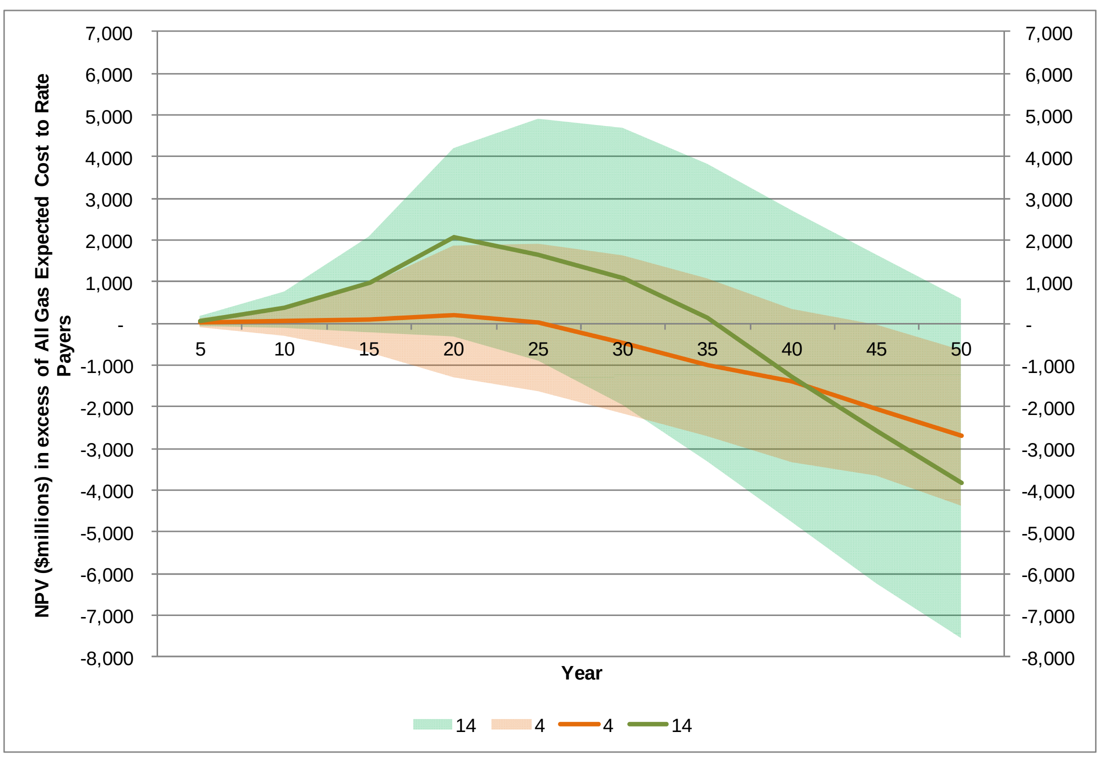


Figure 30: Plan 4 (K19/Gas/250MW) vs. Plan 14 (PDP) at 1.86% Real Discount Rate- NPV of Incremental Domestic Ratepayer Costs as compared to Plan 1 (All Gas) Expected Value ($ Millions)



As shown in Figure 27 to Figure 30, the use of a lower discount rate drives a much greater weighting to future periods. In particular, the conclusions regarding Plan 4 (K19/Gas/250MW) being preferable to Plan 1 (All Gas) are further enhanced in Figure 29.

In contrast, however, Figure 30 shows that adopting a lower discount rate alone is not sufficient to bring Plan 14 (PDP) into contention with Plan 4 (K19/Gas/250MW). Plan 14 (PDP) retains a risk of high rate levels throughout the horizon, has a higher EV except over very long horizons (40 years or more), has only limited upside or best case potential arising well into the future (30 years or more) and there remains notable downside risk even at the 50 year horizon.

From a utility planning perspective, the real discount rate of 1.86% is only relevant with respect to testing whether a significant "bequest value" arises that is otherwise ignored at higher discount rates. Based on the above analysis, the bequest value is present, but sufficiently limited even by year 50 that it does not provide a compelling alternative explanation for pursuing Plan 14 (PDP) under the presently forecast Scenarios.

6.2 RATEPAYER COSTS/BENEFITS AT 10% REAL DISCOUNT RATE

In comparison to the above analysis, reviewing Plans 1 (All Gas), 4 (K19/Gas/250MW) and 14 (PDP) with a high discount rate serves to put a premium on the ratepayer commitments (through higher rates) in the early years (e.g., up to year 25 or more). Choosing a high discount rate can be consistent with a high degree of scepticism with the extremely long range forecasts, and with ratepayers who have much better options for use of funds, such as good investment opportunities or paying off high-cost debt.

This is also consistent with the concept that the choice between Plan 1 (All Gas) and the larger plans (e.g., with Keeyask and/or Conawapa) is more than a difference of degrees – it is a difference of vision. Plan 1 (All Gas) is the base assumption as it involves the least commitments of capital spending in planning period. Plans larger than this are optional for Hydro, and should be pursued only if they meet with the desired vision of Manitobans, including satisfying a high threshold for expected financial benefits (such as 10% real discount rates).

Figure 31 and Figure 34 provide the results of the analysis of high discount rate scenarios.

Figure 31: NPV Total Amount Paid in Rates at 10% Real Discount Rate Plan 1 (All Gas) vs. Plan 4 (K19/Gas/250MW) ($ Millions)

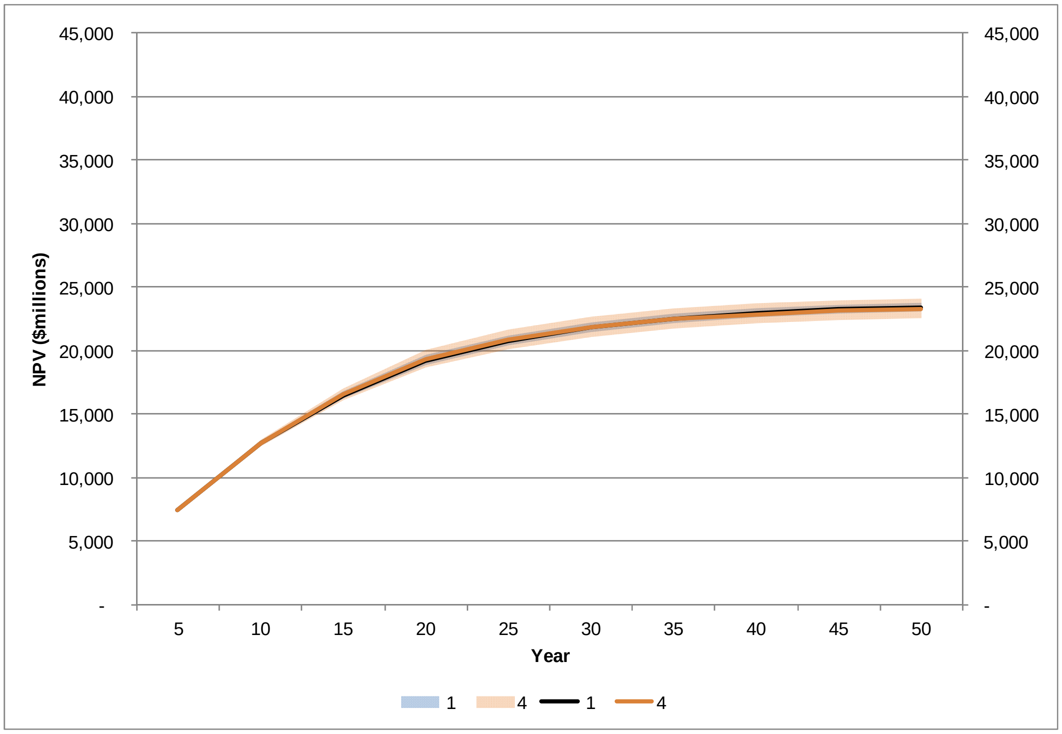


Figure 32: NPV Total Amount Paid in Rates at 10% Real Discount Rate Plan 4 (K19/Gas/250MW) VS. Plan 14 (PDP) ($ Millions)

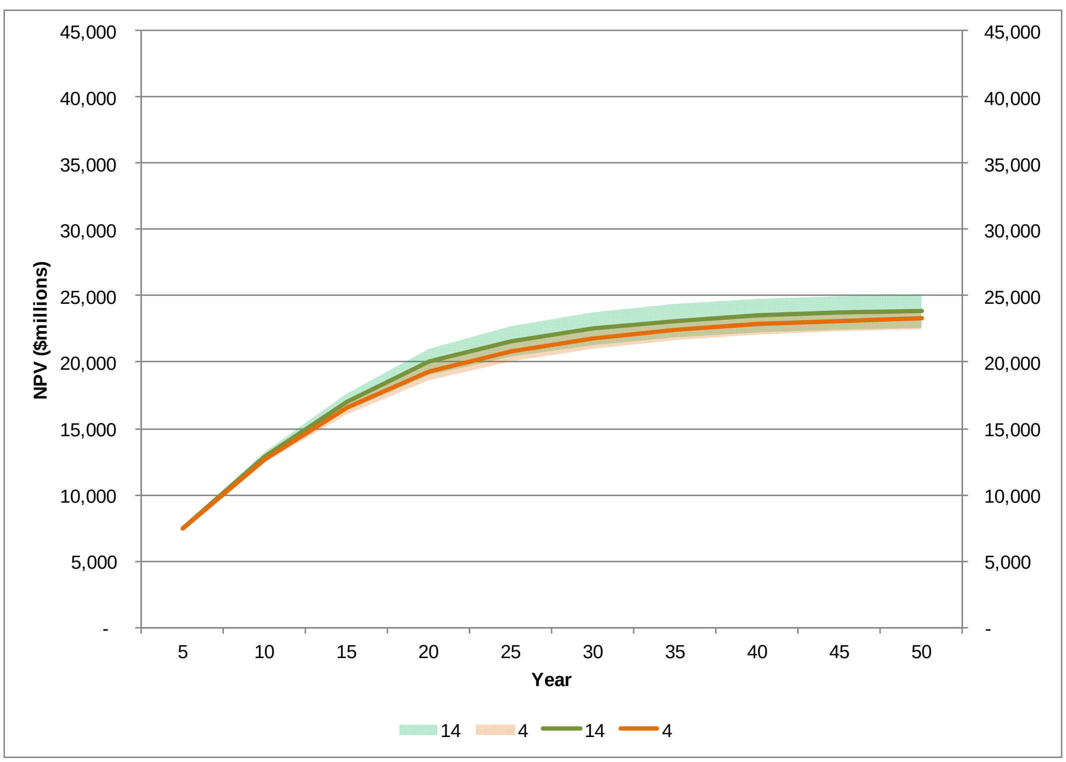


Figure 33: Plan 1 (All Gas) vs. Plan 4 (K19/Gas/250MW) at 10% Real Discount Rate- NPV of Incremental Domestic Costs as compared to Plan 1 (All Gas) Expected Value ($ Millions)

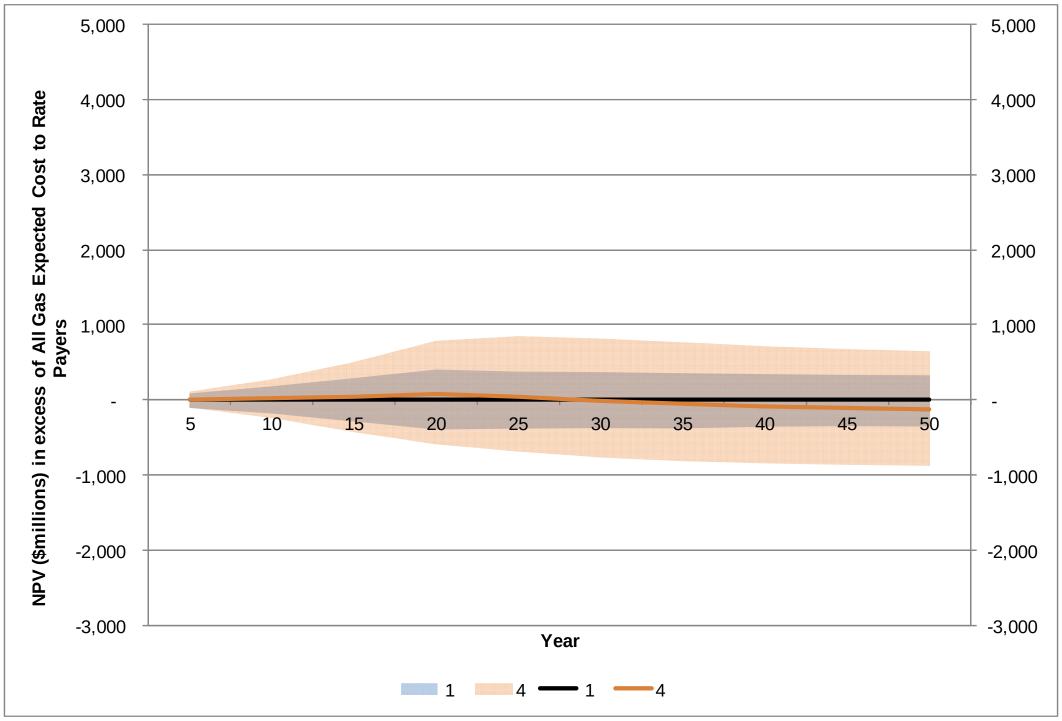


Figure 34: Plan 4 (K19/Gas/250MW) vs. Plan 14 (PDP) at 10% Real Discount Rate- NPV of Incremental Domestic Costs as compared to Plan 1 (All Gas) Expected Value - ($ Millions)

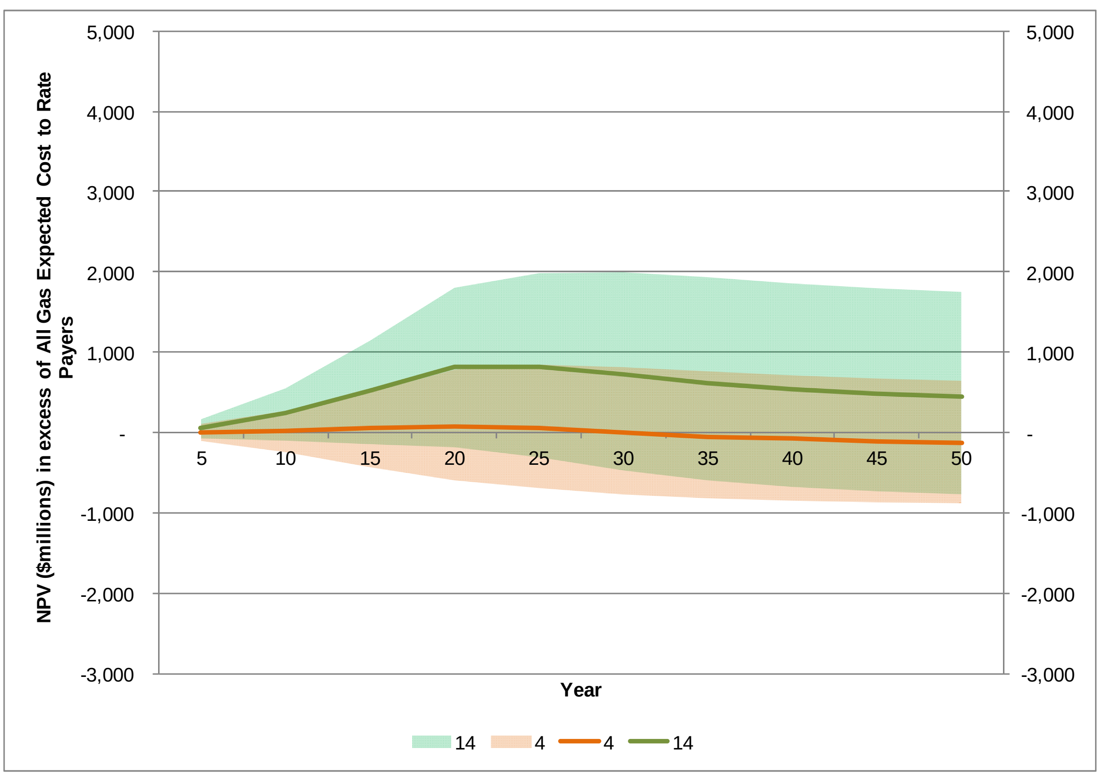


Figure 33 plots the comparison of Plan 4 (K19/Gas/250MW) with the expected value of Plan 1 (All Gas).

- The figures show that Plan 4 remains a viable option even under a high discount rate threshold.
- Plan 4 (K19/Gas/250MW) retains some risks (both upside and downside) compared to Plan 1 (All Gas), but the range is still relatively tight.

Under these circumstances the decision between Plan 1 and Plan 4 is not conclusively driven to either plan under the high discount rate. The decision regarding whether to pursue the vision consistent with a more interconnected system (Opportunity-Based) or with a more limited commitment of capital today (Need-Based) would therefore be expected to turn on less tangible or quantifiable benefits of the two Plans (i.e., outside of financial considerations).

In contrast, Plan 14 (PDP) as per Figure 34 above is not aided by the testing of a high discount rate sensitivity.

- The expected value NPV of rates remains above the rate levels paid under Plan 4 (K19/Gas/250MW) for all future periods.

This analysis would further support that Plan 14 (PDP) provides insufficient benefits to customers to pursue based on current conditions.

6.3 PLAN 14 (PDP) RATEPAYER IMPACT MITIGATION CONCEPT – REBALANCING BENEFITS WITH PROVINCIAL GOVERNMENT

As a result of the Financial Analysis review of benefits for ratepayers and the Provincial Government, it is apparent that the benefits to Manitoba overall (for ratepayers and Government are combined) as a result of Plan 14 (PDP) are high. For example, the situation with respect to the provincial Government and ratepayers is as follows (with reference to the earlier Figures 26 (Government) and 19 (Ratepayers) – the same values are shown below in Tables 9 and 10):

- **Government:** The green area of Figure 26 above (which sets out the Plan 14 (PDP) NPV of Incremental Government Benefits) highlights how Plan 14 (PDP) provides in excess of $3 billion NPV benefits to Governments over the first 20 years (the green line – this is not counting other non-utility items such as worker income taxes) which increases through year 30, and finally progresses up to $4 billion over 50 years, with relatively little risk (+/-$0.5 billion - the green shading).
- **Ratepayers:** In contrast Figure 17 above (which sets out the Plan 14 (PDP) - NPV of Incremental Domestic Ratepayer Costs) shows the ratepayer effects of Plan 14 (PDP) as being approximately a $1 billion *adverse* impact on ratepayers at year 20 (the green line; also note the

green shading showing this value to be +/-$1.5 billion) which improves somewhat through year 30, and reaches a small beneficial impact by year 50 of less than $0.5 billion (+/- $2 billion). This is still almost $0.5 billion less benefits than Plan 4 offers (K19/Gas/250MW).

Table 9 and Table 10 show the NPV benefits of the plans at the 30 years and 50 years (the years 2041/42 and 2061/62 respectively). The tables notes the EV benefits separately to ratepayers and Government (negative values are net costs), as well as the combined values. Tables 9 and 10 are indexed to the Expected Value of Plan 1 (All Gas) and show the NPV values at both the expected value level (in bold) and the variability from P10 to P90 for each Plan.

Table 9: NPV of Total Benefits to Ratepayers and Government at Year 30 (2041/42) for Financial Analysis ($ Millions) at 5.05% Real Discount Rate

NPV of (Cost)/Benefit at 30 years ($ Millions) [P10/P90]	**Pthwy 1**	**Pthwy 2**		**Pthwy 3**		**Pthwy 4**		**Pthwy 5**
	Plan 1	**Plan 7**	**Plan 2**	**Plan 4**	**Plan 13**	**Plan 6**	**Plan 12**	**Plan 14**
Ratepayer Benefit	**0** [(586)/593]	**(850)** [(2,316)/574]	**(164)** [(1,376)/1,083]	**110** [(1,215)/1,395]	**(1,263)** [(3,658)/964]	**(138)** [(1,524)/1,204]	**(1,078)** [(3,151)/840]	**(1,031)** [(3,277)/1,074]
Government Benefit	**0** [(384)/344]	**1,896** [1,492/2,229]	**1,666** [1,300/1,996]	**1,562** [1,093/1,959]	**3,577** [3,037/4,027]	**1,572** [1,100/1,989]	**3,601** [3,018/4,086]	**3,598** [3,093/4,089]
Total Plan Benefits	**0** [(970)/937]	**1,046** [(824)/2,803]	**1,502** [(76)/3,079]	**1,672** [(122)/3,354]	**2,314** [(621)/4,991]	**1,434** [(424)/3,193]	**2,523** [(133)/4,926]	**2,567** [(184)/5,163]

The notable aspect of the results in Table 9 is that on a combined basis the total plan benefits even to year 30 (2041/42) favour Plan 14 (PDP). The year 2041/42 is approximately 15 years after Conawapa is scheduled to come into service in Plan 14 (PDP). The issues for ratepayers arise due to the large degree of charges paid to the provincial Government over the 30 year period. In particular, the relative adverse outcomes for ratepayers contrast with the large provincial Government charges over this period. This disparity supports a concept of rebalancing the impacts between ratepayers and Government through a revised relationship.

Table 10 sets out the same information at year 50.

Table 10: NPV of Total Benefits to Ratepayers and Government at Year 50 (2061/62) for Complete Financial Analysis ($ Millions) at 5.05% Real Discount Rate

NPV of (Cost)/Benefit at 50 years ($ Millions) [P10/P90]	**Pthwy 1**	**Pthwy 2**		**Pthwy 3**		**Pthwy 4**		**Pthwy 5**
	Plan 1	**Plan 7**	**Plan 2**	**Plan 4**	**Plan 13**	**Plan 6**	**Plan 12**	**Plan 14**
Ratepayer Benefit	**0** [(688)/648]	**(12)** [(1,412)/ 1,353]	**444** [(393)/ 1,553]	**780** [(282)/ 1,960]	**105** [(2,259) /2,631]	**557** [(524)/ 1,760]	**141** [(2,001) /2,434]	**439** [(1,833)/ 2,841]
Government Benefit	**0** [(408)/381]	**2,048** [1,565/ 2,423]	**1,849** [1,396/ 2,264]	**1,731** [1,177/ 2,187]	**3,889** [3,219/ 4,383]	**1,729** [1,171/ 2,211]	**3,986** [3,307/ 4,542]	**3,918** [3,304/ 4,495]
Total Plan Benefit	**0** [(1,096)/ 1,029]	**2,036** [153/ 3,776]	**2,293** [1,003/ 3,817]	**2,511** [895/ 4,147]	**3,994** [960/ 7,014]	**2,286** [647/ 3,971]	**4,127** [1,306/ 6,976]	**4,357** [1,471/ 7,336]

The situation depicted in Table 10 clarifies the long-term trends. That is, over the period from years 30 to 50, the NPV benefits to ratepayers under Plan 14 (PDP) are significant (almost a $1.5 billion improvement from 30 years (Table 9) to 50 years (Table 10)). In short, the tables highlight that a rebalanced relationship with the provincial Government likely need not be a permanent feature, but solely a temporary measure to address at least the early in-service impacts of Conawapa.

A similar conclusion merits consideration for the impacts between Plans 4 (K19/Gas/250MW) which is the best outcome for ratepayers, and Plan 6 (K19/Gas/750MW) which is effectively required if Conawapa is to proceed. Although the benefit sharing through year 30 for Plan 4 (K19/Gas/250MW) is heavily skewed to the provincial Government, this is not in and of itself a sign that a rebalancing of benefits is necessary. In particular, ratepayers do not, under this analysis, appear any worse off under Plan 4 (K19/Gas/250MW) than they do under any other plan. Such a revised balance may be necessary in the event of P10 outcomes (where ratepayers would be adversely impacted to the sum of $1.215 billion NPV, while the provincial Government would continue to benefit $1.093 billion from pursuing this plan). In contrast, Plan 6 (K19/Gas/750MW) is clearly an added investment by ratepayers that provides little prospect, under expected Scenarios, of yielding net benefits. However the decision to pursue the 750 MW line based on decisions made in June 2014 is effectively a precondition for pursuing Plan 14 (PDP).

In short, in order for the entire Manitoba province to capture the upside that Plan 14 (PDP) may bring, there is a need for further consideration about (a) a degree of support outside of rates for the decision to proceed to a 750 MW line, and (b) a rebalanced relationship between ratepayers and the provincial Government covering a period a years after the in-service of Conawapa, in the event it proceeds.

There are many possible concepts for this to be implemented, which will require detailed consideration during the planning phases for Conawapa. One conceptual example is set out below. This option was selected on the basis that is easily modelled, and it clarifies the degree of impact that temporary changes can have on the ratepayer benefits. This NPV scenario was modelled as follows:

a. Calculate the full scope of government cash payment in each year (debt guarantee fees, water rentals, and capital taxes; does not include any effects on shareholder's equity or First Nation partners).

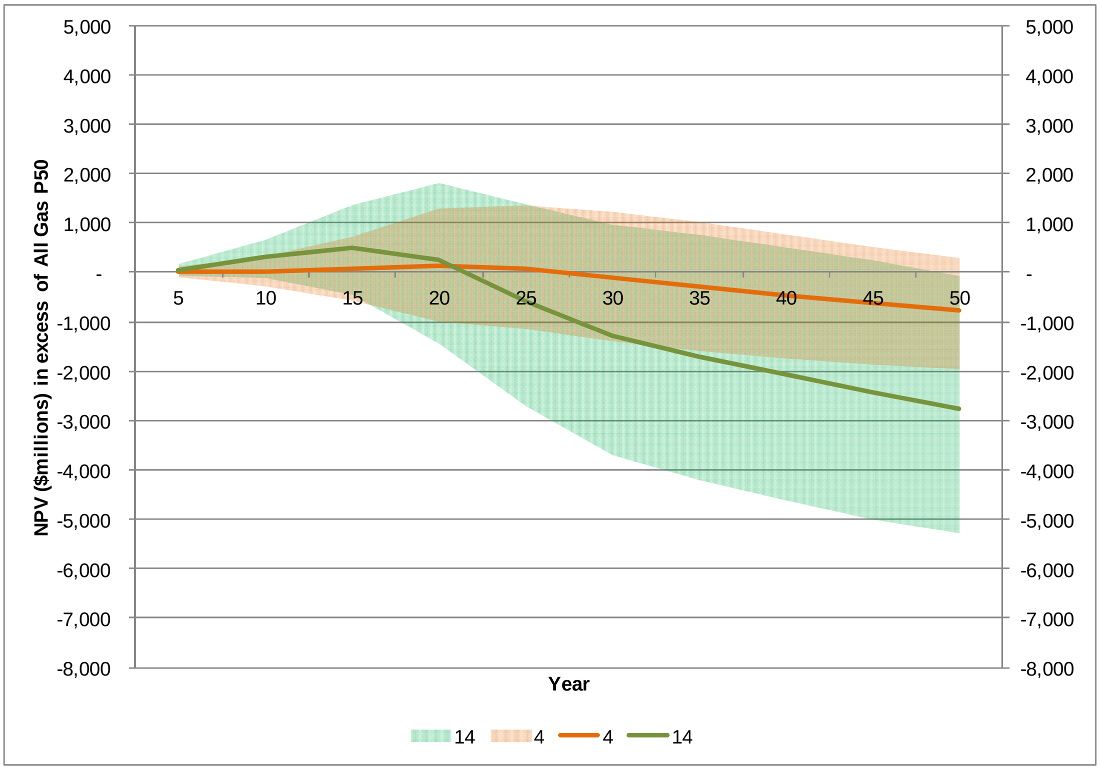
b. Compare the values for Plan 14 (PDP) to Plan 6 (K19/Gas/750MW). This comparison serves as a proxy for the charges that would be applicable for only Conawapa. These payments are assumed to be 100% foregone (Note: it is recognized that Plan 14 includes financial benefits of the WPS investment and sale while Plan 6 does not. Accordingly, the benefits of Plan 14 might be slightly overstated in this example).

c. In each year, revise downwards the level of rates charged to domestic ratepayers dollar-for-dollar with the foregone government charges in that year.

d. Implement the revised charge scheme for 15 years from the in-service date of Conawapa (i.e., this revised sharing only applies from 2025/26 to 2039/40). For all other periods keep government charges at the levels forecast by Hydro.

This above approach is not a perfect representation of implementing such an approach – further consideration would need to be given to balancing rate impacts, reserve levels, etc. However within the bounds of an approach similar to the above, Figure 35 shows the cone graph for impacts on ratepayers.

Figure 35: Plan 4 (K19/Gas/250MW) vs. Plan 14 (PDP) with Government Benefit Sharing Relief at 5.05% Real Discount Rate - NPV of Incremental Domestic Costs as Compared to Plan 1 (All Gas) Expected Value ($ Millions)



As shown in Figure 35 above, this type of approach over a limited number of years (in this case 15 years) can play a substantial role in addressing the risk and benefit sharing disparities between Government and ratepayers. Under this scenario, government revenues are reduced as compared to Plan 14 (PDP); however the revenues remain higher than the government revenues expected in Plan 4 (K19/Gas/250MW) and under the assumption that Plan 14 (PDP) would not proceed without this form of sharing (as it is not in the best interest of ratepayers without this type of sharing, based on present forecasts for energy and economic conditions at this time), there is no lost revenue to the provincial Government in any event.

Other scenarios would need to be assessed as part of decisions regarding whether to proceed with Conawapa.

APPENDIX D

LOAD FORECAST AND APPROACH TO DSM MODELLING

APPENDIX D – LOAD FORECAST AND APPROACH TO DSM MODELLING

This appendix reviews Manitoba Hydro's load forecast approach and methodology as used to form the basis of "need" in the NFAT review. It is organized into the following sections:

1) Historical Load Forecasts; and

2) Load Forecast Growth Rates used in NFAT.

Manitoba Hydro's load forecast methodology is set out in NFAT Chapter 4 and based off Appendix C: 2012 Electric Load Forecast (for the 2012/13 Fiscal year). An updated 2013 Electric Load Forecast is provided as Appendix D to the filing (for the 2013/14 Fiscal year). In assessing the reasonableness of Hydro's load forecast InterGroup was aware that the Board had retained Independent Expert Consultants to specifically review in detail the load forecast, and that other intervenors were expected to take a lead role in this area. For this reason, InterGroup's review focused on a 'reasonableness test' based on (a) assessing the degree of instability in Hydro's past forecasting over a long-term period and (b) insights this can provide to NFAT load forecasts.

Over the past few decades, there has been substantial criticism of Canadian Crown utilities producing overly optimistic load forecasts supporting construction of new baseload plants. While it is important to test whether Manitoba Hydro has exhibited a tendency to over-forecast growth, the evidence in this Appendix suggests this is not the case.

It is important to note that utility load forecasting over the short-to-medium term is a process that can often benefit from advanced analytical techniques. In contrast, load forecasting over the long-term is a very different and highly subjective exercise. The potential compounding effects of such matters as economic growth, immigration, technology change, and relative fuel price levels can have major impacts over the long-term that far exceed the benefits of small incremental and analytical technique improvements. It is also important to recognize that two load forecasts can differ by only a small percentage, but lead to fairly major changes in the forecast date of the need for the next resource when that need date is a decade or more into the future. This is an unavoidable reality of mathematics. It is also a reason why mitigating future risk of insufficiency through early project development is generally a more conservative and safer strategy than delaying development of resources until they are actually needed, which risks supply shortfalls.

Hydro has adopted an approach to the NFAT loads based on the following approaches:

1) Select a single baseline load forecast based largely on fixed growth projections, and use this for almost all NFAT modelling;

2) Treat DSM as a modification of future loads (rather than as a future supply option); and

3) For a select number of cases, review the sensitivity of conclusions to possible futures where the load forecast is considerably higher or lower than expected but still within a reasonable range.

Given the approach Hydro has adopted overall in the NFAT, this load forecasting approach is reasonable. There are two narrow exceptions; however, these are of the nature of incremental improvements or final cross-checks rather than fatal flaws:

1) **Extreme Low Loads:** If the scale of future benefits is materially affected by the level of load, then more extreme sensitivities should be tested to determine if there are threshold outer bounds that may change the basic conclusions. An example of this is seen in analysis done for the 2013 update, where the economic benefits of Plan 14 (PDP) over Plan 4 (K19/Gas/250MW) at REF-REF-REF conditions is reduced from \$329 million to \$196 million, or more than 40% when a lower load forecast is used[1]. As set out below, this low load scenario is still representative of a 0.9% average growth rate[2]. The NFAT review would benefit from additional analysis of the impacts of extreme low load scenarios below this range to see what level would have to be exceeded to change conclusions regarding Plan preferences. It is understood that this analysis may still be forthcoming from Hydro.

2) **Risks Related to High Loads:** There are presently a number of specific potential large new industrial loads for Manitoba that may come online in the future, as well as a wide range of possible future scenarios that could lead to more load additions. While these are not expected as the most likely outcome, it is plausible that this could arise, particularly in the cases of high energy prices affecting the comparable competitiveness of rates in Manitoba versus other jurisdictions over the coming decades[3]. Such high load scenarios could for example, prove to weaken the economics under a future with Plan 1 (All Gas) but show much better support for

[1] In this case representative of 4x DSM. NFAT Figure 12.6 of Chapter 12. However this is also consistent with any future where the loads grow at a slower than expected pace, whether due to DSM or other factors.

[2] Depicted below in Figure 9; this is the average growth rate per year of the 4x DSM scenario for the 2013 Load Forecast, with values from Appendix 4.2.

[3] There is a degree to which industrial rates do matter to location decisions. This is not true for many loads, such as mines and pipelines, which must be located where the resources require. It can be true for other loads such as mineral processing, industrial manufacturing operations, chemicals, etc.

larger options such as Plan 14 (PDP) which provide greater flexibility to meet these load requirements, particularly if they arise relatively quickly.

Hydro's approach to DSM is appropriate for an NFAT review focused on assessing opportunity-based futures. Under these types of scenarios the major decisions that are required in the near-term are about commitments to resources that do not come into service until 2019 to 2026 or later. Decisions regarding the construction of new facilities for that era are required in the next few years. Decisions about the precise level of DSM are not – DSM is more flexible and can be amended over time. For this reason the key assessment pertaining to DSM and the load forecast is confirming that a later decision to pursue an aggressive program of DSM will not undermine decisions to proceed with a plant such as Keeyask, and vice versa. Hydro's filing provides the necessary detail to conclude that DSM, Keeyask, Conawapa and a 250MW or 750MW US transmission line are not generally competing resources, but can instead be complementary.

1.0 HISTORICAL LOAD FORECASTS

InterGroup's primary review focused on compiling data from load forecasts dating back to 1993/94 through the present day, and comparing these forecasts to weather-adjusted actual data and more recent forecasts[4]. The purpose of this review was to:

- Determine if Manitoba Hydro has had reasonable approaches to developing forecasts in years past;
- Assess whether the long-term patterns of loads in Manitoba are highly variable or more stable; and
- Consider how wide a range has been projected in the past in relation to the current NFAT (i.e., is the current filing too narrow in terms of the range of possible outcomes).

Within the reasonable bounds of long-term load forecast expectations, Manitoba Hydro's load forecasts appear to have generally tracked trends in power usage well. Each individual forecast can be off by a certain degree, but the forecasting process has been largely self-correcting over a series of years. The forecasts below have been broken out into timeframes or generations to show the trends of Manitoba Hydro's forecasts.

The below comparison focuses only on energy (not peak) and uses total system load (less station service), rather than load by class. This is necessary as (1) the earlier forecasts did not have breakdowns

[4] Actual Weather Adjusted Net Firm Energy from the following sources: 1993/94 - 2001/02 actual net firm load energy 2002/03 load forecast, 2010/12 GRA, Appendix 55, page 55. 2002/03 - 2011/12 actual net firm energy from 2012/13 load forecast from Appendix C of NFAT Business Case, page 38 (deducting station service on page 36).

for the former Winnipeg Hydro load into classes, and (2) the older forecasts did not separately identify or include station service within the forecast.

It is also important to note that the coloured lines below arise from load forecasts and are before DSM activities. The black lines are actuals, and include the impacts of DSM activities. For this reason even a perfect load forecast would tend to show a higher forecast than actually occurred.

Figure 1: Manitoba Hydro Historical and Forecast Net Firm Energy (GW.h) 1993/94 - 2002/03 Forecasts[5]

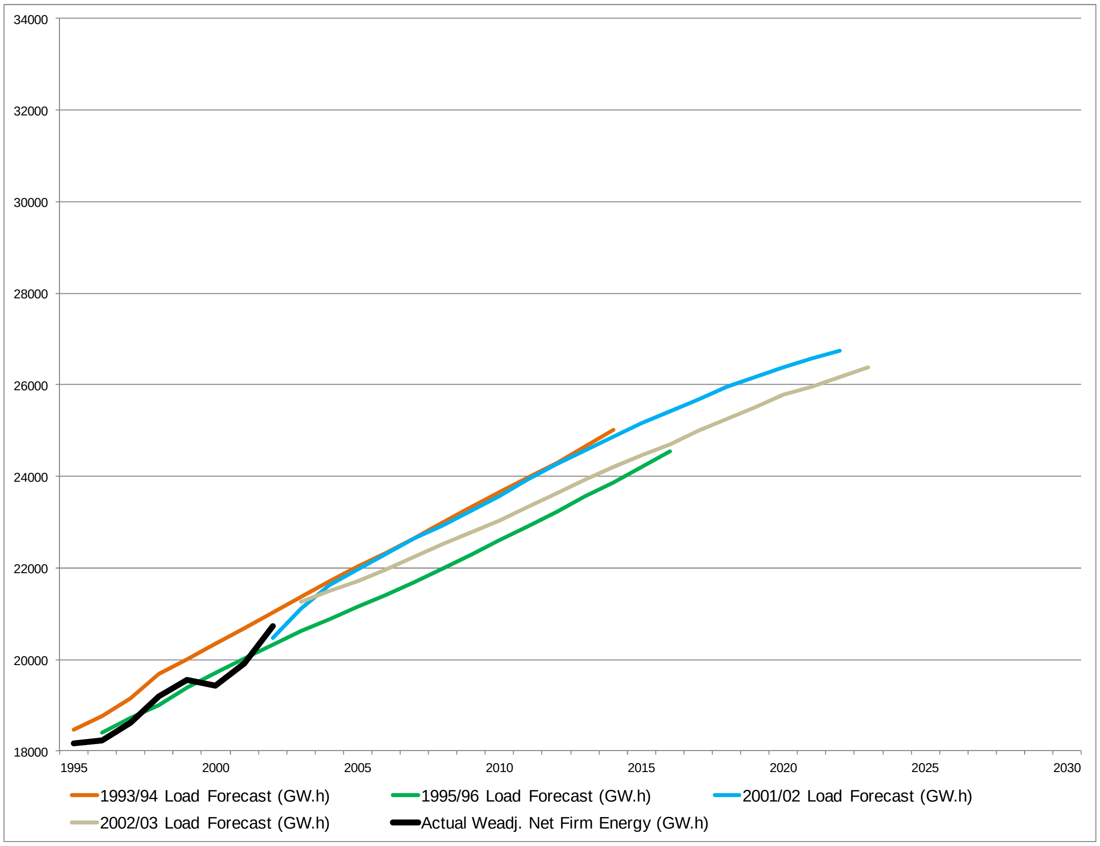


Figure 1 above shows four load forecasts from 1993/94 to 2002/03 as well as actual weather adjusted load data (in black). Over this period actual Manitoba domestic customer load was growing on average 1.85% per year[6]. The forecasts during this period tended to track actual growth well, but over long horizons predicted more modest growth – in the range of 1.11% to 1.6% on average per year depending on the forecast.

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[5] 1993/94 Load Forecast from 1994 Minimum Filing Requirements Volume 1, Appendix III Table 1, page 1. 1995/96 Load Forecast from 1995 Minimum Filing Requirements, Appendix III, Table 1, page 1. 2001/02 Load Forecast from Status Update Filing, Volume II, Appendix 7, Table 1, page 1 (November 2001). 2002/03 Load Forecast from 2010/12 GRA, Appendix 55, Table 1, page 1.

[6] 1993/94 load of 17,913 GW.h to 20,738 GW.h in 2001/02 over eight years.

Figure 2: Manitoba Hydro Historical and Forecast Net Firm Energy (GW.h) 2003/04 to 2005/06 Forecast[7]

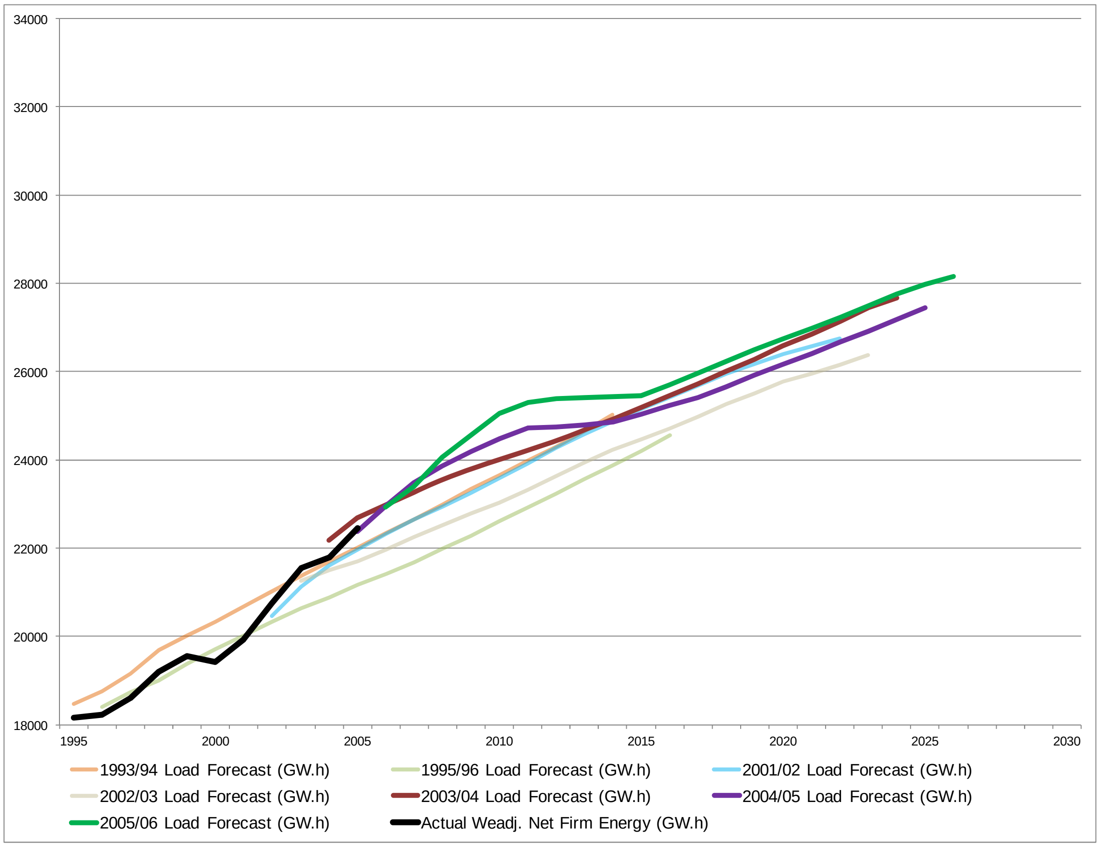


Figure 2 above repeats the data from Figure 1 (in pale colours) and adds three more load forecasts from 2003/04 to 2005/06. During this period actual Manitoba domestic customer load had been growing faster than in years past (on average 2.3% per year)[8]. As a result, Manitoba Hydro's load forecasts over this time period reflected an expectation of some continuation of this higher trend, but a general reversion to slower growth levels over the long-term.

To compare, average growth in the first ten years of these forecasts ranged from 1.13% – 1.18% per year and in the second ten years from 0.91% – 1.05% growth per year. Over the entire 20 year period, forecasts ranged from 1.03% – 1.11% per year.

[7] 2003/04 Load Forecast from 2004 GRA, Volume II, Appendix 6.2, Table 1, page 1. 2004/05 Load Forecast from General Rate Increase as Approved Conditionally in Board Order 101/04, CAC/MSOS/MH I-9(a), table 1, page 1 (February 2005). 2005/06 Load Forecast from 2006/08 GRA, Volume II, Appendix 7.1, Table 1, page 1.

[8] 21,545 GW.h actual load in 2002/03 to 23,082 GW.h in 2005/06 over three years.

Figure 3: Manitoba Hydro Historical and Forecast Net Firm Energy (GW.h) 2006/07 to 2008/09 Forecast[9]

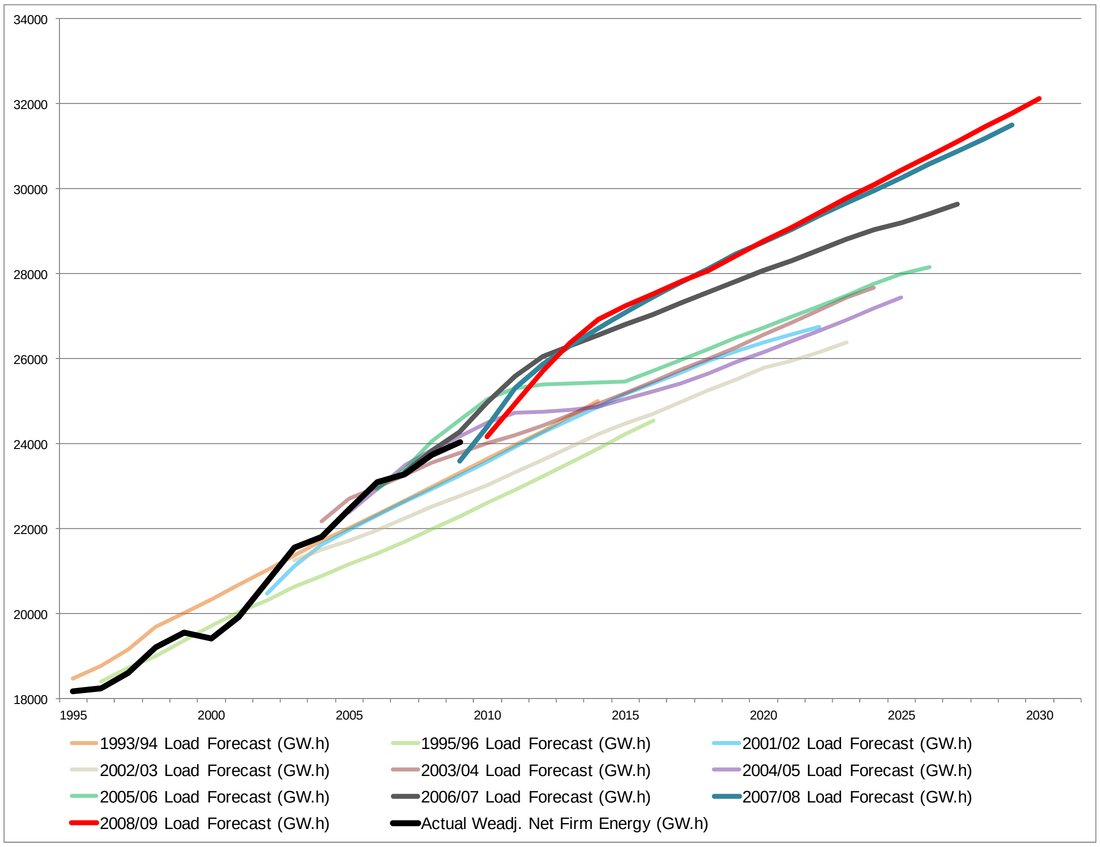


Figure 3 shows that starting in 2006/07 to 2008/09 actual domestic load had higher growth rates than in the past, as shown in Figure 2. Actual average growth over the ten year period (from 1996 - 2006) averaged 2.39% per year.

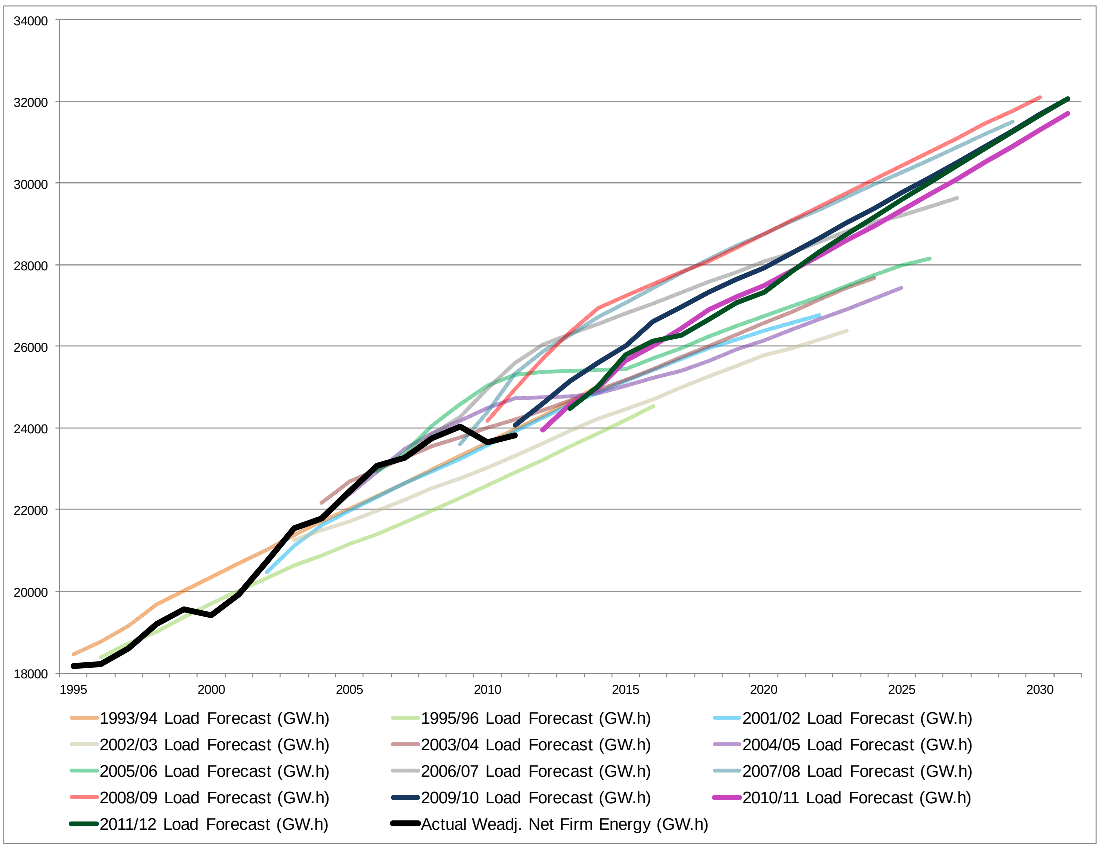
Manitoba Hydro's forecast over this time frame started to reflect an expectation of very high near-term growth rates for the initial period, followed by reversion to lower rates. It is also important to note that during this period Hydro had begun to discuss with customers that future growth may be subject to much higher charges than existing load (the then-proposed Energy Intensive Industrial Rate, or EIIR). As a result, there is a possibility customers were incented to provide Hydro somewhat higher load forecasts to attempt to protect what were then still relatively speculative near-term load increases from the EIIR charges (i.e., become part of the "grandfathered" base load). This may be driving part of the near-term increases projected.

Over the long-term, Hydro did not project the high growth to continue, and predicted only 1.2% - 1.46% annual average growth.

[9] 2006/07 Load Forecast from 2008/09 GRA, Appendix 7.1, Table 1 on page 1. 2007/08 Load Forecast from 2008/09 GRA, Appendix 25, Table 1 on page 1. 2008/09 Load Forecast from Energy Intensive Industrial Rate Application, Appendix 2, Table 1 on page 6.

During this time period, the effect of the high early-year growth advanced the date when new resources would be required. For example, looking at the 26,000 GW.h load level, the earlier forecasts would have indicated that this scale of generation would not be required until somewhere between 2016 and 2020. With the growth of the early years, during this period, Hydro would have started to plan for this level of generation for 2011 or 2012. While this load growth did not come to pass (see below), it serves to illustrate how sensitive a resources "need" date is even within load forecasts that do not show severe changes in long-term growth rate (i.e., in this era the long-term rates only increased from the 1.03%-1.11% range into the 1.20%-1.46% range, an increase of only 0.17%- 0.35%).

Figure 4: Manitoba Hydro Historical and Forecast Net Firm Energy (GW.h) 2009/10 to 2011/12 Forecast[10]

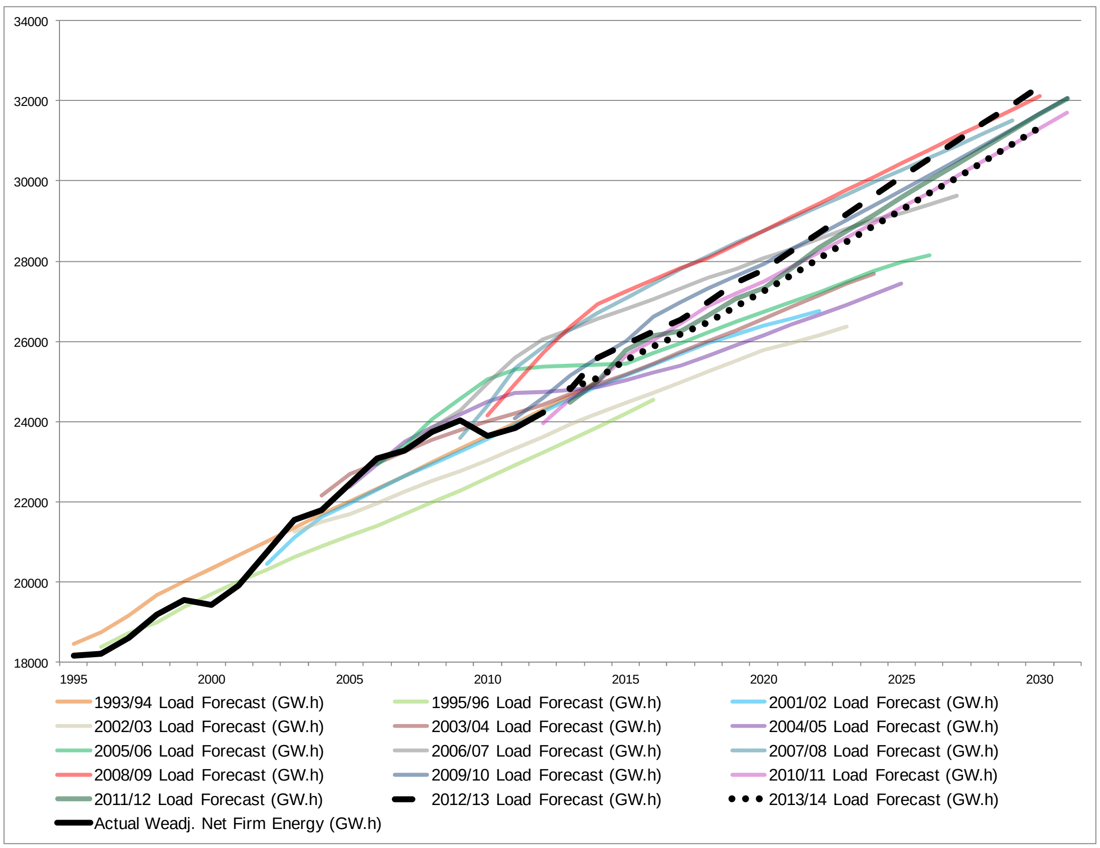


The final presentation of load forecasts prior to the NFAT is in Figure 4 and shows actual load dropping off fairly substantially in 2009/10 as a result of economic conditions and plant closures.

[10] 2006/07 Load Forecast from 2008/09 GRA, Appendix 7.1, Table 1, page 1. 2007/08 Load Forecast from 2008/09 GRA, Appendix 35, Table 1, page 1. 2008/09 Load Forecast from EIIR hearing, Appendix 2, Table 1, page 1. 2009/10 Load Forecast from 2010/12 GRA, Appendix 7.1, Table 1, page 6. 2010/11 Load Forecast from 2010/12 GRA, Appendix 62, Table 1, page 8. 2011/12 Load Forecast from 2012/14 GRA, Appendix 8.1, Table 25, page 43.

As a result, the forecasts over this period are significantly lower than Manitoba Hydro's forecasts from the EIIR era. Despite this lower absolute value (due to the recession) the average long-term growth rates are among the highest ever produced by Hydro, ranging from increases of 1.44% – 1.50%. However, the forecasts are also more consistent, compared to the EIIR era when Hydro appears to have attempted to balance expected high early load growth with lower long-term load growth. Overall the long-term load trends used by Hydro (other than the 2006-2008 period) tend to fall into a relatively tight range, and track reasonably well with actual results, given the degree of traditional uncertainty and subjectivity in forecasting.

Figure 5: Manitoba Hydro Historical and Forecast Net Firm Energy (GW.h) 2012/13 and 2013/14 Forecasts[11]



The NFAT load forecasts are included in Figure 5 as black dashed (2012) or dotted lines (2013). By this time, actual domestic sales over the 17 year period from 1994/95 to 2011/12 (including the effects of DSM) grew on average 1.71% per year. The two load forecasts from the NFAT filing, 2012/13 and 2013/14 continue on the same general trend as the previous years. The 2012/13 load forecast is somewhat higher in the later years than the 2013 forecast (average annual growth of 1.56% per year)

[11] 2012/13 Load Forecast from Appendix C of NFAT Business Case as gross firm less station service on page 37 and 38). 2013/14 Load Forecast from NFAT Filing, Appendix D, as gross firm less station service on pages 35 and 37.

while the 2013/14 load forecast dropped this rate, averaging 1.36% growth per year over the twenty year forecast.

Figure 6: Manitoba Hydro Historical and Forecast Net Firm Energy (GW.h) 10th and 90th Percentile Forecasts (2012/13 Load Forecast)[12]

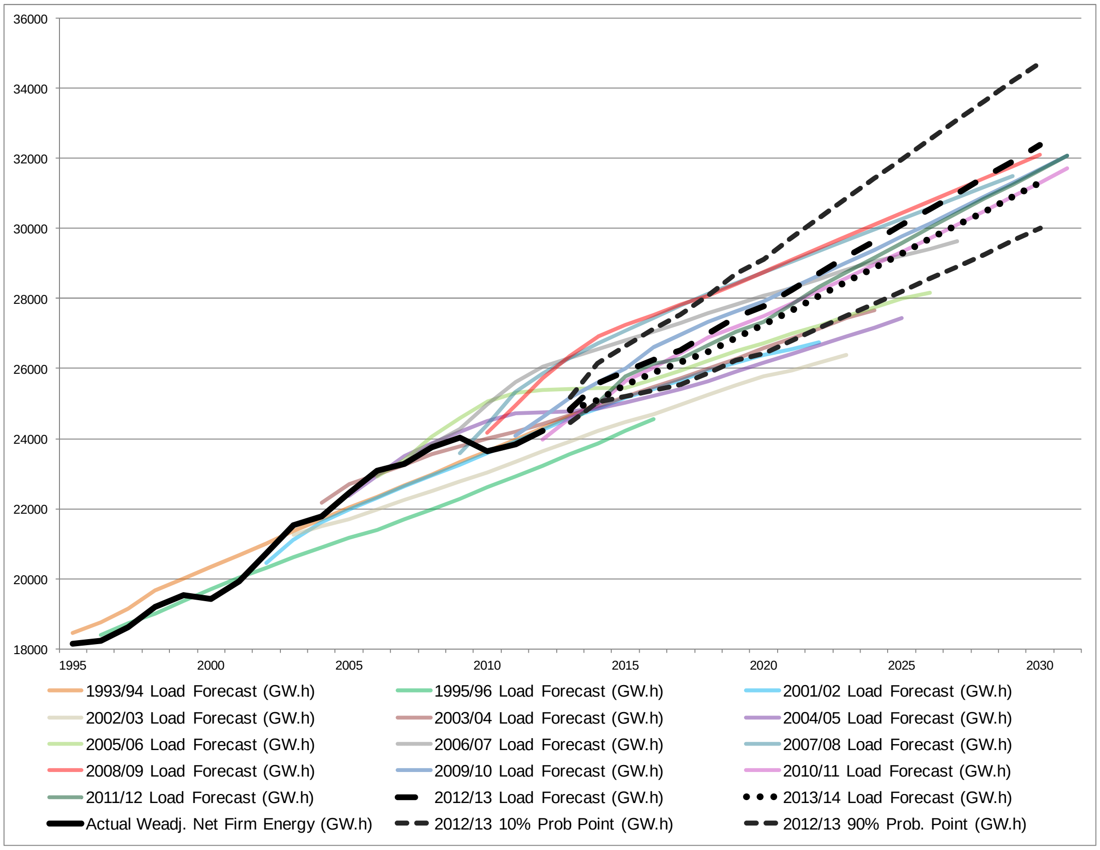


Figure 6 above shows the addition of Manitoba Hydro's sensitivity load forecasts. This includes the 10th and 90th percentiles. This figure serves to illustrate the wide range of sensitivities that arise when these load cases are tested against the NFAT Plans and why they provide what is generally a reasonable outer band of expected experience.

[12] 2012/13 Load Forecast from Appendix C of NFAT Filing - 10th and 90th percentiles from page 46 and 47 (less station service on page 37).

Figure 7: Manitoba Hydro Historical and Forecast Net Firm Energy (GW.h) Four Times DSM Forecast (2013/14 Load Forecast)[13]

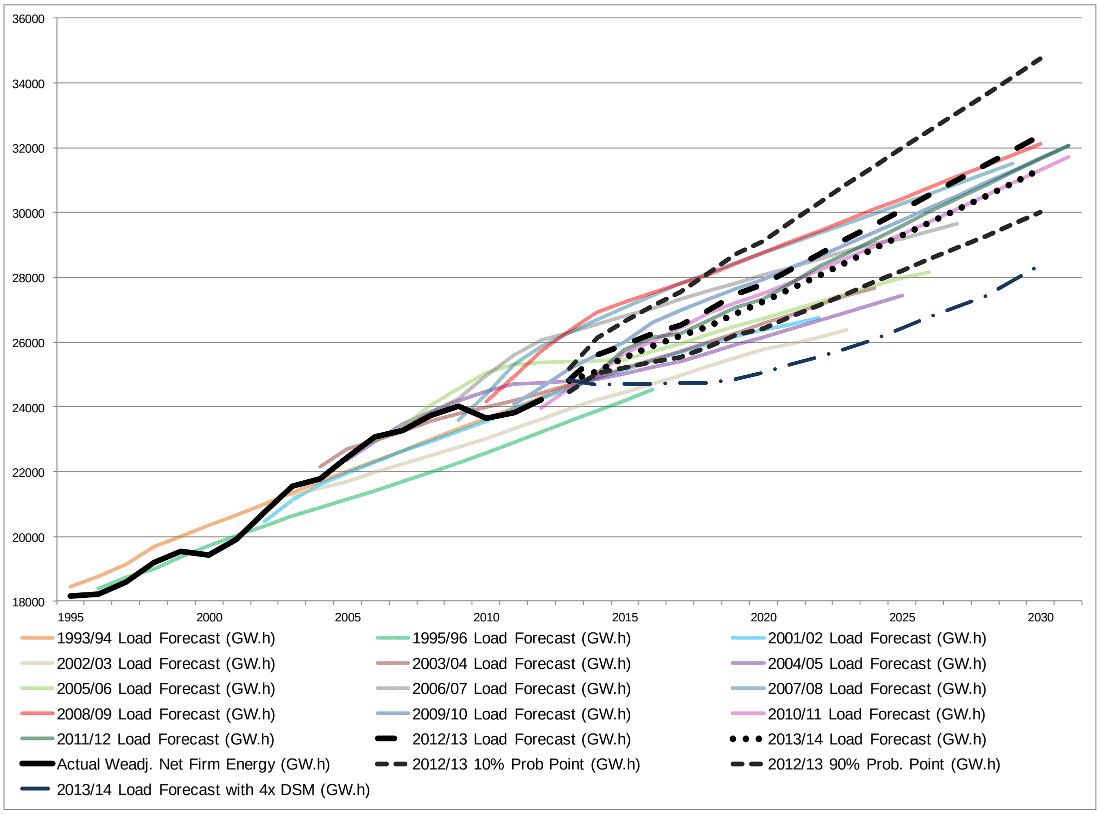
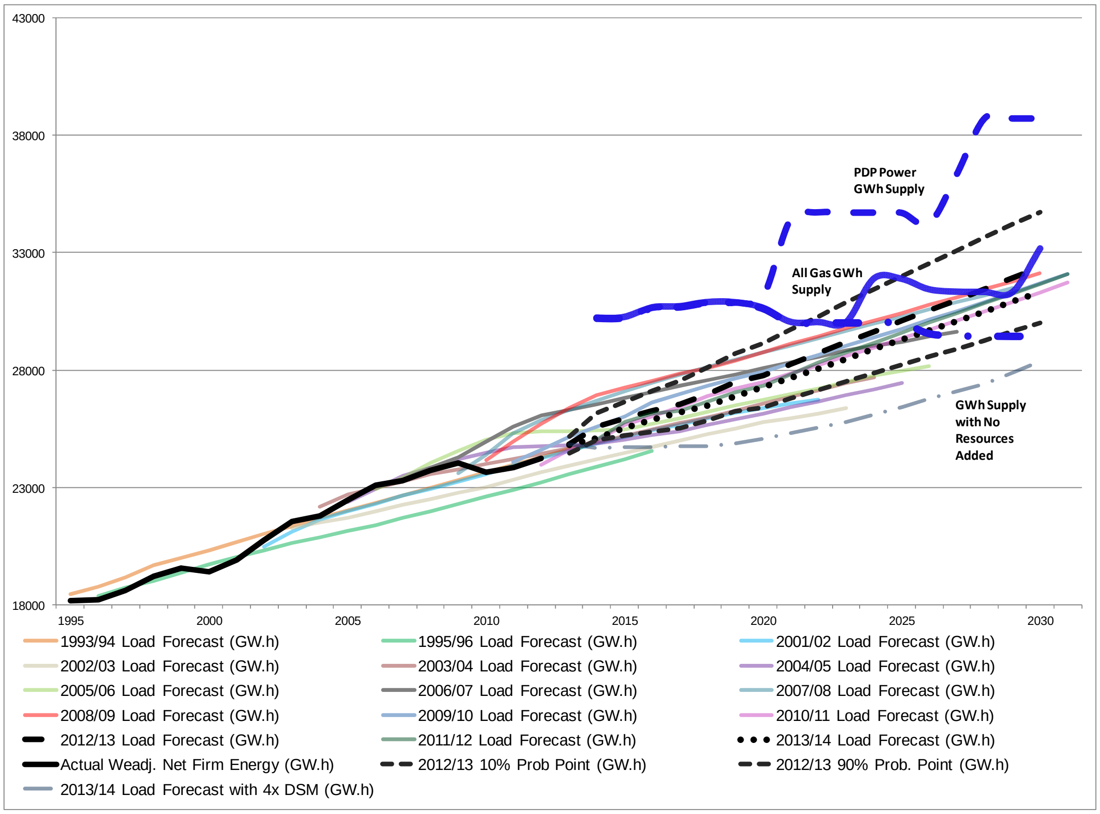


Figure 7 adds the final scenario modelled by Hydro – the 4x DSM scenario from the 2013/14 Load Forecast to the load chart (the lowest line illustrated). Manitoba Hydro provided some limited analysis of the NFAT projects assuming this future load scenario, and it is InterGroup's understanding that further information on these scenarios is forthcoming. The above image serves to illustrate the basis of InterGroup's conclusion that the load ranges tested by Hydro, including the potential future effects of DSM, are likely sufficiently broad enough to fulfill the NFAT evidentiary needs regarding low growth futures.

[13] Net Firm Load Forecast with 4X DSM from NFAT Filing, Appendix 4.2, Base Load Forecast less 4x DSM on pages 150 and 152 (less station service from page 35).

**Figure 8: Manitoba Hydro Historical and Forecast Net Firm Energy (GW.h)
No New Resources, All Gas and PDP Added Energy[14]**



For reference, the above Figure 8 compares the available dependable supply options available for serving domestic load (generation less export commitments – dark blue lines): (a) if no new resources are built, (b) under Plan 1 (All Gas), and (c) under Plan 14 (PDP). As illustrated by Figure 8, both Plan 1 and Plan 14 provide low load scenarios with secure energy supplies, but Plan 14 (PDP) is best able to deal with possible high load scenarios. Within the range of load forecasts shown in Figure 8, it is possible that gas resources may be required from 2-6 years sooner than forecast in Plan 1 (All Gas). While this has not been highlighted by Hydro in the NFAT, one benefit of the larger scale plans is this protection and flexibility for future load uncertainty.

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[14] NFAT Business Case, Appendix 4.2: Supply and Demand Tables, No New Resources from pages 120 and 122. All gas plan from pages 140 and 142. PDP from pages 124 and 126.

2.0 LOAD FORECAST GROWTH RATES

Figure 9 shows the average annual growth rate used for each Load Forecast in the forecast net firm sales, as compared to the actual weather-adjusted growth (which includes DSM).

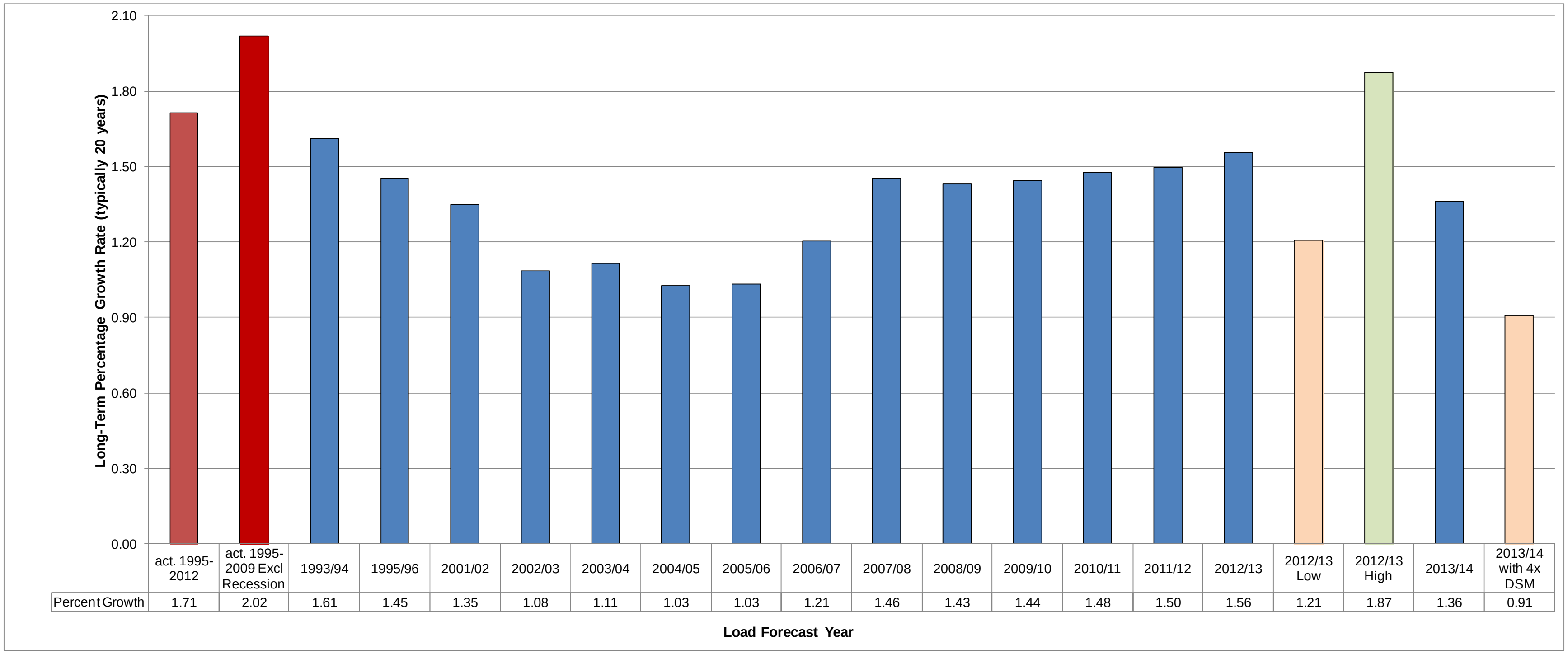
The red column show the actual average annual growth rates over (a) all years, and (b) all years except the recent recessionary period (i.e. actual growth rate up until 2009), which some may conclude is an atypical event. Note that over long horizons, atypical events are to be expected, so the best representation of past experience in the first column shown, but it is also important to note that prior to 2009 this load drop was not anticipated and Hydro had been preparing load forecasts on the basis of recent actual load growth at the level shown in the second column. As compared to the growth rates projected by Hydro (the blue columns) this serves to illustrate the basis for the InterGroup conclusion that Hydro has not traditionally been overly optimistic in its assumed growth rates.

The blue columns show the long-term average growth rates used in each of the respective load forecasts used in Section 1 above.

The growth assumed for the 2012/13 Load Forecast (the forecast used in the NFAT) is towards the right hand side of the figure. While it is the second highest of any load forecast analyzed, it is below the long-term actual growth rates. Also note that the pink columns show the range for low load (10th percentile) and green shows high load (90th percentile) which illustrate a wide band. Further it is important to note that the NFAT also includes (but is not fully updated for) the growth rates shown in the final blue bar – the 2013 load forecast. This forecast is well within the typical forecasts prepared, and well below the long-term average actually experienced.

The final pink column is the 2013/14 Load Forecast with 4x DSM sensitivity. This represents a reasonable low case to be tested as a sensitivity. As noted above however, as an outer limit case, the NFAT should ideally be exposed to further low load sensitivity modelling consideration to ensure, if this extreme future arises, the basic conclusions in the NFAT are not altered or undermined.

Figure 9: Manitoba Hydro Load Forecast - Long Term Growth Rate Assumed[15]



[15] Calculated as average annual growth of net firm load in GW.h across 20 year load forecast from data referenced and shown in previous figures.