Manitoba Hydro Needs For and Alternatives To Review

MIPUG FINAL ARGUMENT
WRITTEN SUBMISSION
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PREFACE

This written submission has been prepared to assist the Board and other parties in navigating the evidentiary record of the Needs For and Alternatives To (NFAT) Review to date and sets out MIPUG's position on Manitoba Hydro's Preferred Development Plan (PDP) and potential alternatives. The written submission includes the following:

- As a point of reference, this submission provides a copy of the transcript pages (pages 40 – 48) of MIPUG's opening comments on March 3, 2014 as Attachment 1. This sets out the key issues to be addressed in the hearing, from MIPUG's perspective, and provides a road map to the MIPUG case throughout the proceeding.

- The remainder of the submission is organized by general issue or question as follows:

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MIPUG recognizes many of these issues are interrelated and cannot be fully appreciated in complete isolation. Therefore this written submission is intended to supplement, but not substitute for, MIPUG's oral argument. MIPUG appreciates the opportunity to prepare and submit these written comments.

To the extent that MIPUG does not expressly reply to an issue raised or position taken by another party to the proceeding, MIPUG should not be taken to agree with or consent to the other party's position.

INTRODUCTION

MIPUG is an association of major industrial customers operating in Manitoba mostly belonging to the GSL >100kV and GSL 30-100 kV classes. These customers work together on issues of common concern related to electricity supply and rates in Manitoba. To that end, MIPUG has 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 the Hydro's Major Capital Projects in 1990. MIPUG members currently include:

- Amsted Rail - Griffin Wheel Company (Winnipeg);
- Canexus (Brandon);
- Enbridge Pipelines Inc. (Southern Manitoba);
- ERCO Worldwide (Virden);
- Gerdau Long Steel North America – Manitoba Mill (Selkirk);

- HudBay Minerals Inc. (Flin Flon);
- Koch Fertilizer Canada ULC (Brandon);
- Tolko Industries Ltd. (The Pas);
- TransCanada Keystone Pipeline (Southern Manitoba); and
- Vale (Thompson).

Members' concerns are reflective of the size of their investments in Manitoba, the long term view essential for such investments, and the requirement for continued large-scale purchases from Hydro. Members' concerns also reflect competitive market pressures from selling Manitoba industrial products to external markets, and the need to secure the lowest reasonable costs for power and other production inputs, to offset disadvantages from operating in Manitoba, such as transportation. Mr. Turner, Interim Chair for MIPUG summarized MIPUG's concerns and the current economic environment during his presentation to the Board on April 16, 2014:

> MR. BILL TURNER: The association's key concerns related to electricity costs are stability and predictability of rates, ongoing transparent regulation of Manitoba Hydro's rates and major capital spending, and ensuring rates for all customer classes reflect the fair cost to serve the class.
>
> In past presentations before the PUB, we've explained that the cost of power is very important to the operations and growth of industry. MIPUG members compete in a global marketplace, and attractive cost-based electricity rates allow industries to remain competitive in Manitoba by offsetting some of the geographic, climate, and other disadvantages faced by industry in this province, including distance to market.
>
> The decrease in the cost of power in the USA produced by natural gas is making it more difficult for some major Canadian and Manitoban companies to be as competitive in the export of finished goods. Also, many MIPUG members compete globally, where the cost structures are far more difficult to match.
>
> Competition for the MIPUG members is internal to each company as well as external. Most MIPUG members have sister plants in other jurisdictions that compete for capital investment. Businesses make location and capital investment decisions based on cost and predictability.
>
> Industry takes a long-term view in making these decisions. It is not just today's rates, but also tomorrow's rates, that are of interest. Once you

have invested many millions in a plant and its staff, exposure to electricity pricing changes is high (Tr: 7201-7202).

..

MR. BILL TURNER: … [W]ith the changes in Manitoba and the natural gas price changes affecting competitive jurisdictions, Manitoba's position with respect to power costs has changed. For many MIPUG members, Manitoba has been among the lowest-cost jurisdictions for power in the past. This is not true today (Tr: 7207).

MIPUG SUMMARY OF RECOMMENDATIONS

The following is a summary of recommendations from Manitoba Industrial Power Users Group (MIPUG) on the Manitoba Hydro Needs For and Alternatives To (NFAT) Review. These recommendations are discussed further in the Issue Topics following.

MIPUG Interest

MIPUG recognizes that proceeding is a rarity in Manitoba – it only the second full Public Utilities Board (PUB) review of Hydro's Resource Plan in over 25 years. It is also extraordinary in its scope and scale. MIPUG welcomed the Order In Council (OIC) that established this hearing, given the scale of commitments being made which will affect all domestic customer classes for years to come. As Mr. Hacault noted at the May 16, 2013 Pre-Hearing Conference:

> MIPUG members have been among the parties recommending that this review occur, and we're very pleased that it's the PUB that is going to be conducting this review as a result of its unique expertise and understanding the public interest as it relates to the power system and impact on the rates.
>
> …
>
> Hydro's proposals need to be reviewed based on, firstly, least-cost supply for Manitoba domestic customers, and, secondly, the benefits expected to arise to domestic ratepayers who will inherently carry the financial risks for Hydro's developments (Tr: Pre-Hearing Conference 2013-05-16:173).

And more briefly, in introducing MIPUG's position that the Board should recommend those capital planning elements which are shown to be in the best interest of Hydro's domestic customers throughout the planning period in light of all relevant benefits, costs and risks:

> The simple point is that rates do matter (Tr: 41).

Mr. Turner, Chair of MIPUG highlighted the MIPUG interest in this proceeding:

> When it comes to rates, both Hydro developments and transmission connections to other jurisdiction typically fit with industry's needs. This is because industry has to be concerned about the long-term rates and because it is important that power rates are stable. Both of these things are critical to companies that collectively invest billions in plants in Manitoba.

> Industry also cares about reliability. And hydro provinces with interconnections have typically proven to perform well in this measure.
>
> Also important to industry is that sufficient power is available for growth and expansions. When Manitoba Hydro advances the in-service date of its new plants, there's more room to meet unexpected load growth by all industries.
>
> For all these reasons Manitoba Hydro has been a good partner for industry, and future hydro developments should be something industry supports (Tr: 7205).

However, Mr. Turner also underlined the challenge inherent in Hydro’s proposals when he noted that under Hydro’s initial numbers, industry would end up paying an approximate sum of $400 million more over the next twenty (20) years for the Preferred Development Plan (PDP or Plan 14) rather than viable alternatives, and only in the later decades of the PDP would rate benefits may begin to arise (and with risks this impact could be higher and the benefits pushed out in time). Mr. Turner explained:

> This is $400 million that will not be available to Manitoba companies to invest in expansion, employees, community support, and other actions that may help with competitiveness.
>
> We were informed new numbers may show the impacts being even larger. At the same time, we were informed the provincial government will significantly increase its recoveries from Hydro with this plan. This, in fact, underlines the NFAT challenge.
>
> In principle, MIPUG is among the first to support hydro development in Manitoba. However, MIPUG will have to undertake a careful review of the financial evidence in this hearing before it will be able to make a decision as to whether the full PDP is in the best interests of ratepayers (Tr: 7207-7208).

Mr. Turner also noted that rates matter not just to the operators of industrial companies, but to all of the stakeholders involved. He specifically noted that it is not just whether Manitoba’s rates are viewed as low compared to other places – each increase or decrease in rates has a direct impact on Manitoba’s economy, regardless as to what rates are doing in other locations. Using the example of mining companies, he noted:

> There are some valuable minerals in all rock; ore is that material that can be profitably mined to create exportable products, jobs, and industry.

> This is dependent on international competition, product demand, and the price of the product, but also on the cost to mine and process the material. Electricity costs are a key element of determining what is ore and what is rock. All things being equal, lower prices for power means more ore, more jobs, and more activity (Tr: 7202-7203).

The Terms of Reference for the NFAT provided to the PUB specifically require that the Board take into consideration item 2(j): "If the Plan has been justified to provide the highest level of overall socio-economic benefit to Manitobans, and is justified to be the preferable long-term electricity development option for Manitoba when compared to alternatives"[1]. This must include not only the socio-economic benefit and cost of pursuing Hydro's plan and its direct effects, but also other effects in the economy arising due to rate impacts.

MIPUG is aware that large scale hydro development will produce significant economic benefits for the province of Manitoba and its citizens in the form of construction jobs, worker incomes, income taxes, fees charged to Hydro, and also investment opportunities for First Nations. Hydro has provided extensive evidence on these matters, supplemented by the detailed work of the Independent Expert Consultant (IEC) TyPlan[2] to assess these claims. MIPUG supports securing each of these benefits, so long as they are achieved in concert with benefits for ratepayers, who ultimately bear the financial risks for the projects.

At the same time, the Board has not been presented with a robust record on the quantitative socio-economic implications of the rate pressures expected to be required to finance the full PDP, particularly over the first 20 years. Messrs Turner of MIPUG, and Forsyth and Tobin of Gerdau Long Steel North America provided the Board qualitative information on these matters. Further, TyPlan was similarly charged with this task as part of their overall scope of work, item 2, as follows[3]:

> 2. Consider the economic displacement impacts and effects on consumer spending to the extent consumers will face increased electricity rates as a result of the Preferred Development Plan.

[1] Exhibit PUB-2, Terms of Reference – Needs For and Alternatives To (NFAT) Review as provided by the Province of Manitoba to the Manitoba Public Utilities Board on April 25, 2013, page 3 of 8.

[2] Reviewed extensively throughout Exhibit TyP-1, The Needs For and Alternatives To Manitoba Hydro's Preferred Development Plan: Independent Review of Socio-Benefits Final Report, Prepared for Public Utilities Board, Prepared by TyPlan, January 2014.

[3] Exhibit TyP-2, Scope of Work for TyPlan in the NFAT Review, Last Updated September 20, 2013, page 2.

However, their completion of this task in regard to the implications of rate changes for industry, employment, economic development and competitiveness was incomplete. In regard to fulfillment of this scope of work, TyPlan noted:

> Mr. Antoine Hacault: … in your report at the beginning, when you discuss the various matters that were in the scope of your review, one (1) of the things that you mention was a sectorial analysis of the rate impacts. How did you understand that instruction? Was it limited to the residential sector, or did it go further than that?
>
> …
>
> … as I read your report, sir, your sectors were limited to the residential sector, correct?
>
> MR. RUSSELL TYSON: Yes, it was.
>
> …
>
> MR. ANTOINE HACAULT: Okay. So I guess, unfortunately, we don't have your views of the potential impacts, whether they would be positive or negative, on the industrial sector, part of which is represented by Manitoba Power Industrial Users Group, correct?
>
> MR. RUSSELL TYSON: That would be correct (Tr: 7089-7090).

The work of one of the other IECs, Morrison Park Advisors, further highlighted this gap:

> MR. ANTOINE HACAULT: … And the one (1) thing you didn't study is, I gather, from - - or didn't comment on in your report, sir, if I can refer back to the -- the geology example that one of the presenters made, the one (1) thing you didn't study is if rates go up, how many jobs are we affecting and how much ore will -- rock will not be turned to ore?
>
> MR. PELINO COLAIACOVO: And as we said -- as I said in -- in my -- early in my presentation yesterday, there is an economic impact to rising rates, and -- and there's a multiplier impact, economically, that should be taken into account. And we are not competent to do that analysis. There are others who can undertake that kind of analysis.
>
> Given that different plans imply different rate patterns over time, it might be useful for an expert to look at those rate patterns and try and calculate what the economic impact of the difference in the rising rate patterns would be (Tr: 7476-7477).

Hydro's evidence on this matter appears to be fully contained in brief exchange between Mr. Hacault and Dr. Shaffer, who noted that under certain circumstances, Hydro acknowledges that higher rates to industry "could curtail operations" (while also indicating it may only serve to change profit levels, without any comment about the implications of expected profit levels on competitiveness and ongoing investment) (Tr: 3968).

In short, the evidence before this Board on the economic benefits, particularly to government, of Hydro's PDP (and more generally the broad pathway that encompasses the PDP, including Plans 5 (K19/Gas/750MW/WPS Sale), 6 (K19/Gas/750MW) and 12 (K19/C31/750MW)) is both extensive and overwhelmingly positive. The information on economic impacts of this pathway and its associated higher rate pressures, particularly on companies and industry, their employees, and the regions of the province in which they operate, is unfortunately far less complete. It is clear, however, that unless measures are taken to neutralize upwards pressures on rates due to the PDP in the coming decades (and to offset attendant risks); these impacts are real, adverse, and likely to be significant.

MIPUG's Final Argument focuses on the central issues of concern to this hearing in light of the requirements set out in the PUB's Terms of Reference. No attempt is made to fully summarize or duplicate the extensive material set out in the presentations of Messrs Turner, Forsyth and Tobin, or in Mr. Bowman's expert testimony or in the key Manitoba Hydro Exhibit #104 or (also known as "MH-104") (including subparts), which updates the economic and financial analysis information for different levels of Demand Side Management (DSM), capital costs of Keeyask and Conawapa, removal of common cost factors (economic analysis only) and potential scenarios including an addition to load due to pipeline expansions.

Issues to be Addressed

The hearing record is extensive, and the range of matters that the PUB has been invited to comment on is wide-ranging. As noted in Mr. Hacault's opening comments:

> …MIPUG suggests a primary focus in two (2) areas. This is taken from the PUB terms of reference.
>
> But firstly, focus on ratepayers' rates and risks. The hearing ultimately ends with a report to the Minister who will make final decisions. If I'm not mistaken, the Minister has many other inputs being provided from other

> departments and consultation processes. For example, I expect that he's dealing with conservation, economic development, Aboriginal affairs.
>
> We say that the unique wisdom which this Board brings is a good understanding of rates and ratepayers. We hope that this perspective is central to the Board's review and report.
>
> Secondly, focus on the decisions that must be made now. Many of the issues that are going to be discussed are matters that cannot be reversed. Primarily, this includes whether to take up export agreements with Minnesota Power and others, which also requires whether to put a shovel in the ground on Keeyask, and whether to build a US line and, if so, at 250 megawatts or 750 megawatts. These are key decisions that we must address.
>
> Many other issues are informative, but do not, in our respectful submission, require major decisions today. They require decisions that can be altered as time goes on, for example, matters such as what level of DSM to target, whether to be more aggressive and aggressively monitor and pursue more wind generation, or whether to continue to spend to protect the Conawapa option.
>
> These last examples that I've given are no means an ex -- exhaustive illustration, but we say that those are not critical decisions that need to be made today, and we urge the Board to make sure it gets the large and irreversible questions clearly explored and decided correctly. Other topics can always be adjusted as time goes on (Tr: 44-45).

Further:

> At its core, we submit that the case is relatively simple. MIPUG has framed this as two (2) major questions: Is Manitoba better off with a need-based approach, sticking to its knitting, avoiding debt and commitments as long as possible, letting the current uncertain market climate settle out before committing to future plans; or is Manitoba better off pursuing current opportunities?
>
> If the focus is on pursuing opportunities as opposed to need, the question is asked. Which plan is the best? (Tr: 46)

Summary of Conclusions and Recommendations

MIPUG submits that the evidence has indicated a broadly based consensus that the PDP and all reasonable alternatives reflect trade-offs on the level of future rates. No plan dominates across all time frames and scenarios. On balance, the following conclusions are supported by the evidence:

1) **Challenging Decisions:** The current hearing situation is challenging, but is made extraordinarily difficult by four facts:

   i. The presence of significant sunk costs of over $1.4 billion. This fact skews the analysis of Keeyask in particular. It makes all non-Keeyask plans bear an extraordinary burden of writing off these costs, and makes plans with Keeyask have the economic advantage of a significant head start.

   ii. The 250 MW transmission line option has been effectively dropped by Hydro. As a result, the only remaining option to secure added US access is the far more expensive 750 MW option.

   iii. A lack of broad resource planning or policy decisions being reviewed by the PUB in advance of a specific project proposal being advanced. In many other jurisdictions such a “resource plan” review will often occur focused on broad directions and more general information prior to a “project specific” review to decide on a precise course of action. This did not occur prior to Keeyask being brought forward as a proposed project and prior to the substantial spending to date on the project.

   iv. The high rate impacts that ratepayers are already bearing for Bipole III, a costly project that has no associated revenue benefits. This means that any PDP rate pressures on customers occur concurrently with already significant increases (by historical standards).

2) **Need-based Plan Remains Credible:** A Need-based Plan focused on minimizing capital investment, pursuing economic DSM, and eventually, when needed for domestic load, building one or more gas units before revisiting new hydro (e.g., one gas unit in 2024, then Keeyask about 2031 or later)[4] is a credible option that can minimize capital spending commitments and rates for many years[5]. No witnesses indicated that this planning approach was unworkable or would fail to meet reasonable utility standards.

[4] Per Exhibit MH-192.

[5] Under all 3 rate methodologies provided by Hydro in Ex. MH-104-12-6, Plan 1 (All Gas) had the lowest cumulative rate impacts to 2031/32, and this assumes all Keeyask costs would be written off. In practice,

3) **Keeyask 2019 with the 750 MW Line Could be Preferred, but needs Revised Benefit Sharing to Achieve Fairness:** Plans that involve advancing Keeyask to 2019 are not needed[6]. As compared to a Need-Based plan, the Keeyask/750 MW plans (known as Plans 5 & 6) without Conawapa hold out a prospect that these two projects *may* turn out to be a good opportunity for ratepayers over the very long-term[7]. This plan also brings significant intangible benefits associated with added cross-border transmission. This decision however comes at a significant cost of higher rates for decades[8] and risks associated with high debt levels, unless significant mitigation measures are pursued:

   i. One necessary mitigation is that Hydro should adopt lower debt:equity and interest coverage targets for at least the next 20 years. This approach would allow rates to be held to a similar level as the All Gas plan[9] (although as a small offset it could somewhat exacerbate the issue of debt levels). The forecast retained earnings levels would still permit Hydro to absorb the impacts of severe adverse events such as a repeat of the worst drought on record[10].

   ii. An added level of mitigation involves a rebalancing of benefits with the provincial government. During the period when customers face upward pressure on rates and added risks due to this plan, the provincial government sees significant and ongoing added recoveries compared to the need-based plans (with benefits already occurring today, such as from the capital taxes on the $1 billion plus spent on Keeyask and Conawapa) regardless of the economic conditions that arise in the future, including drought conditions. Under the current approach, any financial risks as a result of this plan are to be paid for by ratepayers. The

particularly if Keeyask is the next plant for resumed planning as soon as the mid-2020s, such extreme write-offs would not likely be necessary.

[6] See the tests for Need, as set out in the response to MIPUG/MH-I-1.

[7] Cumulative rate increases to 2061/62 under the "Main Submission" rate methodology shows increases of 126-125% for Plan 5/6 (K19/750MW) versus 161% for Plan 1 (All Gas).

[8] Cumulative rate increases to 2031/32 under the "Main Submission" rate methodology shows increases of 94-95% for Plan 5/6 (K19/750MW) versus 82% for Plan 1 (All Gas).

[9] Cumulative rate increases to 2031/32 under the two alternative rate methodologies shows increases of 53-57% for Plan 5/6 (K19/750MW) versus 51-54% for Plan 1 (All Gas).

[10] Retained earnings levels range from $3.5 billion to $4.7 billion. Drought risk, under the reference scenario, never exceeds $2.2 billion under these plans, per MIPUG Ex. 9-4, pg 2-11.

provincial recoveries include both benefits for debt guarantee fees[11], capital taxes and water rentals, as well as benefits from economic activity associated with the construction, such as income and other taxes from construction employment and related business activity. Even a time-limited revised sharing arrangement (such as an exemption of government charges for new projects to the end of 15 years post-ISD of each project) would be a substantial assistance to ratepayers to balance the rate pressures and risks of advancing Keeyask with the 750 MW line, and the government would continue to receive charges for Hydro's existing system.

Absent this mitigation, the K19/750MW plan is *at best* nominally preferred to the need-based plans[12]. However, this is not the only relevant test. Expecting ratepayers to fully absorb the project's risks as well as decades of upward rate pressures in order for the provincial government to collect an extraordinary scale of charges will not be "…superior to potential alternatives…" as per the Terms of Reference item #2 when one such alternative is a revised Plan 5 (K19/Gas/750MW/WPS Sale) with a fairer distribution of benefits.

[11] Note that the record indicates various parties dispute whether the debt guarantee fee is a benefit to government (as opposed to a fee for service to compensate the province for some notional costs that it bears as a result of providing the guarantee) it is clear that (a) no party attempted to quantify any costs that the province bears, (b) the IEC Morrison Park Advisors noted that there is likely no cost in terms of added credit rating pressure today or into the future so long as Hydro is viewed as self-supporting (Tr: 7512 – 7514), and (c) even if the fee were compensating for a cost, no party attempted to determine whether any such cost is in fact appropriately represented by a 1% fee (as opposed, for example, to the previous 0.5% fee in Manitoba as discussed in the hearing in cross-examination between Mr. Antoine Hacault and Mr. Ed Wojczynski (Tr: 3953 – 3955), or the much lower to no fees charged in other jurisdictions as discussed by Mr. Manfred Schulz (Tr: 3106 – 3107) and the report for Newfoundland Hydro referenced in MIPUG/LCA-010a SaskPower and BC (zero or nominal), Quebec and Ontario 0.5%, Newfoundland 0.25-0.5%, New Brunswick 0.6489%).

[12] Mr. Bowman's testimony indicated at Tr: 10197-10200 that under the original assumptions, Plan 4 was generally able to stand on its own without government support (albeit with somewhat more risks than Plan 1, and without any rate benefits for decades). Mr. Bowman also indicated that under updated assumptions, if government rate benefits were sought and secured, Plan 5 (K19/Gas/750MW) would likely be preferable to Plan 1. However, he also noted that if this benefit sharing was not secured and ratepayers were forced to choose between Plan 1 and Plan 5 as presented: "I'm not saying abandon Plan 5" (Tr: 10200). This above position reflects the MIPUG member's view that under any reasonable test of fairness, the role and need for government sharing is much broader than the simple decision making framework (i.e., take Plan 5 or leave it) that Mr. Bowman was addressing.

4) **Added DSM (Level 2) Beneficial, if it's Realistic and Can Be Achieved Without Adverse Rate Impacts:** Hydro's proposed DSM, at a level similar to the Level 2 amounts shown in the series of exhibits for MH-104, is presented as a preferred option. The analysis to date indicates that achieving Level 2 typically drives a net benefit to rates over the first 18 years. As a result, if it is achievable at the projected cost level, it should be pursued. However, Level 2 DSM includes various provisions that may not be realistic (e.g., conservation rates such as stepped rates for residential customers, which the PUB has previously rejected[13]). The aggressive DSM programs should proceed under the following premise:

   i. Programs must be reviewed to ensure they are economic and do not result in higher rates for non-participating customers. This includes a focus on the PACT[14] test (the test of the economics of the program to the utility, as compared to other supply options) and the RIM[15] test (a test of whether the DSM program is driving up rates, and in effect being subsidized by non-participating customers). This must include attention to revenue impacts. The TRC[16] test should be downplayed, as it provides limited analytical benefits compared to the PACT test, and excessively relies upon Hydro's assessment of what is rational for the customer to do economically (which Hydro is poorly situated to do on behalf of the customer).

   ii. The DSM program must include options for industrial customer self-generation with sufficient up front and ongoing support, otherwise it will not result in any energy production. Also, the expanded DSM program should encourage added curtailable load for large energy consumers to derive long-term capacity benefits, rather than focusing solely on energy benefits of DSM.

5) **Minimally Protect Conawapa:** There is no evidence before the Board that pursuing Conawapa for an in-service date of 2026 or 2031 will lead to net rate

[13] Board Order 40/11.
[14] Program Administrator Cost Test. See CAC/MIPUG-I-7(d).
[15] Rate Impact Measure.
[16] Total Resource Cost.

benefits until, at best, many decades into the future. However, this is largely driven by two major issues:

i. Conawapa remains a speculative project without definitive export contracts underpinning its development; and

ii. The provincial government recoveries on Conawapa (through capital taxes, water rentals and debt guarantee fees) are extraordinarily high.

6) For this reason, there is little room for excitement about the opportunity Conawapa offers ratepayers under current assumptions – it brings no benefits and substantial risks. Despite this, there is reason to expect that both of the above issues could be resolved by Hydro within a reasonable period of time – for export contracts it is clear that there will be movement within 12 to 24 months[17], and for the provincial government sharing revisions, this should not take longer than is needed to confirm Conawapa remains a core part of the Province's Clean Energy Strategy (in short, very quickly). In the meantime, there is reason to expect that Conawapa brings a notable upside to Hydro's customers that is not captured in the specific numbers to date, as follows:

i. The high capital cost scenarios for Conawapa continue to be analyzed as a downside, however Conawapa decisions will only be made after the capital costs of Keeyask are known (which has similar cost drivers). As a result, Hydro indicates it is "not plausible" that Conawapa would proceed with high capital cost assumptions (Tr: 6603).

ii. Conawapa has considerable flexibility for an in-service date. Hydro's evidence is that 2026 remains the plan as it best suits potential counterparties (Tr: 2397) but if the economics are improved with delay, 2031 is still fully within the planning horizon (e.g., Tr: 2401; MH Ex 104).

[17] For example, as noted by Mr. Cormie and Dr. Jacobson a SaskPower 500 MW term sheet business arrangements could be worked out "relatively quickly" following conclusions of an interconnection and cost study, that Dr. Jacobson indicates could be completed "within 6 to 12 months" (Tr: 2419-2421). Additionally at transcript page 2417, Mr. Cormie notes: "Great River Energy knows their -- that Manitoba Hydro needs to make an investment decision relatively soon, and -- and given that the current in-service date for Conawapa aligns with the year in which they've indicated they need the power, there will be some urgency for us to come together within the next year on defining something that can be put into a term sheet."

iii. The analysis to date is based on the new transmission being limited to 750 MW. Hydro has now indicated that the 500 kV line is likely to in fact be rated as an 883 MW facility (Tr: 2425) and can be readily expanded to 1100 MW without new facilities in Manitoba (Tr: 2425). If this were to occur the role of Conawapa may reflect a higher value, providing more opportunity for on-peak and opportunity sales.

iv. The analysis to date does not reflect possible added market value due to enhanced connections into Wisconsin as a result of the 750 MW line that is not yet included in the scenarios (Tr: 2427-2428; 1434-35).

v. Hydro indicates that as part of future transactions it could "unwind" its investment in the US transmission, which Mr. Wojczynski indicated could lead to NPV benefits on the order of $100 million to $200 million (Tr:2434-2435). Conawapa could provide the basis for added transactions to help this occur.

vi. The extra firm capacity and energy provided by Conawapa contributes to added reliability and energy security for Manitoba. The reliability and security benefit from Conawapa specifically, as opposed to the 750 MW line, has not been quantified[18], but it is a clear added benefit of Conawapa as compared to Keeyask/Gas/750MW cases.

With regard to protecting Conawapa, the ongoing costs for protecting the project[19] are compared for the next 4 years (to 2018) at $308 million (2014$) to protect a 2026 In-Service Date (ISD), versus only $89 million (2014$) to protect a 2031 ISD[20]. By 2018 Hydro indicates it would be ready for a construction commitment for a 2026 ISD. If another economic review were to occur at this time it would be similar to the current NFAT with regard to Keeyask; far into development stage with very significant amounts already spent. The evidence is not clear that 2026 should now be abandoned, but neither should the Board be satisfied with a lack of a public decision point for at least four years (to 2018) and

[18] The calculations of unserved energy benefit at Chapter 13, page 27 focuses on comparing the PDP to plans without Conawapa and with the 250 MW line, or no line. There does not appear to be a calculation comparing Plans 5/6 (750 MW line) with the PDP.
[19] Provided at PUB/MH-I-238c in 2014$.
[20] Attachment PUB/MH I-279 page 4.

more than $300 million in more sunk costs[21] (excluding added accrued interest). The pursuit of Conawapa should not extend more than two years, or perhaps not past $100-$150 million in expenditures, before some form of simplified public review is undertaken to confirm the direction and if the project in the best interest of ratepayers. The evidence indicates that a decision not to proceed with Conawapa occurring at the end of 2017 would lead to only an added rate impact of an additional 0.07% per year until 2032[22].

[21] Potentially higher. Of note the Keeyask sunk costs to the point of a construction decision exceed $1 billion. By comparison, this Conawapa projection would only result in approximately $800 million in sunk costs, for a much larger project ($376 million to 2014, plus $308 million (plus inflation) further spending to 2018, plus accrued interest over this period).

[22] Exhibit MH-149.

ATTACHMENT 1

MIPUG's Opening Comments on March 3, 2014 by Mr. Antoine Hacault (NFAT Transcript pages 40 – 48)

thank you for your attention.

THE CHAIRPERSON: Thank you, Dr. Miller. I'll now call upon the counsel for the Manitoba Industrial Power Users Group, Me. Antoine Hacault.

OPENING COMMENTS BY MIPUG:

MR. ANTOINE HACAULT: Bonjour, M. President Gosselin. Good morning, Board members. Good morning, all.

Manitoba Industrial Power Users Group is an association of ten (10) major industrial customers operating in Manitoba. The purpose of MIPUG, Manitoba Power Industrial Users Group (sic), is to work together on issues of common concern related to electricity supply and rates in Manitoba.

MIPUG's intervened in each of Hydro's general rate applications since 1988, as well as the review of the Centra Gas acquisition in 1999 and Hydro's major capital projects hearing in 1990, which was the first hearing on Conawapa.

The MIPUG membership currently includes the following companies: HudBay Minerals Inc., located in Flin Flon; Tolko Industries, located in The Pas; Canexus Chemicals, located in Brandon; Koch Fertilizer

Canada ULC, located in Brandon; Erco Worldwide located in Virden; Gerdau Long Steel North America, the Manitoba mill, located in Selkirk; Amsted Rail, the Griffin Wheel Company, located in Winnipeg; Enbridge Pipelines has operations in southern Manitoba; TransCanada Keystone Pipeline, again with operations in southern Manitoba; and finally, Vale, located in Thompson.

These ten (10) companies make up about 20 percent of Hydro's domestic load. Members provide jobs to about fifty-six hundred (5,600) full-time equivalents, and about $2.3 billion to the provincial GDP.

Most members are outside Winnipeg, and many are the largest employers in their communities. MIPUG's concerns reflect the size of the members' investments in Manitoba, which requires a long-term perspective. In addition, MIPUG's concerns reflect competitive market pressures from selling Manitoba products to world markets. We'll hear some reference to competitiveness in Canada and North America, but the reality is even Manitoba companies compete internationally.

The simple point is that rates do matter. They help offset disadvantages that arise from operations in Manitoba such as transportation and distance to markets compared to competitors throughout the world. In this hearing, MIPUG is also endeavouring to provide the Board with a view of the concerns raised during the consultation process with others in the business community in Manitoba.

To that end, there's a been a newsletter, there's been some consultations, and the consultation process will be ongoing as the information continues to be provided and this hearing continues to evolve, and we also expect that some of those members, the chambers, might wish to make some presentations at one point in time.

As we've seen, this hearing is even more intensive than the risk hearing that was quite intensive. There are a few things that it will not cover but are essential to understanding MIPUG's position.

First, industrial rates in Manitoba have risen considerably in recent years since 2004. This has occurred at a time when industrial loads in many other locations have seen prices decline, and be provided with more flexibility to manage power costs. MIPUG's presentation in the recent GRA noted how Manitoba, in its view, was no longer the lowest-priced jurisdiction. One (1) member in particular noted that the power costs in Manitoba were now the fifth lowest of its eighteen (18) plants.

Second, since Manitoba Hydro became regulated in the late 1980s, industry has faced rates that exceed the costs to provide the service. This has tended to be a premium paid by the industry sector of 10 to 15 percent over costs throughout that time period. That cost was about $20 million per year or more that the industry was bearing.

Third, industry continues to have very limited options to manage their power costs in Manitoba, unlike other jurisdictions. The DSM Program, known as cur -- 'curtailable rates' has been capped by Manitoba Hydro, and no additional customers can now participate.

Hydro has no programs that let customers respond to times of high export prices by dropping load, letting Hydro sell power and thus allowing a sharing of revenue between the utility and the -- the industrial customers that might enable that generation of additional revenue. Customers, that's the industrial customers, have waste streams or potential to develop renewable sources of energy, and they basically have no option to generate those and provide power back to Manitoba Hydro.

With respect to the NFAT hearing, it has the potential of becoming overwhelming if it hasn't already, and Mani -- MIPUG suggests a primary focus in two (2) areas. This is taken from the PUB terms of reference.

But firstly, focus on ratepayers' rates and risks. The hearing ultimately ends with a report to the Minister who will make final decisions. If I'm not mistaken, the Minister has many other inputs being provided from other departments and consultation processes. For example, I expect that he's dealing with conservation, economic development, Aboriginal affairs.

We say that the unique wisdom which this Board brings is a good understanding of rates and ratepayers. We hope that this perspective is central to the Board's review and report.

Secondly, focus on the decisions that must be made now. Many of the issues that are going to be discussed are matters that cannot be reversed. Primarily, this includes whether to take up export agreements with Minnesota Power and others, which also requires whether to put a shovel in the ground on Keeyask, and whether to build a US line and, if so, at

250 megawatts or 750 megawatts. These are key decisions that we must address.

Many other issues are informative, but do not, in our respectful submission, require major decisions today. They require decisions that can be altered as time goes on, for example, matters such as what level of DSM to target, whether to be more aggressive and aggressively monitor and pursue more wind generation, or whether -- whether to continue to spend to protect the Conawapa option.

These last examples that I've given are no means an ex -- exhaustive illustration, but we say that those are not critical decisions that need to be made today, and we urge the Board to make sure it gets the large and irreversible questions clearly explored and decided correctly. Other topics can always be adjusted as time goes on.

Focus on rates is key. For industrial customers, the preferred plan shows higher rates for twenty (20) to thirty (30) years in exchange for potentially lower rates over the extremely long term.

This extra cost of investment adds up to a substantial amount. For industrial customers, the total additional amounts paid over the next twenty (20) years is estimated to be over $800 million. This extra cost affects competitiveness, it represents funds that cannot be used to invest in people -- I mentioned the fifty-six hundred (5,600) jobs -- or facilities.

At its core, we submit that the case is relatively simple. MIPUG has framed this as two (2) major questions: Is Manitoba better off with a need-based approach, sticking to its knitting, avoiding debt and commitments as long as possible, letting the current uncertain market climate settle out before committing to future plans; or is Manitoba better off pursuing current opportunities?

If the focus is on pursuing opportunities as opposed to need, the question is asked. Which plan is the best? And as we've known, there have been developments even as recently as Friday, some major announcements on potential contracts, and so I hesitate to say that there's a clear answer to that question, because I don't know what else is going to be coming. But we don't see a really clear answer to that issue or question yet: Needs-based approach, opportunities-based approached.

With respect to the process itself, MIPUG has always expressed the desire to have the least amount of CSI being blacked out and let this process be as public as possible. I, as counsel, have also not signed the undertaking as it was presently framed because of issues similar to what my colleague, Mr. Byron Williams, expressed more recently in his letter.

On another issue, all parties and -- I congratulate all parties for their extreme efforts, including in particular Manitoba Hydro, for the answering of IRs and dealing with evidence. A lot of them have been burning the midnight oil to provide good and complete information to this Board to assist it in making its report.

Mani -- MIPUG, I believe, has one (1) IR to respond to but is making the best efforts to answer them as -- as and when they had come in. We note that -- I don't believe we've received any responses to the IRs asked of the independent experts, and that some reports, such as the La Capra Report, is noted to be work in progress. Hopefully everything continues to unfold favourably so that this Board has complete information by the time this hearing concludes.

Another example has been brought up by other parties, Hydro has apparently provided some updated cases to some parties with respect to the DSM and imports, but we don't believe that those other cases or alternatives have been shared with us fully.

We do not expect to need major changes

and major updates to the prefiled testimony. But if the incoming information leads to a need to provide a small supplement, we will be providing that for the Board and all the parties. And as previously indicated, there may be some brief presentations forthcoming from the business community, such as the Chamber and some of the MIPUG members.

We thank the Board for listening to our opening remarks, and look forward to a productive exchange of information from all parties to assist the Board in drafting its report. I'd be pleased to answer any questions, if there were some.

MS. MARILYN KAPITANY: Messr. Hacault, you -- I think I heard you say that members have no opportunity to provide power back to Manitoba Hydro.

Could you just explain briefly what you would like to see in that area?

MR. ANTOINE HACAULT: That issue was briefly dealt with at the last GRA. There's some of the facilities in Manitoba that could generate power through their own facilities as a result of excess waste, like nitrogen, things like this. So in other jurisdictions the companies have the opportunity to generate those and offset some of the loads. There's programs related to that.

1) What is the Purpose of the NFAT?

The NFAT review is pursuant to the Terms of Reference set out in Order-in-Council 128-13. The Terms of Reference revolve around a PUB report with recommendations to the Minister on "… the needs for Hydro's preferred development Plan and as overall assessment as to whether or not the Plan is in the best long-term interest of the province of Manitoba when compared to other options and alternatives[1]."

The concept of **"long-term"** is not specifically defined, but would generally be understood to fit within typical utility long-term planning periods of approximately 15 years[2], and through to the end of the 35 year detailed study period used by Manitoba Hydro[3], and including the 50 year horizon used for financial analysis and 78 years as used for economic analysis. In short, the Terms of Reference would be understood to suggest that the PUB report is not meant to focus solely on the short-term of 10 years or less when Keeyask and Conawapa construction would dominate the finances, cash flows and socio-economic benefits of the PDP but the project operations phases have not yet had any dominant effect. This is not to say the short-term is to be ignored – otherwise the socio-economic impact of Keeyask and Conawapa construction jobs would similarly be excluded from review, which does not appear to be the intent.

The concept of **"need"** is also not defined in the Terms of Reference, MIPUG explored this with Manitoba Hydro in IR MIPUG/MH I-1 where Hydro provided its definition of need as: "generally to be the requirement for new electrical resources to supply domestic load plus to supply export obligations arising from existing approved export contracts."[4] This criteria aligns with Section 2 of the Manitoba Hydro Act. Hydro clarified that need for a project does not include a requirement to pursue the existing time-limited opportunity for new cross-border transmission, to provide for social criteria such as economic opportunities in the north, jobs, investment, reducing GHG emissions, or achieving any other socio-economic benefits[5] - those latter criteria are simply a basis for weighing various alternative approaches to meet the need, and are not the need itself.

The concept of **"interest of the province of Manitoba"** is similarly not defined. It is clear, however, that this incorporates as a priority consideration to the interests of

[1] Exhibit PUB-2, Terms of Reference, page 2 of 8.
[2] Tr: 1343.
[3] Tr: 314.
[4] MIPUG/MH I-1(a).
[5] MIPUG/MH I-1(b) through (e).

ratepayers. As noted in the August 2013 Overview of the main NFAT filing: "Manitoba Hydro is seeking government approval of the Preferred Development Plan on the basis that it is in the best long-term interests of Manitoba Hydro customers and the Province of Manitoba when compared to other options and alternatives"[6].

The Terms of Reference also specifically request the PUB to review the PDP in light of its alignment with broad provincial Government policy. In respect of the Clean Energy Strategy, that document sets out that "…Manitoba has made the decision to move a portfolio of diverse, new hydro projects through to the readiness stages…" which includes "…planning and design, consultation and negotiation with aboriginal communities, environmental approvals, licensing and permitting..."[7] and further that "…our strategy focuses on building new generation hydro"[8]. While it would appear that the PDP is the only plan that provides the ability to meet this strategy, at least in the next few years, if not throughout the planning period, Mr. Thomson clarified that options other than the PDP can fulfill the Clean Energy Strategy, as follows:

> MR. ANTOINE HACAULT: …So any strategy different than building as set out in this plan wouldn't be consistent with that strategy, so what are we here for?
>
> MR. SCOTT THOMSON: Well, I don't think -- I think that's probably overstating things. Another thing that the energy strategy says is that the province is pursuing a carbon-free economy, but there's natural gas used in the province. There's petroleum products used in the province. We're shifting away from coal.
>
> So it's -- it's -- again, I don't think that the strategy overrides what we're doing here today. It's not -- it's -- it's on balance. You know, does what we're doing make sense in the context of the province's energy strategy? But I can tell you here today we haven't been directed by the province to build these projects (Tr: 239).

[6] NFAT Business Case, NFAT Overview-Meeting Manitobans' Electricity Needs, page 12 of 13, August 2013.
[7] Clean Energy Strategy page 13.
[8] Clean Energy Strategy, Minister's Message.

2) What is the Preferred Development Plan?

The Preferred Development Plan (PDP) is a concept for pursuing opportunities that exist today to develop and advance generation and transmission resources before the date where they would strictly be needed to serve domestic load. The specifics of the PDP were summarized as follows by Scott Thomson at the opening of the NFAT Hearing:

> MR. SCOTT THOMSON: Our analysis shows that even without any new exports, Manitoba will require new electricity resources to meet domestic load, as I said, by about 2023. As such, the Preferred Plan includes the construction of the Keeyask generation station to be in service in 2019, the construction of the Conawapa generating station with an earliest in-service date of 2026, the construction of a 500 kilovolt, 750 megawatt transfer capacity interconnection with the United States at an earliest in-service date of 2020, and new export sales commitments with Northern – Northern States Power, Minnesota Power, and Wisconsin Public Service.
>
> Our Preferred Plan also includes DSM. As you well know, unlike a generating station, the size of DSM is not fixed. It is continually under review by Manitoba Hydro and will be expanded as it is determined to be economic. We believe our Preferred Development Plan is the best long-term solution for Manitoba customers and Manitobans when compared to other options and alternatives, for a number of reasons (Tr: 80 – 81).

It is worth noting that the Terms of Reference do not specifically include DSM as a component of Hydro's PDP under the section headed "The Plan". The only mention of DSM is under the section on "Scope of the NFAT Review" under 1(d) regarding "critical inputs and assumptions" – implying the intent that DSM is a base assumption upon which to build a plan, rather than a component of the plan itself. Despite this limitation, MIPUG has assumed that DSM is also implicitly included under the Board's "Mandate" section of the Terms of Reference, in regard to testing the PDP "…when compared to other options and alternatives".

The PDP has evolved over the course of the NFAT hearing, but was ultimately summarized (and simplified) in Exhibit MH-192 as a series of pathways and future decision points. However, in terms of today's key decision, the practical realities were set out by Mr. Bowman:

> MR. PATRICK BOWMAN: … I think if I was to put the number 1 decision that people need as a hard decision, it's: Do I want a transmission line or not?

> Everything else is subsidiary to that. If I want a transmission line, I need a partner. I need a partner, it's going to be Minnesota Power. If it's going to be Minnesota Power, I've got to have Keeyask, because they want the power by 2019/2020, and I have an agreement that underlines it.
>
> So it really -- every -- it's sort of a trickle down from the question, Do you want more transmission with the US or not? And it's going to change everything in regards to all of your other assessments as well, like DSM and self-generation here, and how customer things evolve (Tr: 10044).

And further:

> MR. PATRICK BOWMAN**:** And I -- I think it's been boiled down in particular with this update by not -- by taking out the 250 megawatt line. We're really into a pathway that involves new transmission and all the things that come with it or a pathway that involves staying closer to home and all the things that come with that.
>
> **…**
>
> Is it -- are we focussing on staying close to home, tweaking and optimizing, putting off decisions as long as we can, doing more DSM, optimizing our offers to an IPP supplier if one comes along, helping customers develop generation where we can, all of those aspects?
>
> And then when we finally get there, figuring out what resource we really need. And it could be Keeyask, it could be gas; but somewhere within that plan, doing this -- this very need-focused plan? Or do we focus on Part 2 of the government's scope of work to you, which is the opportunity side, in which case, you've got another suite of options which you have to deal with (Tr: 10050 – 10051).

In other words, in reference to Exhibit MH-192, the PDP stands as a contrast to a Need-based pathway. The concept of a Need-Based pathway was described in the evidence of Mr. Bowman as well as an expanded creative concept in the La Capra “no new generation” scenario, known as Plan 17. At its core, this Need-based concept includes the “base case” that has been used consistently to compare with the PDP, Plan 1 (All Gas), as well as Plan 2 (Keeyask when needed sometime between 2023 and 2031) and as such is not a concept that advocates solely for gas:

> MR. PATRICK BOWMAN: … [T]he need-based pathway doesn't mean All Gas, it doesn't mean build gas. It means do everything else you can until you have to build something, and at that point, it could be as simple as gas.

> It could be anything else, but really, it's the, put off the decision and know that in your back pocket, you always have gas as - - that can be developed quite quickly (Tr: 10055).

One defining characteristic of the PDP is the high degree of provincial socio-economic benefits, and especially government revenue benefits, as compared to all other plans. By far the government gets more revenues from the PDP than any other alternative plan (through capital taxes, water rentals and debt guarantee fee).

In contrast, the PDP is not superior for ratepayers on traditional economic metrics. The NPV benefits of the PDP are now effectively zero compared to All Gas scenarios[9], and far behind the NPV benefits of other reasonable alternatives such as Plan 5 or 6 (K19/Gas/750MW) (similar to the PDP but not pursuing Conawapa). Further, the PDP has the highest customer rate increases projected for the next twenty years compared to major alternatives, with long-term rate benefits between years 2031-2061 that must be viewed with caution[10].

With respect to complementary activities, it is clear that Hydro now plans to pursue an expanded DSM initiative. Whether this is viewed as part of the PDP or not, there is a distinction between major decisions at a given point in time (such as committing to Keeyask construction, or to an export agreement) and flexible decisions that can be readily adapted in the future, or reversed, or commitments that can be made much closer to a need date[11]. As noted by Mr. Bowman:

> MR. PATRICK BOWMAN: … optionality and decisions unfolding over time is key to working through something like this.
>
> It's not necessary to decide everything today. Matter of fact, it's not even advisable to decide everything today. It's advisable to decide the things you have to decide, and then set out the processes needed to make the other decisions. The press -- put the pressures where they need to be. Put the decision points where they need to be (Tr: 10040).

[9] Exhibit MH-95, slide 130 – Plan 14 with Level 2 DSM.

[10] Rate projections in the years beyond 2031/32 must be viewed with caution as: (a) they are highly speculative, and (b) they suffer from the "Conawapa now versus Conawapa never" fallacy addressed by Mr. Bowman at Tr: 10083-10085, and Tr: 10134-10135.

[11] This would include DSM, but also items such as wind, which Mr. Wojczynski noted in the September 6, 2013 Technical conference: "…I imagine we are going to be doing wind down the road." (Tr: Sept. 6 2013, page 376).

The 750 MW US Interconnection and the advancement of Keeyask need to be decided today.

> MR. ED WOJCZYNSKI: But one (1) of the pieces of information we have right now that if we in June 20th said we'd been collectively -- PUB recommend/government decide that we're not going to accept proceeding with interconnection and Keeyask for '19, that we want to wait two (2) years and decide then, one (1) piece of information we have today is that in all likelihood that option will not be available as two (2) years from now.
>
> We could probably make export sales two (2) years from now, maybe not to Minnesota Power. And Mr. Cormie talked about that a bit the other day. But the real window of opportunity we have is for the interconnection infrastructure.
>
> Manitoba Hydro fully expects that two (2) years and five (5) years and ten (10) years from now, that, assuming we have firm surplus available in the future, we'll find export sales and we'll be able to sell it. And the price would be the market price then (Tr: 2308 – 2309).

Based on the decision to proceed or not proceed with the 750 MW US Interconnection and Keeyask advancement today, the export contracts that are either confirmed or in the works will follow suit.

> MR. DAVID CORMIE**:** With these contracts, these utilities are choosing not to build alternate supply resources, but to rely on Manitoba Hydro as the supplier. Without these contracts, these utilities will invest in other long-term supply options to meet their needs. The opportunity for Manitoba Hydro to displace these other options will not return. They will be lost.
>
> The contracts that have been signed to date for hydraulic energy effectively use up most of the surplus power -- hydro power available from Keeyask. However, export discussions with Wisconsin Public Service, Great River Energy, and Saskatchewan Power and others continue, mainly for the power from Conawapa (Tr: 1312).

In contrast to Keeyask advancement, the 750 MW US Interconnection, and the related export arrangements with at least Minnesota Power; a firm commitment to proceed with Conawapa does not need to be decided today, nor should it be. The economics of Conawapa, as it exists today is not in the benefit of ratepayers.

> MR. PELINO COLAIACOVO: I would consider Conawapa today as -- not to belabour the point, but to be a development opportunity. And in pursuing any development opportunity, a project developer seeks to

> arrange as many supportive commercial deals as possible. But construction of Conawapa is at least ten (10) years away. Even in the -- in the best-case scenario, I believe it's twelve (12) years away. It could be longer. And I believe that WPS would have a full understanding of that, that it is the subject of debate and discussion, and its timing is not clear, and the ultimate disposition of it is not clear.
>
> I think that's very different from the arrangements that have been made with parties on Keeyask, where the environmental permitting and approval process is basically done, where over a billion dollars have already been spent on the project, where construction contracts have been signed, where, you know, the project is imminent to be constructed. And so the issue of the impact of a choice being made is very different, I think. And commercially it would be well understood by all the parties. The burden on Keeyask is much higher because of all of the investment that's been made in it, so a choice not to proceed with Keeyask should be done only for very strong reasons. Whereas on Conawapa, because of the speculative nature of Conawapa as of today, and I think everyone – every reasonable and rational outside observer would believe that there is lots of questions around Conawapa, would have a very, very different impact (Tr: 7441 – 7442).

There are many different future opportunities that may make Conawapa more economically viable for ratepayers than it is today. But that remains to be determined, hopefully in the near future.

> MR. SCOTT THOMSON**:** We also view the MOUs as an indication of strong commercial interest, and an important step on the road to future sales contracts. Virtually every one of our existing firm export contracts was preceded by an MOU. As well, our 500 megawatt contract with Xcel is up for renewal and repricing in 2025. This would have to be supplied from Conawapa. There won't be capacity to renew that without it.
>
> So where does leave us with our Preferred Development Plan? Keeyask is sold out, as I've said, and the benefits of the new US interconnection can be realized with this project. Prospects for Conawapa are very promising. Assuming Conawapa proceeds, the recently announced 308 megawatt WPS sale would utilize about 30 percent of its dependable energy output. Even partial successes under the 600 megawatt MOU with GRE, and the 500 megawatt MOU with SaskPower, could fully subscribe the balance of the firm energy available from Conawapa until we grow into the demand (Tr: 92 – 93).

Similarly, the precise DSM levels do not need to be decided today. A broad commitment to a particular scale of DSM is beneficial as part of major decisions being made today. However, the precise level of DSM should only be decided as plans arise that pass economic tests, such that ratepayers who do not undertake the DSM initiatives are not burdened with rates that are set to pay for the plans and cross-subsidize other ratepayers who are targeted for efficiency savings.

3) Is There Sufficient Information to make a Decision Today?

MIPUG submits that it is critical that the PUB provide a clear decision and direction regarding the major building blocks of the PDP (most notably Keeyask 2019, the 750 MW transmission line and the related 250 MW sale to MP). This is needed to fulfill the Board's Terms of Reference to report no later than June 20, 2014, and to fulfill the pressing decision that must be made in regard to Keeyask contracts. As noted by Mr. Thomson:

> MR. SCOTT THOMSON: There's -- there are some provisions in the contractual arrangement that we have with Minnesota Power that would allow for regulatory delay. If a proj -- projects that get delayed tend to cost more money. We're in a position where we're ready to go this summer. We've identified the contractors, and we have made investments to date in the project. So if the -- if it's put on hold, it's almost certainly to cost more in the long run (Tr: 116-117).

In regard to the decision-making, the Board is in possession of extensive written material and over 10,000 pages of transcript for this proceeding. This, however, is not determinative to whether the Board has sufficient information and certainty to recommend the best course of action. The question instead goes to uncertainty, perceived information gaps, and confidence. In this regard, Mr. Bowman noted the following:

> MR. PATRICK BOWMAN**:** The second preliminary comment I would - - I'd want to make is I've been through a number of different processes like this, and a lot of hearings on different subjects, and I can't remember hearing where the Board has had as high a quality of advice and information put to it as this one.
>
> …
>
> I think that there has been some exceptional work done. I think you've had Manitoba Hydro's A-team in respect of economics. It's the best Manitoba Hydro has to offer, and although I'm always a skeptic about new people coming in and managing to find their feet on a system as complicated as Manitoba Hydro is, I think people like Morrison Park did a very, very good job, and I think you should -- I'll try to, as I work through my comments, not spend time dwelling on things that I think they have covered very well.
>
> La Capra did a very good job in respect of the -- some of the economic work. Some of the other parties, Mr. Harper is always predictably useful

> and interesting. So I think that -- hope that will make my presentation shorter as a preface, and, in particular, I would say, as I move on to number 3, that I think that with that exceptional advice, I think the degree of disagreement that is before you and that you hear listening to the debates for someone who is in this business is actually fairly small (Tr: 10039 – 10040).

This is not to say the information base is perfect – it never is. Mr. Bowman explained:

> And it's my -- I don't know if it's meant to be soothing or not, but this is all part of a normal planning exercise. There -- uncertainty doesn't always get resolved as you go through it. This is part of the life of resource planning. As much as we want to crystalize the planning to a document, it's never crystalized. It's a moving target (Tr: 10109).

In short, there will always be uncertainty. There always is in power resource planning. But it cannot be a reason for failing to make decisions, and in fact is part of the very basis for the plans put forward by Hydro. As described by Dr. Borison and Mr.Cormie:

> DR. ADAM BORISON: … And I guess the point I would like to emphasize is that this is an industry that has been, for decades, quite dynamic, quite changing, and quite uncertain. And that I was looking back in the literature for the use of the term 'unprecedented uncertainty', which I have used, and Dr. Murphy has used. And I found that in every single year, at least going back ten (10) years on the Internet, and then I actually found an article from 1983 about -- that said the utility industry is facing unprecedented uncertainty.
>
> But I actually don't think that's untrue. I think what 'unprecedented' means in that context is there are a set of things that appear very uncertain right now that haven't been there before. And so in '83 it were -- was things like Three Mile Island, or something of that nature, electromagnetic fields. There were issues that were there that people had never heard about before which all of a sudden made things very uncertain.
>
> I think the fantasy though is that somehow those are going to go away and what happens instead is those go away -- I mean, we now don't worry so much about electromagnetic fields -- but something else shows up. And so I -- again, to defend myself and Dr. Murphy, I think he'd say, Yes, the uncertainty is different. Now it's structural uncertainty. It may be uncertainty about the nature of the market in MISO. It may about regulation in California.
>
> But it is not as if somehow we can wait magically for a few years and the uncertainty will go away, because most likely what's going to happen is

there'll be some other issue that comes up. And I think the past thirty (30) or so years have been evidence of that.

…

MR. ANTOINE HACAULT: …What's your view as to what the uncertainty does with respect to your negotiations? Does it help you get better prices?

MR. DAVE CORMIE: Yes, clearly that's an advantage that works in our favour, because it's not only Manitoba Hydro that uses a consensus forecast and goes to multiple forecasters; our customers also do exactly the same and they're making their forward decisions based on the exact same information that we have. Gas prices could be ten dollars ($10) in the future, it could be eight dollars ($8), it could be four dollars ($4), it could be three dollars ($3).

And so it shouldn't be a surprise that their view of the future is not much different than ours and they are risk averse just as we are.

And in talking to them -- and their customers are very similar to our customers. And the first thing they want is a reliable supply of power. And the second thing they want is stability in pricing. They don't want to be exposed to volatile pricing. The third thing they want is absolute price. But absolute price is less important than stable pricing.

And so when they look at the future and they see this uncertainty, they want to hedge against that. And the price that we're able to achieve in our forward selling reflects a premium over what you would expect if you just did the engineering analysis of what the future costs of electricity might be.

So the uncertainty in that regard helps us to achieve premium pricing, because we can offer fixed price, long-term contracts that are stable, and that eliminates a lot of utility risk, and they're paying for that.

MR. ANTOINE HACAULT: And to the extent that you're able to negotiate firm con -- firm price contracts for part of your dependable energy, you make use of that uncertainty to reduce the uncertainty in Manitoba Hydro. Am I getting it right?

MR. DAVID CORMIE: Yes. So we then -- I have fixed price contracts for power off Conawapa going out to 2036 for the Wisconsin Public Service sale. That locks up, essentially, a third of the production of that station at a -- at a price that's well above our levelized cost, and -- and that helps us make a better business case to build that project (Tr: 2560-2563).

In short, it is MIPUG's submission that the Board has the information needed to make a clear decision in regard to the primary required questions (Keeyask 2019, 750 MW line, MP 250 MW contract) and that delay on these matters is both (a) likely adverse to project cost control, and (b) unlikely to resolve or provide a future decision point where the decision will be any easier. In fact, even if Dr. Borison's "fantasy" arises of significantly reduced uncertainty in power markets or GHG emissions policy, such an outcome may make development of Manitoba's hydraulic resources harder as it removes some of the most attractive attributes of Hydro's commercial exportable product.

4) How Does the Current Context for Manitoba Hydro Rates and Finances Affect the Decision?

Manitoba ratepayers faced substantial upward rate pressures in the past decade and this is expected to continue into the future regardless of the development plan chosen. In discussing Manitoba Hydro's financial forecast in Exhibit MH-97 (IFF13) the rate increases were predominantly explained to be due to costs to the existing system:

> MR. DARREN RAINKIE: So as you can see, net income is expected to be thin in the next ten (10) years, even with the 3.95 percent projected rate increases, primarily due to the capital expenditures that are required to renew aging infrastructure and provide reliability of the electrical system such as Bipole III.
>
> This will be further challenged when the in-service of the Keeyask generating station comes into service, but net income is expected to rebound sharply after the in-service of Conawapa generating station (Tr: 2732).

This reflects well over ten to fifteen years until the projected sustained rate increases have any prospect of subsiding.

The current hearing is not to address any options as to how to pay for the changes to the existing system (including Bipole III, as per the Terms of Reference) and the sunk costs spent to date on Keeyask and Conawapa ratepayers. Those will be matters for future General Rate Applications (GRAs). However, the existing rate pressures must be considered as part of deciding on the development plans:

> MR. BILL TURNER: When Manitoba Hydro advances the in- service date of its new plants, there's more room to meet unexpected load growth by all industries. For all these reasons Manitoba Hydro has been a good partner for industry, and future hydro developments should be something industry supports.
>
> Today's PDP proposal, however, has some notable challenges. First, industry Manitoba has been challenged by steady power rate increases of more than 40 percent since 2004, which also includes a requested 3.95 percent for April 1st of 2014.
>
> Throughout this entire period, Hydro has produced cost-of-service studies that show industry paying up to 10 percent or more above its costs. Yet all rate changes were implemented on an across-the-board basis. Initially, these are rates – increases were presented as a decade of investment,

> with a decade of returns occurring promptly thereafter. With each subsequent financial forecast, these returns become more diluted and out of reach (Tr: 7205-7206).

The impact of the PDP on the above context is significant to ratepayers, and in particular to industrial customers. Hydro's main evidence in respect of elasticity studies that it commissioned was provided in an Attachment to CAC/MH I-040a (a copy of an IR from a 2007 GRA) where it noted that the expected industrial Own Price Elasticity of Demand was double that of the other classes of customers[12]. This means that the load response of industrial customers (a measure of sensitivity to price changes) is, on a relative basis, high.

For General Service and Industrial customers the following notes the rate related effects of the PDP that are expected to occur:

> MR. BILL TURNER: In regard to the NFAT process, the original numbers, we were provided for comparative rate impacts showed that the PDP may have a .5 percent higher impacts each year, compounding for almost twenty (20) years at 3.9 percent -- 5 percent per year, compared to three point five (3.5) if Hydro just focussed on Keeyask and new transmission.
>
> Just comparing these two (2) numbers, industry would end up paying a sum of 400 million more over the next twenty (20) years for the PDP rather than viable alternatives. This is $400 million that will not be available to Manitoba -- Manitoba companies to invest in expansion, employees, community support, and other actions that may help with competitiveness.
>
> We were informed new numbers may show the impacts being even larger. At the same time, we were informed the provincial government will significantly increase its recoveries from Hydro with this plan. This, in fact, underlines the NFAT challenge.
>
> In principle, MIPUG is among the first to support hydro development in Manitoba. However, Mani -- MIPUG will have to undertake a careful review of the financial evidence in this hearing before it will be able to make a decision as to whether the full PDP is in the best interests of -- of ratepayers (Tr: 7207-7208).

Rate effects in the medium-term can have rippling effects throughout the Manitoba economy, just as much as the long-term horizon of this hearing:

[12] Industrial -0.125; commercial -0.06; residential -0.056.

> MR. PELINO COLAIACOVO**:** I think the point that we are making here is that while most customers in Manitoba do not have the option to opt out of the -- of Manitoba Hydro rates, there is a relatively small pool, but potentially very significant customers, that are mobile in the medium to long term.
>
> We had the opportunity to review confidential information that Manitoba Hydro provided to us which provided greater detail on the identity and characteristics of some of the largest customers. And we reviewed the investment patterns of those customers and the frequency with which they make investments in their facilities, for example.
>
> And -- and a certain number of those customers make investment decisions on a ten (10) year basis, for example. And so rates -- the rate horizon, the rate forecast, on a ten (10) or a fifteen (15) year basis would be very relevant to their business decisions. And those customers that are high users of power do occasionally -- well, let's put it this way. Electricity -- expected electricity rates over the medium term are -- is very relevant to their investment decisions and they can choose to go elsewhere. There are other jurisdictions that are competitive.
>
> And that's the point that we were making in this paragraph, that it is relevant – excuse me -- to consider whether some customers can opt out of the system by taking their business elsewhere, and that if they were to choose to do that there would be an impact on the customers remaining in the system (Tr: 7475 - 7476).

In regard to the basic impacts on the socio-economic environment of Manitoba, every rate increase matters and has an effect on ratepayers.

> MR. BILL TURNER: One (1) of the best examples we've had of why rates matter and why it's not just a matter of being a bit below the next best jurisdiction came from the mining members. They have a very compelling example to emphasize the importance of power cost to their industry.
>
> With some theatre, they will drop a piece of Northern Manitoba geology on the table and pose the question: Is this valuable ore or just worthless rock? It turns out that this is a trick question, as the difference between rock and ore is not geological, but economic.
>
> There are some valuable minerals in all rock, ore that is material that can be profitably mined to create exportable products, jobs, and industry. This is dependent on international competition, product demand, and the price of the product, but also on the cost to mine and process the material.

> Electricity costs are a key element of determining what is ore and what is rock. All things being equal, lower prices for power means more ore, more jobs, and more activity (Tr: 7202 - 7203).

In the same period, due to re-investment in the Hydro system and development of Bipole III, Hydro is expected to increase its debt levels dramatically regardless as to the plan chosen. It is important to note that the different resource options come with very different levels of debt for Hydro:

> MR. PATRICK BOWMAN: And there can be a lot of different comments in respect of this debt and how self-supporting debt should be looked at and what it would mean to a credit rating agency. But at a basic, fundamental level, it's -- an unavoidable piece of understanding the plan is that big plans come with big debt.
>
> And it is -- it must be managed. It has to be considered, but it's a number that shouldn't be forgotten, that we're talking about commitments that are multiples of the type of debt that's been taking on by public sector or public sector agencies in Manitoba to date. And we've heard this comment time and time again from members of the business community (Tr: 10035).

This matter was address by Manitoba Hydro, as follows:

> MR. MANFRED SCHULZ: …To the degree that Manitoba Hydro remains self-supporting in keeping with the importance of our financial ratios to the extent that we remain self- supporting, there should be no significant impact on the credit rating for the Province of Manitoba (Tr: 3369).

Morrison Park Advisors provided more detail, as follows:

> MR. PELINO COLAIACOVO: …So -- I mean, your basic question that you opened with was, Does debt matter? And I think at the margin debt does matter. But, you know, the analysis that we went through to try and put it into context does -- do any of the levels of projected debt present an unacceptable risk to the province? It doesn't appear so when you go through this analysis.
>
> Does one (1) plan offer more of a risk, relatively speaking, compared to other plans? Yes, you can make those kinds of judgments that one (1) presents slightly more risk than another plan. But the risks are all relatively remote, because a whole -- there has to be a confluence of negative factors happening for any of those risks to become real, to be actualized.

> But it's not a black or white question.
>
> MR. ANTOINE HACAULT: Thank you very much. Does it make a difference that under these assumptions that we've just made that Manitoba's at 20 billion and Hydro's about -- is over half, it's close to 30 billion? It's all Manitoba debt, but 30 billion relates to Hydro and 20 billion is tax supported.
>
> MR. PELINO COLAIACOVO**:** Well, I think the other thing to recall is that even in a very negative scenario Manitoba Hydro will still be producing revenue. It may produce less revenue than ideally you'd want it to, but it will still be producing revenue.
>
> So it would never be fair to assume that the entire debt of Manitoba Hydro would land on the books of the province. The risk is only that in an extreme situation a fraction of Manitoba Hydro's debt would land on the books of the province. So, you know, the total debt is very much a limiting and calamitous case. It's not anything that you -- that -- that would reasonably, under almost any circumstances, be expected to occur (Tr: 7513-7515).

And more specifically:

> MR. PELINO COLAIACOVO**:** There's no single metric that you can point to to say, This thing is going to change the perceptions of the markets that Manitoba Hydro is financially self- supporting or not.
>
> Drought on its own will not be enough. Decline export prices on their own might not be enough. Capital cost overruns on their own might not be enough. A pattern that occurs over an extended period of time might well be enough, and a pattern might be made up of ingredients from several different directions.
>
> But it's impossible to put a finger on any single thing and say, that will turn the tide. And at the same time, recognizing that Manitoba Hydro has lots of tools on its own to respond to challenging situations (Tr: 7523-7524).

A major focus for the decision today must consider that (a) rate pressures on customers are high regardless as to the plan; (b) that this pressure creates real and adverse impacts on customers and in particular on industrial loads that help underpin the system and the development plans. At the same time, the larger plans come with large debt which in theory could limit the ability to mitigate the rate impacts. However, while this debt is cited as a concern by the broader business community, the evidence is that this debt is readily manageable, is highly unlikely to lead to any adverse impacts on the provincial credit rating under even extreme adverse conditions (and further even if there were severe financial pressures at Hydro at most a fraction of Hydro's debt would be considered not self-sustaining - this fraction of debt would remain well within the province's ability to defend to credit agencies).

In short, a significant question for the PUB in adopting one of the larger "opportunity-based" development plans today is whether tools are available (including revisions to Hydro's debt:equity targets) to help manage significant rate pressures that such a plan could exacerbate. The evidence in this proceeding (particularly Exhibit MH-104-12-6 and summarized in MH-104-12-5) is that such tools are available (subject to ongoing review by the PUB), particularly Table 3 from that document:

Table 3 from Exhibit MH-104-12-5

Table 3 outlines the cumulative rate increases.

TABLE 3 CUMULATIVE RATE INCREASES AT DSM LEVEL 2 USING ALTERNATIVE METHODOLOGY #2 AND REFERENCE CAPITAL COSTS		
	2031/32	2061/62
ALL GAS (1)	51%	162%
K31/GAS (2)	53%	145%
K19/GAS/250 MW (4)	52%	130%
K19/GAS/750 MW (5)	53%	130%
K19/GAS/750 MW (6)	53%	128%
K19/C40/750 MW (12)	54%	114%
PDP (14)	69%	96%

As shown in Hydro's Table 3 above, the rate impacts over the near to long-term (to 2031/32) under this hypothetical rate setting methodology are contained to approximately the same level for all plans other than the PDP. For the PDP benefits only arise over the extreme long term (to 2061/62), unsurprisingly, the long-term benefits exist in increasing degrees for any plan that commits in a larger way to inflation protected assets (hydro plants and transmission lines). However, in order to achieve the above degree of near-to-long term rate protection it must be accepted that Hydro will only secure a debt:equity ratio of somewhere between 80:20 to 85:15 by 2031/32. This is inconsistent with Hydro's presently published (and vigorously defended) financial targets, and therefore should be viewed with skepticism.

5) Has Manitoba Hydro Adopted a Reasonable Approach to Planning?

MIPUG's view is that Hydro has ultimately adopted a reasonable approach to the NFAT, albeit in a manner that is different than utility resource planning in most other jurisdictions. These matters were highlighted in the evidence of Mr. Bowman:

1) Hydro's analysis "in many places goes well beyond that provided by most utilities undertaking a resource planning exercise"[13]. In particular, Hydro provides a full economic picture of the utility resource requirements over 35 years (extended to 78 years), and a full financial analysis of the entire utility operations over 50 years. Most utility resource planning exercises will constraint the exercise to only the impacts of the incremental resource addition, and will not consider how to meet the entire utility load over the long-term, just the alternative means to meet the load represented by the resources under debate (e.g., Keeyask at 3,003 GW.h dependable energy)[14].

2) Hydro's planning is exceptionally long-term in nature. This is beneficial when considering hydraulic resources, but attention must be paid to the fact that ratepayer impacts occur over all horizons, not just the very long-term. As such it is critical to look at the perspective of ratepayers "investing" in the system over constrained periods (which would still be considered long-term such as 15-20 years.

3) Hydro's original filing insufficiently considered the optimization of a "Need-based" plan before proceeding to review the larger opportunities provided by exports. This included an incomplete assessment of DSM. Mr. Bowman addressed this issue in his direct testimony, both in respect of how the original filing could be viewed (given its insufficiencies), as well as the view with the updated DSM information:

> Mr. PATRICK BOWMAN: Is it -- are we focusing on staying close to home, tweaking and optimizing, putting off decisions as long as we can, doing more DSM, optimizing our offers of -- of -- to an IPP supplier if one comes along, helping customers develop generation where we can, all of those aspects?

[13] Pre-filed Testimony of Mr. Bowman, February 5, 2014, page 3-1.
[14] MH/MIPUG I-2(a).

> And then when we finally get there, figuring out what resource we really need. And it could be Keeyask, it could be gas; but somewhere within that plan, doing this very need-focused plan? Or do we focus on Part 2 of the government's scope of work to you, which is the opportunity side, in which case, you've got another suite of options which you have to deal with.
>
> And at the time, we were trying to wrestle with fourteen (14) plans and five (5) options. I think this is redundant now that it's really boiled down to, Do I want transmission or not, in a way, the decision. It's all -- it's a bit of the -- of the same conclusion.
>
> We were lamenting -- using this in part to lament that I -- it seemed to me that the NFAT moved quickly to advocating a Preferred Development Plan before fully exploring what the need-based plan could look like. And I think at one (1) level, that causes some confusion and suspicion, that I'm not dealing with a clear set of information; I'm dealing with an advocacy piece.
>
> I'm not as concerned about that now, but I would have been more comforted if Mr. Thomson had not said, We're here to advocate for a plan, as opposed to just be an honest broker to Manitobans about what best direction to go. But I think, in practice, as the hearing's unfolded, we've gotten information to be able to do this now; that I think the DSM scenarios are critical. I'm glad we've gotten them.
>
> I didn't -- in all honesty, I'll fess up, I didn't expect the DSM scenarios to be available in the time frame that was in the hearing. And so when we reviewed the documents, the first thing on our mind is, is there any way with the documents here the Board could get to a decision by next June, given it's got this big hole in terms of DSM.
>
> And we turned our mind to this is not an IRP. This is -- it's not an integrated resource plan. It's something different. It's an assessment of a business case of an opportunity. And despite the fact that it's not product 1, it's not an IRP, can I still work with it as a business case for an opportunity. And we thought you could get there.
>
> I'm much more comforted that we actually have the information now that is more fulsome. And I think that's an advantage. It's one (1) of the things that I think has improved over the course of the hearing (Tr: 10050-10052).

(a) Is Hydro's Load Forecast Reliable?

Hydro's load forecast is one critical underpinning of the resource planning evidence, but at the same time such a load forecast must always be understood to be relatively speculative. All plans must consider the high likelihood that the load forecast will be reasonable over the short term, but will be not just imprecise (as all forecasts are ultimately imprecise), but significantly different than the future reality over the medium to long term. Mr. Bowman noted the load forecast used “reflects a reasonable approach to assessing the NFAT plans”[15] but that “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” [16].

MIPUG has concerns that Hydro is over-confident in the reliability of its load forecast. In particular, Manitoba Hydro indicates that it tests its load forecast capability based on a standard of being within +/- 10% over ten years:

> MR. ANTOINE HACAULT: Hydro's goal, as I understand it, for the ten (10) year metric is to achieve 10 percent accuracy, and that would be what you can reasonably expect to achieve for a ten (10) year forecast. Did I understand that correct?
>
> MS. LOIS MORRISON: Yes. We believe that the forecast is reasonably performing if we are within 10 percent (Tr: 1065).

It is worth noting that 10% of domestic load is approaching 3,000 GW.h, or approximately the dependable energy from Keeyask. In terms of actual performance against this metric, over the past 20 year history, on 5 occasions the load forecast has been out by approximately 10% or more over 10 years[17] (i.e., 5 forecasts out of 20, or 25% of forecasts were out by this amount). However, Hydro’s load forecast projections indicate that on a go forward basis looking 10 years into the future, there is only a 5 percent chance of being out by more than +/- 8.6%[18]. This would appear to be excessive confidence compared to past performance.

While DSM and other technology innovations may lead to a lowering of future growth, Mr. Bowman notes that disruptive technologies that lead to load increases, and the arrival of new industrial customers need to also be considered:

> MR. PATRICK BOWMAN: …Hydro may not show enough possible variability in its load forecast with respect to sensitivities in testing hydro

[15] MIPUG-9-2, Pre-filed Testimony of Mr. Bowman, Revised February 28, 2014, page 3-11.
[16] MIPUG-9-2, Pre-filed Testimony of Mr. Bowman, Revised February 28, 2014, page 3-11.
[17] Exhibit MIPUG-20-2, page 23.
[18] Per Exhibit MH-103, the range from P2.5-P97.5 (a 95% interval) shows the outer bounds of 26503 GW.h and 31522 GW.h as compared to the base domestic forecast of 29013 GW.h. This is a variation of +/- 8.6%.

> balance. I think that's been highlighted by some of the changes that have occurred and that -- and as well as the DSM scenarios
>
> …
>
> And I think that it's highlighted that, in respect of resource planning, some further outer scenarios on load forecast probably would have been beneficial. I think we're better off now with the pipeline assessment being included, because it gives you an example of what could happen on the upside (Tr: 10106-10107).

Mr. Bowman also noted that above and beyond the pipeline expansions, there are other material industrial loads that could arise in the time frames for planning, which was discussed at MH/MIPUG I-4(a) and Transcript pages 10059-10060.

In this proceeding, the economic analysis is beneficial in helping to determine how critical the load forecast is to the outcome, as per Exhibit MH-171 (Revised):

- For the PDP, the evidence is that this plan benefits from higher loads. The PDP has an NPV of $374 million over Plan 1 (All Gas) with updated assumptions and base DSM. If the load drops due to adopting DSM Level 2 the NPV becomes $45 million. However, the NPV rebounds to $139 million under the same assumptions but with the pipeline added.

- In contrast, for Plan 5 (Keeyask 2019, 750 MW transmission) without Conawapa, the equivalent NPV's are $377 million (over Plan 1 – All Gas), $410 million (adding DSM Level 2), and $339 million (DSM Level 2 with pipeline load). These differences are not material in the context of a 78 year analysis – in short, the Keeyask/transmission plans without Conawapa are effectively insensitive to the load forecast.

The most distinct analysis is contained in Exhibit MH-156. This exhibit (page 2) provides that the same Plan 5 developments (Keeyask 2019, 750 MW Transmission) with no load growth in Manitoba still provides an NPV of $402 million.

With this factual foundation, the ability to assess advancing Keeyask to 2019 and the 750 MW transmission line with imperfect load forecast information is robust. However, the load forecast does become a relevant risk factor for assessing Conawapa. As such, before Conawapa is approved, further analysis of more extreme load forecast scenarios is required.

(b) Should Monte Carlo Modelling have been Used?

Manitoba Hydro used a scenario model based on inputs and assumptions associated with reference conditions, using high and low scenarios for some of the analysis. The high/low scenarios were used to create the “quilt” and S-curves. The full set of high and low variables were only provided for the 2012 assumptions and not for the 2013 updates.

An alternative approach to modelling is the Monte Carlo approach, as described by Morrison Park Advisors:

> MR. PELINO COLAIACOVO: We made comments in our report and in several IRs about the method of modelling and testing. What has been assumed is ranges of economic and capital cost and energy price variables at high, reference, and low.
>
> And those were applied to extended periods of time. There is a different kind of modelling, referred to as Monte Carlo modelling, which actually tests scenarios where the prices of different variables change on an annual basis according to a probability curve for each individual variable. And so that kind of modelling allows, arguably, a more realistic perspective on the future, where prices are constantly changing. Interest rates are going up and down. Capital costs have a wide range of potential outcomes.
>
> It's clearly a kind of modelling that is time consuming and challenging. But for an inte -- for a resource expenditure in the multiple billions of dollars, it's appropriate to undertake that kind of modelling, in our view.
>
> MR. BOB PETERS: That wasn't done in the current situation?
>
> MR. PELINO COLAIACOVO: No, it was not. I believe there was references to Monte Carlo modelling being used in some of the construction cost analysis, but Monte Carlo modelling was not used in the overall analysis of the different resource plans.
>
> MR. BOB PETERS: Does that suggest then that Manitoba Hydro would have to create a different model, or is it something that can be...
>
> MR. PELINO COLAIACOVO: There are off-the-shelf modelling programs available for Monte Carlo modelling, three (3) or four (4) that are commonly used commercially. They would have to be adapted to the particular circumstances of Manitoba Hydro.

> Manitoba Hydro has a particular challenge in its modelling because of the fact that it's primarily a hydrology-based system. So there is no question that using Monte Carlos to help modelling coupled with hydrological variation is a daunting challenge. We're not trying to minimize that. But it may prove to be a useful type of analysis in the future, rather than the probabilistic scenario modelling that was used for the purposes of the NFAT (Tr: 7598-7600).

MPA also noted in response to PUB/MPA 1-001:

> All analytical methods require judgement: in Manitoba Hydro's case, the definition of High/Reference/Low scenarios required judgement (especially because of the linking of several variables each into groups referred to as "energy prices", "economics" and "capital costs"), and the assigning of probability-weightings to each of the cases is obviously an exercise in judgment. In a Monte Carlo model, defining probability distributions for each variable is also an exercise in judgement. There is no perfect solution, but a Monte Carlo style of modeling exercise may have provided additional useful data for analysis in the case of Manitoba Hydro.

MPA correctly highlights that Monte Carlo analysis can provide some useful insights into the ranges of possible outcomes. However, there are also notable drawbacks. Dr. Higgin noted that the use of Monte Carlo analysis for the preparation of full resource plans in Canada is not the norm:

> DR. ROGER HIGGIN: You can use other tools for some of those elements. For example, use Monte Carlo methods if those -- linear programming. And these are sometimes used in planning processes like this.
>
> However, I think right now in most Canadian jurisdictions, it's the way you've just described it. The -- come up with the high, low, and medium estimates, maybe apply risk analysis to those, see what the -- develop scenarios, and then give it your best shot when you've got all that (Tr: 9507-9508).

And the specific challenges associated with Monte Carlo analysis for resource planning and in particular for matters to be reviewed in a regulatory forum were noted by Mr. Bowman:

> MR. PATRICK BOWMAN: … I know some people have talked about Monte Carlo modelling. The Monte Carlo approaches have some real benefits. They also come with some downsides. We saw Monte Carlo

> modelling trying to be done to Hydro's system by the Professors Kubursi and Magee that the Board retained in the 2010 GRA, if I recall correctly.
>
> And I think it may have highlighted some of the reasons why that may be a inferior system for modelling Hydro's approach, one (1) of the main ones being Hydro's system is very complicated. It has lots of overlapping variables. Monte Carlo simulations have to be carefully designed if they're going to deal with things that have dependent probabilities. They're not all independent.
>
> And the other downside, especially for a regulatory type forum, is it's very hard to decipher and provide the evidentiary background and poke and prod and dig through Monte Carlo simulations. So, for example, when the professors did Monte Carlo simulations, they would have modelled Hydro's water rentals as one (1) variable. They also modelled Hydro's exports as another variable.
>
> And the Monte -- and we couldn't get into the Monte Carlo to see whether they had design scenarios that had high water rentals and low exports or low flows or something. Like, you -- it's very hard to get back in. You have how many thousands of lines of code if it's even retained. Often the system just dumps it, and all it shows you is the final results (Tr: 10105 – 10106).

Mr. Bowman also addressed this matter under cross-examination from Hydro:

> MS. MARLA BOYD: Would you agree that in contrast to Monte Carlo simulation, that probabilistic scenario analysis or probability tree analysis can rely on fewer runs typically to get an equivalent level of accuracy?
>
> MR. PATRICK BOWMAN: It can rely on fewer runs, I would say, to get an acceptable level of accuracy. I'm not sure if it would be equivalent, but for -- certainly, to get to acceptable.
>
> …
>
> MS. MARLA BOYD: Would you agree that probabilistic scenario analysis often provides more transparency than Monte Carlo simulations?
>
> MR. PATRICK BOWMAN: Yes, absolutely, and especially in a regulatory forum. If -- it would be different if you were running a university department or something where a bunch of people could gather around a computer monitor and rerun scenarios and discuss them or something of that nature.
>
> But if you've got a file -- some evidence and people need to be able to cross-examine you on it, Monte Carlo simulation is a very difficult way to

> find out if you've done everything correctly, to be tested, to have a proper cross-examination and evidence (Tr: 10256-10258).

MIPUG does not recommend that Hydro be required to pursue a Monte Carlo form of analysis for its resource planning framework. If such an approach can be readily adopted, then it may be suitable so long as the regulatory review challenges can be resolved[19]. If that is not possible, the scenario approach used by Hydro remains a reasonable planning approach.

[19] For example, it may be possible to continue to run scenario analysis as the primary analytical tool, but supplement this analysis with Monte Carlo work showing how well the scenario analysis conforms and explores the outer bounds of the Monte Carlo scenarios.

6) Has Manitoba Hydro Applied Proper Utility Economic and Financial Analysis to the NFAT?

In general, MIPUG finds the work of Hydro in preparing its economic and financial models to be robust and accurate. With limited exceptions it appears the models represent a reasonable basis for analysis of the proposals. It is important to note the limitations that arise in the first instance from use of models:

> MR. PELINO COLAIACOVO: …The -- the purpose of modelling, and of indicative financial modelling as one (1) kind of modelling, is to provide insight into matters that a decision maker has to make judgments about.
>
> Models are never conclusion. Models are not reality. And, you know, the best you can do with a well-designed model is to bring issues to light, which is what we were trying to do with the comparative modelling and analysis that we did for the report.
>
> But in every model you make assumptions, you make projections. You rely on forecasts that other people have provided to you, and they may or may not be right. There is a range of possibility that everyone assumes and -- when they're doing their own work, and all of those ranges accumulate as you put them together to make a model. It -- it's the difference between accuracy and precision.
>
> You know, indicative financial models -- the good ones, strive to be accurate, but the – the most accurate prediction of the future is the one that has a range from zero percent to a hundred percent, because you know the future will fall somewhere between zero and a hundred. The more precise you become – you know, if you say that the future is going to be 52 percent, the more likely it is that you're inaccurate.
>
> So there's a balance that's required when you're using models to make the models precise enough to give you useful information in making your judgments, but not fool yourself into thinking that it's anything more than that. They're just analytical tools (Tr: 7419 – 7420).

There was considerable discussion about various aspects of the analysis conducted. MIPUG's specific views are as follows:

Duration of analysis: The use of a long-term horizon for analysis (78 years for economics and 50 years for financial) is appropriate for considering overall which plans should be pursued. However, for assessing impacts on ratepayers (which is a priority consideration in making NFAT decisions) the rate impacts over time horizons from the very short-term through to the full forecast of 50 to 78 years is required.

Use of NPVs: The economic analysis of Net Present Value is an appropriate means for comparing the plans. However, NPVs are not the only relevant consideration. This is because two different plans with vastly different required levels of investment can yield the same NPV, but the effective return on investment and peak debt levels are very different. Committing a billion dollars to secure $100 million in NPV is different than committing ten billion dollars for the same $100 million NPV. In this hearing, however, the scale of investment and maximum debt levels are similar for both the Need-based Plans and the Opportunity-based plans with the exception of Plans that include Conawapa[20]:

- Plan 2 (Keeyask 2023) is a Need-based plan with maximum net debt at $20.0 billion.
- Plan 5 (Keeyask 2019, 750 MW) is an Opportunity-based plan with maximum net debt at $20.6 billion.
- Plans that contain Conawapa (including the PDP) however show maximum net debt at $29.6 billion under the latest assumptions.

Treatment of "Common Costs": Hydro's initial economic analysis was reliable for reference conditions (REF-REF-REF) but had a significant issue with scenarios that varied the Discount Rate from reference conditions, which led to Mr. Bowman providing Appendix B to his Pre-Filed Testimony[21] ("Economic Analysis Critique"). Hydro provided extensive rebuttal to this critique (including a supplementary analysis by Dr. Borison in Schedule 3 to Exhibit MH-85) but ultimately adopted one of the key recommendations in a "refined version of the analysis" (Tr: 2171) noting "our staff had found this problem, as well" (Tr: 2545). The updated treatment of capital costs resolves much of the MIPUG concern with Hydro's quilt analysis. This is of little benefit however, as Hydro has been unable to provide any version of the quilt that actually adopts the 2013 updated assumptions, as noted below

[20] Exhibit MH-150.
[21] Exhibit MIPUG-9-2, Revised February 28, 2014.

Expected Values: The inability to produce a 2013 quilt means that there is no way to update the "Expected Values". In particular, Dr. Borison noted that the Expected Value is "probably most important or most common risk output" (Tr: 1376). Mr. Bowman noted the issue that this poses for the analysis:

> MR. PATRICK BOWMAN: The big concern that we have is that the expected values of the first time around were considerably lower than the ref/ref/ref values. More so on the economic side than on the financial side, but they were considerably lower.
>
> And based on the information that Hydro's filed, we can't update the expected values for the 2013 assumptions. But I think we want to be really careful about assuming that the expected values for the 2013 assumptions will be similarly lower than the ref/ref/refs for the 2013 assumptions, primarily because of the only data available to me, which is in Appendix 9.3, which said that the 2013 assumptions with respect to export prices move the reference value up 7 percent, move the high value down 7 percent, but move the low value up 41 percent.
>
> And I don't -- haven't seen those prices, so you'll know better than me. But I think there's a likelihood that the expected value and ref values would have tightened as a result of that, because the very low export price scenarios which we, to the best of my knowledge, included in the 2012 scenarios, probably should have substantially improved by way of that adjustment (Tr: 10173-10174).

This is an unfortunate inferiority with the current hearing record. There are no updated Expected Values for the 2013 assumptions on export price. The quilt has been updated for the expected risk range of capital costs (Exhibit MH-104-8). As noted by Mr. Bowman the inference is the Expected Values for export prices have likely improved since the initial quilt was prepared, but expected values are likely to remain somewhat lower than the NPV for REF-REF-REF, as noted by Hydro's panel: "I think that there would be a difference between the ref/ref/ref and the expected value, and the expected value would be in some way lower" (Tr: 2620).

Economic Discount Rates: Hydro's use of a Weighted Average Cost of Capital (WACC) to the utility is appropriate for economic analysis. Hydro also presented their concept of an "ROE embedded in WACC"[22] which purports to represent that by using a WACC, Hydro has effectively failed to show how much return on equity is already

[22] Exhibit MH-171 (Revised).

accounted for when calculating the economic NPVs. Mr. Bowman addressed this concept indicating it could be informative, but should not be the primary consideration:

> MR. PATRICK BOWMAN: … this is a new concept that was introduced rather late in the process by Manitoba Hydro. It's mostly just an analytic revision to the way that they present the economics. The premise is that they're reflecting a weighted average cost of capital of a hundred percent debt, and it's not entirely unreasonable to use that premise, because if you're trying to reflect a weighted average cost of capital, the cost of capital financing these projects is primarily going to be a hundred percent debt for a heck of a long time. They're no -- there's no equity investors. No one's putting up money from the outset.
>
> So from that perspective, it's not that it should be dismissed right away. I wouldn't encourage anyone to use it as their primary test, or to not make the distinction, but I don't think that's what Hydro has done. They've added another bar. They've said it's informative, and I think it is informative.
>
> I think part of the distraction is it's really poorly named. It's not reflecting a return on equity. That -- for that, you need to really turn to the financials (Tr: 10129).

One of the main issues with the embedded equity NPV is that it effectively is calculating the NPV of a plan looking only to the need to finance the underlying debt. Conceptually, we know that larger plans require other levels of returns – whether that is for First Nation benefit sharing, setting aside reserves, or helping build to a debt:equity target. All of those other considerations cannot be achieved with a plan that is solely (barely) able to repay its debt over its life, which is what a 4.65% discount rate effectively represents.

Discounting Customer Rates/Bills: On the matter of discount rates used for analyzing ratepayer impacts (rates or bills paid) as part of the financial analysis, MIPUG strongly disagrees with Hydro's rigid application of a 1.86% real discount rate (3.80% nominal)[23]. The MIPUG also notes that at the time of the Wuskwatim NFAT, Hydro used a much higher 8.2% nominal discount rate[24] for discounting the effects on customer rates. The new very low 1.86% real discount rate was justified by Hydro on two key analytic rationales: first, that the cost of debt and equity and setting aside reserves is already included in the revenue requirement/rates, so in discounting the power rates paid there should be no further consideration of equity and debt costs; and, second, that a

[23] As calculated in PUB/MH I-149a (Revised), page 3 of 26.
[24] Tr: 3234; Exhibit MIPUG-20-5 page 197.

commercial type discount rate (such as Hydro applies in the economic analysis) is not appropriate as the Plans represent public infrastructure and as such a lower social time preference rate[25] is the appropriate metric, as follows:

> MR. DARREN RAINKIE: So our concern is that in this project, you're -- if by using a higher discount rate, you're number 1), double counting, because you're discounting a revenue requirement, you're not discounting expenses and revenues. And as well, what you're doing is suggesting from a intergenerational equity perspective that we're really not that worried about customers, you know, anywhere past year 10 or 20. We're really concentrated on today's customers, but we're discounting heavily, almost to nothing, any benefits the future customers may obtain from this.
>
> And that's our change in perspective that we talked about today from the Wuskwatim filing is that in preparation of this filing, we looked at, What are we doing? What's the purpose of this? Especially since in the Preferred Development Plan, the last asset doesn't go into service until year 20 of the forecast. So if you use a high discount rate, by year 20, you're not really valuing anything after the asset has just gone into service.
>
> So that's why I keep saying, Let's keep our focus on, What are we doing? What's the -- we keep slipping back into, you know, technical theory, but I think we have to keep asking ourselves, What is the purpose of the financial analysis in the first place?
>
> …
>
> In our mind, I -- I've seen discount rates that go as high as 10 percent. In our mind, the range of appropriate discount rates are -- is much smaller. I think we had on that rebuttal page, I think, 1 1/2 to 3 percent. Sorry, the page that you had up just a -- a few minutes ago. I've seen a range as high as 10 percent, and I think the implications of a -- of a 10 percent discount rate is it's almost like we're looking at this as a -- as a -- a venture capitalist kind of a, you know, a -- a look at the world that a -- a private investor or something that would need to either return their capital very quickly, or is looking for an appreciation of the assets so that it could be sold very quickly.
>
> We're investing in public infrastructure for the long haul, and we think that specifying a very high discount rate, what it's doing is essentially throwing future generations of customers under the bus (Tr: 3457-3460).

[25] Tr: 2944.

The concern for MIPUG members is that (a) Hydro is in error about suggesting that a customer WACC-based discount rate is double counting, and (b) this type of analysis is failing to reflect that the economic transaction for customers is via the rates they pay – it is not a social impact of regulation. Explained further:

a. On the first point, Hydro was correct in the Wuskwatim hearing when it applied a discount rate to customer impacts that was fundamentally based on the cost of committing capital to an investment. This represents the capital committed by customers similar to how Hydro's economic analysis represents the capital committed by Hydro. Applying a WACC-based discount rate to the customer, who is downstream of Hydro in the transaction, is no more double counting than applying a WACC-based discount rate to Hydro who is downstream of the construction firm building Keeyask (who has already applied their own costs of capital to their construction costs). Each party has their own capital. Each party has their own transaction. Each party faces a trade-off of committing capital compared to other viable comparable options.

b. On the second point, for the customers, the higher rates paid to secure a development is their investment (and is consistent with Hydro's messaging, that "It's our generation's turn to invest"[26]). The discount rate applied to the analysis is effectively representing the customer's return on their investment. It is expected that there will be different perspectives among Hydro's customers, but for many businesses, or low income residences for example, a higher required discount rate would be expected (as their alternative use of funds is unlikely to be investing in instruments that provide a low rate of return – such as Treasury Bills). A social discount rate is typically used to analyze the impacts of policies, regulations, tax supported infrastructure, including likely those referenced by Dr. Borison[27], and measures the impacts on society in general. It is fundamentally different than a business case investment by a customer or customers of Hydro, as noted by Mr. Bowman:

> MR. ANTOINE HACAULT: Thank you. Now, could you deal with slide 29, being the discount rate views that have been expressed in this hearing?

[26] E.g., See Exhibit MIPUG-20-5, page 43-44.

[27] Dr. Borison provided an example of a "regulatory" use of hyperbolic discounting referenced back to the UK Treasury at Tr: 2535.

> MR. PATRICK BOWMAN: Yes. I -- we made some comments about Hydro's very low discount rate they've suggested to be using for customer benefits. I didn't use that discount rate. We did use it as our low scenario just to -- so that the information was available. We did not use it as our reference or our high.
>
> I think it's -- based on -- in part on the literature Hydro shared, it's -- using a rate that is based on a real return on risk-free savings to the customer has some analytical basis. It probably is not appropriate in this instance where customers are paying higher bills at one (1) point in time in order to have lower bills at another point in time. You're not trying to capture a social cost there. You're trying to capture effectively a business case for the customer, is what you ought to be doing. It's exactly what Hydro did in the Wuskwatim hearing; they used a discount rate of a higher range, around the 5 percent type of level. It's what we've recommended here, and I don't think the one point eight-six (1.86) -- I don't think the analysis starts and ends with the 1.86 percent rate.
>
> And some of the arguments they've been putting forward to it that using anything higher would double-cost -- or double-count the equity returns or that it throws future customers under the bus or that it -- the entire -- that you'd be -- I guess it's the same double counting point, that using - - we've already included a cost of equity and we've already included risk in our scenario, so we should go to this very, very low real rate because it's risk free. It's the same as what the world is doing by investing in T-bills. And I don't think that's a relevant measure when you're asking businesses, residents, all sorts of people to -- that it's -- what do they call it -- our turn to invest when you're asking for that type of participation in the plan (Tr: 10126-10127).

Further, a single ratepayer use of a discount rate (as advocated by Hydro) is unlikely to capture the full picture of ratepayer experience, as noted by Mr. Colaiacovo:

> MR. PELINO COLAIACOVO: … [W]e believe it's appropriate to do these tests at different costs of capital because -- sorry, at different discount rates because the stakeholders that are interested in Manitoba Hydro's decision making are themselves very different and have different characteristics. We made the point elsewhere that for investors the discount -- the appropriate discount rate to use in the net present value analysis is the investor's cost of capital, the cost of capital that investors are facing when they are making an investment decision in a project.
>
> But in Manitoba Hydro's case, there is no investor that's putting equity into a new project. Manitoba Hydro gets its revenue -- gets its capital either from retained earnings from ratepayers or from government-guaranteed debt. And on that basis, it's relevant, we believe, to look at the

> cashflows that ratepayers are going to be responsible for and the cashflows that the government is going to be interested in, and consider those across a range of possible discount rates, because some ratepayers will have a high cost of money and some ratepayers will have lower cost of money.
>
> And would those ratepayers react differently to these different plans? One way to test that is to use a range of different discount rates and to understand, you know, if a ratepayer had a higher cost of money, they would like plan A versus plan B, or vice versa (Tr: 7456 – 7457).

At its core, however, Mr. Bowman addressed the conclusion from his perspective that in some cases this debate could be very material to the outcome of a decision, while in the current case much less turns on this debate:

> MR. ANTOINE HACAULT: What's the advantage or disadvantage of doing what you did, sir, of testing the high and the low around the 5.05 percent? What insight does that give us?
>
> MR. PATRICK BOWMAN: Well, it's only because there's lots of perspectives, even among the literature that is -- was distributed by Hydro. There's lots of different perspectives, and so it's worthwhile knowing whether this -- whether any of your decisions turn on this issue or not.
>
> And frankly, even if we look at Hydro's 1.86 percent real, which is part of the reason I call this a tempest in a teapot, we wouldn't come to any different conclusion in any event than the five point-o-five (5.05) we used, mostly because it takes an extraordinarily long period of time for the rates -- the higher rates that are paid to ever turn around, even under a 1.86 percent real (Tr: 10127-10128).

7) Is There a Need for the PDP?

Manitoba Hydro presented the need for the PDP as follows:

> MR. SCOTT THOMSON: Now, as I've already mentioned, the fundamental driver of the NFAT analysis is the increasing electricity demand in Manitoba. We can, and likely will, debate the pace of this growth and debate different ways to slow it through energy conservation or demand-side management initiatives.
>
> However, what is crystal clear in my view is that: A) the Manitob -- that Manitoba Hydro has an obligation to meet the province's future demand for electricity, and B) new supply will be required sooner rather than later to meet that obligation
>
> As I noted a minute ago, our statutory mandate contemplates exports on appropriate terms. As I'll discuss later, exports have been a major reason why Manitoba Hydro's rates remain so low relative to many other jurisdictions. Revenues from exports help to offset costs for domestic customers.
>
> While our need is associated with domestic load, it is appropriate and important, in my view, to look at the potential for export revenues to be enhanced. These opportunities exist right now and they're real. Manitoba Hydro already has in place significant commitments from the US utilities to purchase new power supplies. And of course, all of our resource planning is done with an eye to the principles of sustainable development (Tr: 78 – 79).

The new DSM plans have substantially pushed domestic need past the initial expectations. From Exhibit MH-192 the most likely need date at present is 2024 (requiring a decision to proceed with Keeyask by 2019, or a commitment to gas by up to 2 years later[28]). This varies under different scenarios provided in MH-95, depending on the level of future load reductions new dependable energy may not needed until sometime between 2027/28 and 2033/34[29].

> MR: PATRICK BOWMAN: … Mr. Rainkie used the example of the rent out a basement in your house, that this is -- these are opportunities to

[28] Per MIPUG/MH I-10(a) the decision date to commit to Keeyask is approximately 5 ½ years in advance of the needed in service date. For gas, this commitment time frame is 3-5 years.

[29] MH-95 slide 4 – 2027/28 is the scenario with DSM Level 2 with pipeline load, 2033/34 is with DSM Level 3 and no pipeline load.

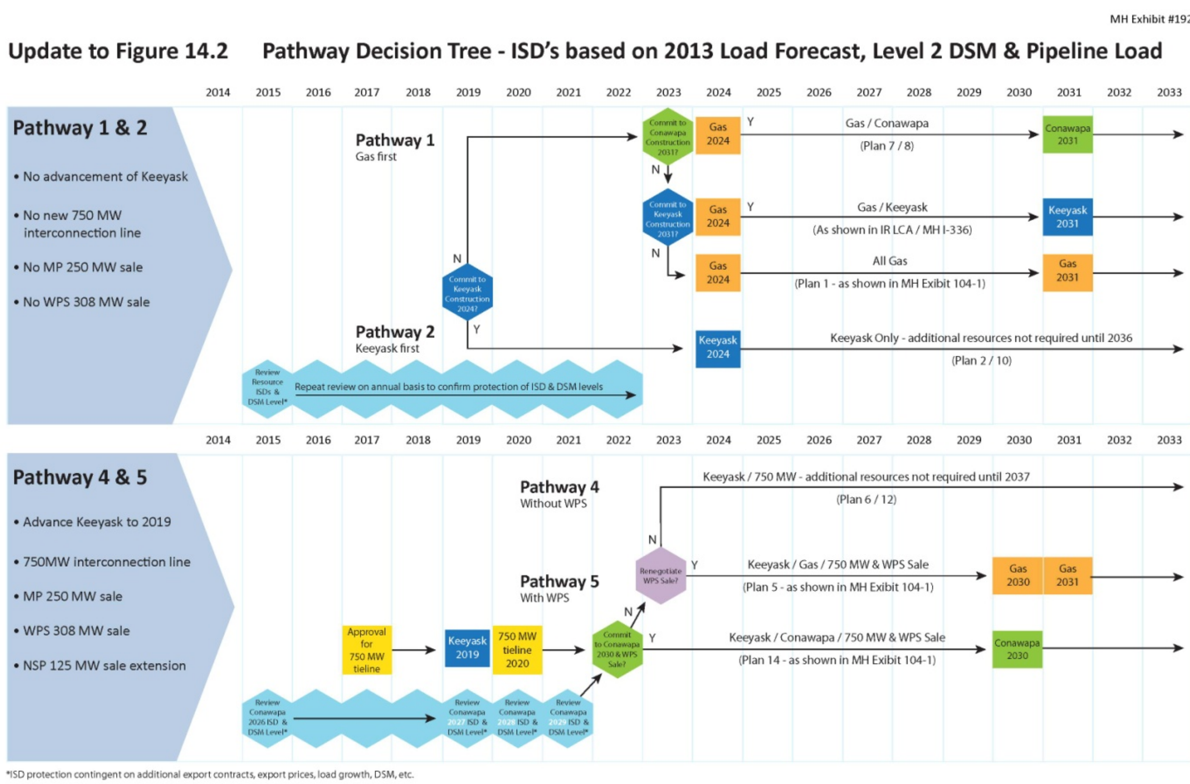
> build a little more than you need now, advance them, make some revenue off of them, and you'll grow into them.
>
> And it's an example -- it's actually the exact analogy I've sometimes used to people to explain how Manitoba Hydro does advance its plants and how it builds things like Wuskwatim.
>
> I didn't think it held up very well in this hearing because of the scale of things we're dealing with and the timeframes of things we're dealing with.
>
> Keeyask being advanced three (3) or four (4) years as it originally started, it might work okay, but even then, you're bring on 695 megawatts. Your need date is not because you need 695 megawatts, it's because you need the first megawatt for your own domestic supply.
>
> It's still a long time to grow into that plant, but the three (3) or four (4) years, the basement model is, you know, the bedroom-in-the-basement model is not a bad example.
>
> We're now talking Keeyask advancement could be six (6) to nine (9) years, depends on some pipeline loads in part, and I would assert some other industrial loads that people need to pay attention to as well, as well as other load risks.
>
> It's a little more than a basement bedroom, might be a suite. We might be verging on a duplex.
>
> Conawapa is something different entirely. Conawapa, in the context of Plan 14 and its need concept is a lot more like investing in an apartment block across town, is the phrase I've used.
>
> It's tangentially related to housing, but it's a long time before you grow into needing that one for your basic supply, and so I think it's important to be able to think about that differently (Tr: 10056 – 10058).

As it’s currently defined, Manitoba load does not need the PDP. Manitoba load does not need to advance Keeyask or to build a 750 MW line.

8) Is the PDP Concept Superior to Potential Alternatives?

The PDP can be understood in two different contexts. One is a rigid commitment to Keeyask 2019, a 750 MW line, the new export contracts (plus additional contracts under discussion) added North-South transmission, and Conawapa for an In-Service Date (ISD) as soon as (ideally) 2026 but potentially as late as 2031. In short, this concept of the PDP is a firm path the entire way through Exhibit MH-192, shown as the bottom row:

Exhibit MH-192 Pathway Decision Tree



To the extent this future fixed locked-in sequence of events is the PDP, it is inferior to other options and should not be approved to proceed today.

The better understanding of the PDP is that it encompasses the entire bottom half of Exhibit MH-192. It involves only a limited set of decisions today, and includes a large range of possible future paths in terms of sequence, in-service dates, and including whether to build Conawapa at any time in the next few decades. It is important to understand the PDP in this context, as expressed by Mr. Colaiacovo:

> MR PELINO COLAIACOVO: The burden on Keeyask is much higher because of all of the investment that's been made in it, so a choice not to proceed with Keeyask should be done only for very strong reasons. Whereas on Conawapa, because of the speculative nature of Conawapa as of today, and I think everyone – every reasonable and rational outside observer would believe that there is lots of questions around Conawapa, would have a very, very different impact (Tr: 7441-7442).

The specific economics in support of the PDP (including pathways that ultimately terminate in Plan 5, 6, 12, and 14) are set out in later sections of this argument. The conceptual framework and support for the PDP is addressed below.

Conceptually, the parts of the PDP that need to be decided today, the 750 MW Interconnection and advancing Keeyask, bring benefits compared to potential alternatives:

> MR. PATRICK BOWMAN: … [T]here is an extremely good record with hydro generation over the long term in Canada. It's an inherent characteristic of hydro. It's also been done well in most of the places in Canada that I've ever seen. And even more important to that is if you're -- on a system like Manitoba, interconnections are absolutely critical if you want to be a hydro-based utility. If I'm dealing in places that don't have good interconnections or don't have any interconnections, like Newfoundland or Yukon or Northwest Territories, or almost any anywhere that it faces the situation in Canada. You're going to have a very hard time economically justifying pushing your system to more than, you know -- 60 percent was traditionally a ratio we talked about with higher oil prices, maybe 70, 80 percent hydro without complementing it substantially with a thermal-based generation.
>
> And Newfoundland has Holyrood oil plant; Yukon has diesels that they're working into converting to LNG; Yellowknife's always had diesels. And the reason is because of the nature of hydro plants that I believe Mr. Cormie's explained quite well.
>
> …
>
> But hydro plants produce two (2) products, one (1) of which is good for domestic service, and one which is effectively not. And if you want to be able to build a hydro plant, you need the economics where you can take the dependable product and use it for your own domestic service. And that opportunity product -- the second product, has to either be able to be of value to you or of value to an export market. If you need it to be a value to you, such as they do in Newfoundland, you have to be able to offset that against a fuel cost (Tr: 10064 – 10065).

Further, the PDP concept is also well aligned with the current configuration of the Hydro system:

> MR. PELINO COLAIACOVO: To use La Capra's language, given that Manitoba is building Bipole III, and Bipole III has reliability benefits for the province, but it also creates additional transfer capacity from north to south, which would not otherwise be there: trans -- electricity transfer capacity.
>
> If you are going to optimize the Province's system and you had this additional transfer capacity, it's entirely appropriate and legitimate to consider whether you can opt -- whether you can optimize the output of the system by building additional northern Manitoba hydroelectric facilities. Gas -- or the All Gas option doesn't actually make use of that transfer ability.
>
> So in that sense, you know, it's not optimal considering the entire investment of Manitoba Hydro which comes out in all of the analysis, which is why building Keeyask and taking advantage of the additional transfer capacity of Bipole appears to be at least equally as attractive as All Gas, if not more. It's a consequence of the decision that was made previously and it makes sense in that context.
>
> Again, it's positional thinking. We are where we are. Bipole -- the Bipole III decision was made, the investment is going ahead, therefore, when you do the numbers it appears that building Keeyask makes sense. Had we had this discussion three (3) years ago before the Bipole decision was made, maybe there would have been a different conclusion. But it's not three (3) years ago; it's today (Tr: 7398 – 7399).

The first stages of the PDP in the form of Keeyask advancement and the 750 MW line also must be viewed in light of their current status and progress:

> MR. PELINO COLAIACOVO: Commercial negotiations are just that; they're negotiations between independent parties. And while all in -- all of us external experts and all Intervenors and commentators and analysts external to the situation, to the transactions between Manitoba Hydro and its -- and its partners, can question whether those particular transactions may or may not be the best transactions which could have been negotiated, the reality is those are the contracts and arrangements that have been negotiated. And they can either be accepted or rejected. And it shouldn't be presumed that amendment can be easily or achieved at all.
>
> If that package of arrangements of Keeyask, and the intertie, and the export agreements is cancelled; if, for example, amendments were suggested -- were not accepted and the parties walked away from the

> table, there are significant cost consequences that must be borne. Not only the $1.4 billion of expenditures as of the end of June, but there is also an issue of the commercial reputation of Manitoba Hydro and its ability to do business in the future.
>
> It has been working for a number of years on the Keeyask project, the intertie project, and the export contracts. It's been working with a wide variety of parties who have come to the table in good faith and negotiated these arrangements on the assumption that there was an ability to actually execute on them.
>
> That is not determinative. Deals fail all the time in the world. But when deals fail there are consequences to deal failure. And those are -- consequences are not always easily calculated in dollar terms. There is a loss of reputation, and there is a loss of the ability to do business. None of the alternative plans of the many different alternative plans that have been put before the panel address that issue. There is a cost consequence in terms of the writing off of some costs, but there is no additional cost burden that is understood to be related to the commercial consequences of the collapse and cancellation of the plans.
>
> So from our perspective, looking at Keeyask and the 750 megawatt intertie and the export contracts through a commercial lens, the -- you know, we look to almost a cliche, but it's very much relevant in a commercial context. These are actually negotiated commercial agreements. This a bird in the hand. And if they are going to be rejected in favour of an alternative, there is a very high burden on alternatives to be demonstrated to be significantly superior to the real package and the real opportunity that is before us in completing the Keeyask construction and in the 750 megawatt intertie and all the associated export contracts.
>
> It's not good enough for an alternative to be mathematically or technically or theoretically equivalent. There has -- it has to be demonstrated to be superior for it to be commercially interesting as compared to a real, actionable opportunity. And by all of the information that we've prov -- been provided as part of this process and in our position as advisors in this process, as independent experts, we have seen that, you know, this is a real commercial, viable opportunity and is in fact on the verge of, you know, commencing construction, potentially, if the final approvals are given to it (Tr: 7254 – 7257).

Specifically for MIPUG, the current interconnection and hydro system has generally proven to support the reliability, stability and long-term benefits important to industrials.

> MR. BILL TURNER: When it comes to rates both Hydro developments and transmission connections to other jurisdiction typically fit with industry's needs. This is because industry has to be concerned about the

> long-term rates and because it is important that power rates are stable. Both of these things are critical to companies that collectively invest billions in plants in Manitoba.
>
> Industry also cares about reliability. And hydro provinces with interconnections have typically proven to perform well in this measure. Also important to industry is that sufficient power is available for growth and expansions (Tr: 7205).

For Conawapa, however, as part of the Preferred Development Plan, nothing produced on the record makes a concrete case for it being a benefit to ratepayers today:

> MR. PELINO COLAIACOVO: When we turn to look at Conawapa, it's a very, very different situation. Conawapa has been a known and understood option for many, many years. It's been the subject of review processes in the past. At different times over the past twenty-five (25) years, it has been the next project about to be done, and then no longer. It is a development opportunity. It's a very significant development opportunity.
>
> In Manitoba Hydro's submission, they provided information on more than a dozen different sites across the province that are potential opportunities for new hydro power, and for a wide variety of reasons, they consider Conawapa to be one of the better ones. That's common knowledge.
>
> But just because something is a development opportunity, it doesn't mean that it should be developed or that it should be developed right now. It's an available option, and that option will not go away. The only question is: Should additional money be spent on that option, and, you know, should there be support for pursuit of Conawapa as the primary option for Manitoba Hydro?
>
> The -- you know, in contradistinction to our view of Keeyask and the 750 megawatt intertie, with respect to Conawapa, the burden is very much, we think, on Manitoba Hydro and on the proponents of the Conawapa process to justify that it is worth spending the next dollar on, that it is worth keeping on the table, that, you know, considerable resources should be focused on that opportunity as opposed to other opportunities which are also available to Manitoba Hydro and to the province as a whole (Tr: 7257 – 7258).

With respect to the potential to focus only on Manitoba's strict resource requirements, as set out in the top half of Exhibit MH-192, such a needs-based plan does not provide the same future flexibility and benefits as an opportunity-based plan (represented by the bottom half of Exhibit MH-192):

> MR. PATRICK BOWMAN: It's [The needs-based pathway] not as flexible for load growth risk. It's certainly leaves the opportunity of the 750 megawatt line on the table as it exists now.
>
> It -- you know, it may come back, but for now, we would be walking away from that option, and I think it has a fairly significant potential for losing some of the social and government benefits that go with the Preferred Development Plan, while picking up some others that I don't know that are well quantified (Tr: 10054).

Additionally, the Opportunity-based plans optimize the existing system from the perspective of the commitment that was previously made to develop the north and focus on development of the Nelson River:

> MR. PATRICK BOWMAN: … [I]n the context of a planning needed to make the original commitments to the projects, to the Nelson River and the like, that were highlighted this morning and highlighted in some other presentations you've seen.
>
> It's not my intent here to suggest that I am spending any time on overall environmental impacts. But just in a planning context, there has -- the projects in the plan as proposed is part of something that's been underway for fifty (50) years. It doesn't mean it's the right thing to do. It could be a sunk cost fallacy in respect of environmental impacts.
>
> But it is worth noting this is not striking off in a new direction for Manitoba. And some of the foundational and unfortunate environmental effects that were needed to make these projects occur are -- exist and are happening today. And, in that regard, if they're effects that were incurred with an assumption of five, (5), six (6), 7000 megawatts of downstream generation and much of that is going unused, it's -- it just notes of how it fits into an overall planning context (Tr: 10072 – 10073).

In addition, the development of a next tranche of hydro generation and international transmission is in keeping with Hydro's strengths and is complementary to the markets where it transacts:

> MR. PATRICK BOWMAN: I think the next point on interconnections is not always the focus of peoples' comments, but there is a fair number of commenters who are suggesting that Manitoba Hydro has -- is moving in a direction of putting all its eggs in one (1) basket. It's a phrase that's used.
>
> In an overall planning context, I think it's a valid comment if you're stuck with running a system on an island like we see in Newfoundland for now.

> The other option is to not be an island, is to build more transmission and complement other peoples' diversity. And in that regard, if there's somebody who's got a better opportunity to build wind, they should build the wind.
>
> If there's someone with a better opportunity to build the thermal, there are less options and is stuck with the thermal, then they can do that. Manitoba brings to the -- this part of the world some options in respect to hydro that other people don't have. So is it diversity?
>
> Well, your own entity is certainly committed to one (1) type of resource heavily, and it may be a -- may view it as a good one or a bad one. But I wouldn't tend to criticize it on diversity. I think the transmissions is a component of the diversity. And getting yourself to be not islanded, but part of a bigger system helps address that.
>
> And, of course, the other thing is that if you're able to bring on bigger plants, you certainly have more flexibility to address unexpected load requirements, so (Tr: 10073 – 10074).

Based on the alternatives that are available to be pursued, the initial components of the Preferred Development Plan, including advancing Keeyask to 2019 and the 750 MW Interconnection, are conceptually superior to plans restricted to only fulfilling Manitoba's need as of the date new resources are required.

9) What are the Economic and Rate Implications of the PDP as Proposed?

The latest summary of the economic analysis is provided in Exhibit MH-171 (Revised). Without extensively repeating the details contained in that exhibit, the situation today appears to be best focused on Level 2 DSM with Pipeline, with information from Level 2 DSM (lower net load) and Base or Level 1 DSM (less achievement of DSM; higher net load) as being informative in regard to risk that Level 2 DSM may not be achieved, as follows:

> MS. MARLA BOYD: And in considering forecasting of net load, by which I mean load net of DSM, throughout the course of this hearing Hydro's provided information on three (3) levels of DSM and is in the process of pursuing programs which approximate Level 2 DSM.
>
> Is that your understanding?
>
> MR. PATRICK BOWMAN: My understanding is Hydro's filed three (3) levels of DSM and that DSM Level 2 is the best of the bunch. I only -- I haven't spent as much time with the latest green covered DSM plan to make sure that -- whether that is Level 2 or the like. And I have cautions about whether all of the measures in there can be achieved.
>
> I've sat through too many hearings before this Board about inverted rates and conservation rates and debates about them to think that that's a nice, low cost way of saving a lot of power.
>
> There are other flip sides to that argument that have been persuasive in the past. So I'm only saying will Level 2 be achieved if it involves conservation rates, if it involves industrial co-generation? I think it's probably early days to know that those can be put into place.
>
> MS. MARLA BOYD: You sort of anticipated my next question, that there would be uncertainty in forecasting load and net load, correct?
>
> MR. PATRICK BOWMAN: Yes, and DSM, yes.
>
> MS. MARLA BOYD: And would you consider it prudent then for Manitoba Hydro to undertake sensitivities with higher loads in its long-term resource planning in recognition of that uncertainty?
>
> MR. PATRICK BOWMAN: Oh, absolutely. As a matter of fact, that was one (1) of my recommendations.

> MS. MARLA BOYD: And would you also consider it prudent on the part of Manitoba Hydro to recognize uncertainty with respect to achieving dramatically higher levels of DSM in -- for long-term resource planning?
>
> MR. PATRICK BOWMAN: You use the word 'dramatically'. I think if someone wants to put in dramatically higher levels of DSM, you would need to somehow represent that they're dramatic. And I assume you're using the word 'dramatic' to mean -- to be redundant with saying there's some uncertainties associated with them. I don't -- I can't say for sure whether the DSM plans that Hydro has proposed are dramatic. I can tell you a few of the measures that are in there that are significant components of DSM Level 2, I would encourage people to view with some uncertainty (Tr: 10260-10262).

With that introduction, the NPV values in Exhibit MH-171 (Revised) must be viewed in light of the scale of Hydro's system. In particular, at a consistent discount rate with the economic assumptions, the present value of rates to be paid by Manitobans over the next 50 years is approximately $40 billion[30]. Against this backdrop, NPV benefits of less than $400 million (over 78 years) represent less than 1% overall system benefits compared to the alternatives. In short, under the assumptions that the government charges remain as per the NFAT filing, none of the plans show robust economics.

By far the best economic profile across the various load levels is for Plan 5. This Plan is part of the overall PDP pathway in terms of being part of the bottom half of Exhibit MH-192. It involves advancing Keeyask to 2019, committing to the MP 250 MW sale and the 750 MW transmission, and attempting to secure the WPS 308 MW sale despite not proceeding with Conawapa (The evidence is if Conawapa does not proceed WPS can terminate the 308 MW sale, but can also choose not to terminate). Plan 5 also includes gas, if needed for domestic load purposes after Keeyask. The best evidence, however, is that even if WPS elects to terminate, the economic profile is not materially damaged (per 2013 assumptions, the NPV of Plan 6 – No WPS – is only slightly below Plan 5[31], and per 2012 assumptions Plan 6 is actually preferred to Plan 5 albeit with a slightly larger P90/P10 "risk/reward" range[32]).

Plan 5 also shows a surprisingly high degree of robustness across a wide range of load conditions. The extreme analysis is provided in Exhibit MH-156 which notes that even with no load growth whatsoever after 2023/24, Plan 5 still shows an NPV of

[30] MIPUG-9-2, Pre-Filed Testimony of P. Bowman, Revised February 28, 2014, page C-24.
[31] Exhibit MH-171 (Revised).
[32] Exhibit MH-104-8.

approximately $400 million, on the same order as the other load scenarios shown in Exhibit MH-171 (Revised).

In terms of rate impacts, Hydro has provided three alternative rate design scenarios which are further discussed below. Focusing on Plan 5 rates in comparison to Plan 1 (All Gas) and Plan 14 (the full PDP)[33]:

- All Rate Design Methodologies show Plan 5 to have a long-term rate impact (2061/62) that is higher than Plan 14, and lower than Plan 1. As Plan 5 retains the ability to proceed with Conawapa if future conditions so support, this metric is not considered to be determinative to selecting a plan.

- Under all rate design approaches, Plan 5 has a materially lower short-term rate impact to 2031/32 than Plan 14 (on the order of 20-30% lower)[34].

- Only one of the methodologies shows Plan 5 having a materially higher short-term rate impact than Plan 1. This is the “Main Submission” approach, which shows cumulative rate impacts to 2031/32 for Plan 5 at 94% versus Plan 1 at 82%. However, the main rationale for this difference is the targeted levels of retained earnings being substantially higher for Plan 5 solely due to the imposition of the strict 75:25 debt:equity ratio (without any supporting analysis to show that Plan 5 in fact has any higher need for retained earnings or reserves to achieve rate stability than Plan 1). The difference is very material - $6.0 billion in retained earnings targeted for Plan 5 versus $4.6 billion for Plan 1 over this time period. Given Hydro has proceeded to develop rate design Alternative Methodology #1 and #2, each of which suggests Hydro is prepared to significantly yield on the debt:equity target, this rate impact should be viewed with caution. With a yielding on the debt:equity target, the rate impacts to 2031/32 are nearly identical between Plan 5 and Plan 1. There was no opportunity to cross-examine Hydro on these Rate Design Alternatives, so it is not clear the extent to which they truly represent a potential policy decision to yield on financial targets imposed on customers, or are solely a theoretical analytical exercise.

[33] Exhibit MH-104-12.

[34] Under the Main Submission Rate Design Methodology the difference is 112% for Plan 14 versus 94% for Plan 5, or 19% higher; under Alternative #1 the difference is 70% versus 56% or 25% higher, and under Alternative #2 the difference is 69% versus 53%, or 30% higher.

10) Has a Full Assessment of the Benefits and Costs of the PDP been Provided?

No. This is because aspects of the plans either cannot be easily quantified today or are not readily quantifiable.

On the matter of benefits, the analysis to date does not appear to fully incorporate the benefits of cross-border transmission:

> MR. PELINO COLAIACOVO: From a financial perspective, in our view export and import interties create a broader set of options for value generation. There is opportunity in trade, and there is opportunity locked up in Manitoba Hydro's storage capabilities that could be usefully exploited with additional interties.
>
> So from a financial perspective, that's the kind of perspective that we have. A 750 megawatt intertie is going to give you greater access to market, both for import purposes and export purposes and trade purposes.
>
> MR. ANTOINE HACAULT: And is it your point, sir, that we haven't really analyzed all those benefits, so we can't see them in the record the way it's set up today?
>
> MR. PELINO COLAIACOVO: I think that's true. You know, the -- for all the fact that the -- that this process has had to consider an enormous volume of data and a variety of options and possibilities, there are still others, I think, that are available that haven't been fully explored. And as I have referred back before to La Capra's statements about optimization, you know, I think there are optimization opportunities that are likely there (Tr: 7525 – 7526).

One example is the incomplete consideration of the full transfer capability of the line:

> MR. ANTOINE HACAULT: So if you move to what you're suggesting, the 500 kV line, what's the optionality and how easy is it to move up to that 1,100 megawatt?
>
> DR. DAVID JACOBSON: There's no additional facilities in Manitoba required. As I mentioned on the Monday presentation, some additional facilities in the US are required to get past some congestion down south, so the 500 kV line by itself, expecting the Preferred Development Plan can do seven fifty (750) for sure, probably eight (8) -- eighty-three (83) with no additional facilities. Beyond that, additional outlet out of Blackberry will be required to get up to 1,100 megawatts, but no

> additional facilities in Manitoba, and there's even potential for higher without additional facilities in Manitoba, but those haven't been studied (Tr: 2425-2426).

An additional benefit not yet included is that the analysis to date appears to focus on contractual discussions with Manitoba Hydro's traditional trading partners and export market range. However, the 750 MW transmission line component of the PDP also expands the range of possible counter-parties, which is beneficial to trading:

> MR. ANTOINE HACAULT: … We've gone through all the potential agreements for more energy. We've gone up on the optionality to send and to import greater amounts, easier with the 750 megawatt line. Those are all things that are in addition to the specific things we've contemplated in Pathway 5.
>
> Is there something else that you can put on the public record that we haven't considered?
>
> MR. DAVID CORMIE: Yes, the last thing is the option of expanding the market into Wisconsin is created by the WPS sale and the transmission reservations that were put in place as a result of that, and it gives us the option now to deal with all of the small utilities in Wisconsin who aren't, by themselves, big enough to be anchor tenants to justify a transmission investment, but could be off-takers.
>
> And, so as -- what the WPS transaction and the associated transmission investment does is it essentially doubles the size of Manitoba Hydro's market. The -- Wisconsin and Minnesota are essentially the same size when you look at an electric market, and there are other utilities there, Madison Gas and Electric, Wisconsin Public Power, We Energy, they're all in the same situation that Wisconsin Public Service is in. But now that we have a plan to get transmission into Wisconsin, and that transmission is driven by the power purchase arrangement with Wisconsin Public Service, now we can start marketing to those customers, and the more customers we have competing for our product, the higher price we can charge and the more value we can get for our product.
>
> And, so that's optionality is valuable. We don't have to go back to the same customers over and over again and say, We want to rebuy our power. We can say, You know what, we have customers over here willing to pay more. We may end up selling it to the existing customer set, but it's because we now have a larger market, we've doubled the size of our market by having market access into Wisconsin.
>
> That optionality -- the value of that optionality is huge, because it will benefit Manitoba Hydro forever, as long as we have surplus electricity.

> MR. ANTOINE HACAULT: Sir, you said it's huge but it hasn't been quantified in this Application, has it?

> MR. DAVID CORMIE**:** No, no, we haven't put any value on that, no (Tr: 2426-2428).

In addition, in respect of the transmission line, there is a potential for economic upside due to unwinding the Manitoba Hydro ownership in 49% of the US assets that has not been included in the quantitative analysis:

> MR. ED WOJCZYNSKI: … we're planning to unwind our transmission investment, and that's been referred to a couple of times, but we haven't really put -- we don't have a specific dollar value, but the thinking is that it would cer -- that it would -- it's likely to be more than a hundred, or even possibly $200 million.

> But we don't have anything finalized on that, so all we can do is give a preliminary indication of the order, and it's no guarantee that's going to happen, but we're intending to, and we think there's a good chance that will happen. And that's NPV … (Tr: 2434-2435)

On the matter of reliability and energy security, Mr. Wojczynski provided extensive discussion at pages 2681-2694 of the transcript highlighting that there is a real and quantifiable benefit to customers from pursuing the PDP in terms of reduced outages. Using industry-standard metrics, this is a benefit exceeding $100 million compared to All Gas. Further, there is an added benefit of the transmission line in particular in regard to the concept of “energy security”, as follows:

> MR. ED WOJCZYNSKI: Energy security and capacity reliability, another one (1) of these societal benefits, and Dr. Shaffer didn't include a dollar value in his analysis partly because some of our work was premature, and we have, as we testified earlier, $100 million of reliability benefit from a capacity point of view for Manitoba customers, not export customers.

> I was asked that day about energy security. Do we have a dollar value? And, as I indicated, No, we don't, and that it's harder to estimate that compared to capacity, and I didn't have a reliable way of coming up with a number.

> But we've given it some serious consideration since that time, and our conclusion is actually -- would be significantly more than the $100 million for capacity reliability, and the reason is, capa -- customer supply interruptions during energy shortages would tend to be less likely to happen than capacity ones, but when they happen, they will extended, not for hours -- weeks, days and months, because if we're into maximum

> imports and running our thermal to the max and we've got a -- and we have less water, or there's something else, there's nothing left for us to do
>
> …
>
> So we actually view the energy security as being significantly more valuable than the capacity reliability, and in our view, the best way to deal with these uncertainties and provide that is through this expanded interconnection (Tr: 3700-3701).

As to adverse impacts that have not been fully embraced in the filing, there are two of note. In each case, these represent policy decisions of Hydro that act to significantly exacerbate the adverse short-term financial impacts of any capital-intensive development plan, but in particular are adverse to the PDP. In this manner, Hydro is in effect undermining its own advocacy of the PDP.

The first unquantified adverse impact is the approach to depreciation. Hydro has provided its financial forecasts on the basis of a depreciation methodology for the new plants called Average Service Life (ASL), using a coarse componentization (e.g., applying a single rate to the entire plant, rather than breaking out individual turbines, versus spillways, etc), and with no Net Salvage. This is inconsistent with Hydro's policy position that it should transition instead to a method of depreciation known as Equal Life Group (ELG) with no Net Salvage.

> MR. DARREN RAINKIE: What happens if you're applying an EL -- a more refined methodology, like ELG, is you're starting to stratify some of the earlier assets in the pool, which has the effect of then reducing the average service life and increasing the depreciation rate (Tr: 3337).

Alternatively, Hydro indicates that it might be able to retain the ASL method in future but only with a much finer componentization:

> MR. DARREN RAINKIE**:** … if we moved to ASL we believe that we're going to have to componentize to a much more detailed level. And if we do that and start pulling out some of the shorter life assets out of the ASL, we believe it's going to produce similar results (Tr: 3337).

Hydro explains that the ASL method using the coarse componentization is used for the PDP analysis to calculate the depreciation for the new assets as: "we don't know what the ELG rates are for Keeyask and Conawapa" (Tr: 3339). Hydro further notes that they will not do a detailed component analysis until "…closer to the in-service date of

Keeyask and Conawapa, or when they're in service…"[35]. The concern arises that under either future methodology that Hydro proposes (ELG, or ASL with added componentization), the evidence is that depreciation expense will be higher than reported in the NFAT financial analysis. Using the Wuskwatim ELG rates as a proxy for where the future Keeyask and Conawapa depreciation could be set ("the best proxy we have right now"[36]), this impact could be $31 million per year[37]. The net benefit to customers, if any, of this more aggressive depreciation would only arise many years into the future, and as such this effect further exacerbates the ratepayer impacts arising from the capital intensive development plans. There would appear to be no practical constraint on Hydro from adopting depreciation rates consistent with the NFAT analysis (ASL, with no Net Salvage) except Hydro's policy decision to adopt more aggressive depreciation.

The second major area of concern in the rate impact presentations relates to Hydro's financial targets. The information provided in Exhibit MH-104-12-6 shows the rate impacts based on three rate setting methodologies.

1) The first is the methodology from the original NFAT filing, which is based on achieving Hydro's corporate debt:equity target (75:25) by 2031/32.

2) The second methodology (called Alternative #1) is based on applying 3.95% rate increases to every year until the 1.2 interest coverage target is achieved, and then to maintain only a 1.2 interest coverage. This Alternative yields significantly on the debt:equity target (only achieves debt ratios on the order of 81-89% by 2031/32[38]).

3) The third methodology (Alternative #2) is similar to Alternative #1, except that it increases the annual rate impacts in certain of the early years (2016-2022) to "… improve the net income/loss…" to an "…acceptable level."[39] Similar to Alternative #1, this represents financial scenarios that materially miss the Corporate

[35] Tr: 3339-3340.
[36] Tr: 3340.
[37] Tr: 3341.
[38] Exhibit MH-104-12-6, page 2.
[39] Exhibit MH-104-12, page 2.

debt:equity target (only achieves debt ratios on the order of 78-85% by 2031/32[40]).

Hydro has elected to focus on Alternative #2 in presenting its summary results in Exhibit MH-104-12-5. This is potentially problematic, as Alternative #2 only arises in the event that Hydro adopts a policy change to yield on its debt:equity ratio. No evidence was provided that such a policy change has been adopted. Further, this approach is materially adverse to the Plans that must write-off sunk costs. In calculating the needed “improvement” to annual net income, Hydro assumes all sunk costs for plants not constructed as part of the Plan will be amortized over 18 years, and as part of this amortization they would a material impact on the annual net income that must be made up from high annual rate increases. This is not what would occur in practice, for two reasons:

1) First, under any Pathway that retains decision points within the next number of year related to new hydro, many if not all of these costs are unlikely to be amortized off at all:

> MR. BOB PETERS: Would it be correct, Ms. Carriere, that if the plan that was ultimately the one that found approval was Gas/Keeyask, you wouldn't then need to write off any of the Keeyask sunk cost because that would still be in your planning studies, in your planning horizon?
>
> MS. LIZ CARRIERE: That's correct.
>
> MR. BOB PETERS: And this $1.6 billion a year over the eighteen (18) years, you're looking at roughly $90 million a year that's being added to the financial analysis to be recovered in rates?
>
> MS. LIZ CARRIERE: Yes, approximately, assuming the eighteen (18) year amortization period.
>
> MR. BOB PETERS: And so as long, Ms. Carriere, as the Keeyask or Conawapa generating stations are still in the planning horizon of Manitoba Hydro, those costs would not have to be recovered as sunk costs, would they? They would wait until the plant came in service?
>
> MS. LIZ CARRIERE: That's correct (Tr: 2883-2884).

[40] Exhibit MH-104-12-6, page 3.

And as further explained by Mr. Rainkie:

> MR. DARREN RAINKIE: … And that's the difficult part about assessing the accounting side of this, is what is the circumstance we're dealing with? Is it a circumstance where these plants are deferred forever and it's never going to come back into the power resource plan as a resource? In that case, I think our auditors would be pushing for us to write these off rather quickly.
>
> If it's a situation where we're saying not now -- these are the -- as I understand it anyway from my, you know, accountant perspective as opposed to a power resource planning person, these are the most economic plants that we have in the great abundant resources of Manitoba that we have and will always probably be in our stack somewhere.
>
> In that case we would, on an annual basis, have to assess the amount that we were holding in construction work in progress and see if there was continuing benefits of those -- of the costs. Some of those costs may have enduring benefits. Studies about the geotechnical aspects that wouldn't change because the landscape is not changing. Some of the studies environmental may not have benefits because environmental changes may occur in -- in terms of legislation. So you may have to write some of those costs off sooner rather than later (Tr: 3413-3414).

2) Second, it is unlikely that any costs to be written-off would become an annual amortization, as opposed to simply being charged to income at one time. As such they would not be a hit to net income on a sustained basis year-after-year as suggested by Alternative #2:

> MR. DARREN RAINKIE: We used to have a -- an accounting policy at Manitoba Hydro of amortizing planning study costs over fifteen (15) years, and some of the accounting standards changed a few years ago. We stopped that and we expensed those costs. (Tr: 3157).

In short, absent confirmation that policy changes have been adopted by Hydro in the form of lower financial targets (particularly debt:equty targets), the rate impacts shown under Alternative #2 must be viewed as directionally reasonable, but the specific values as suspect.

11) What are the Government and Other Stakeholder Benefits of the PDP as proposed?

The government benefits from the PDP, and the other opportunity-based plans comprising the bottom half of Exhibit MH-192 are extraordinary. These benefits were summarized in MIPUG-9-2, the Pre-Filed Testimony of Mr. Bowman[41] as approaching $4 billion NPV for the full PDP over Plan 1 (All Gas). This includes only direct Hydro impacts – payments for Water Rentals, Debt Guarantee Fees, Capital Taxes and growth in Shareholder's Equity. For the previous Plan 4 (Keeyask 2019, 250 MW line) the benefits were approaching $2 billion NPV over Plan 1. Plan 5 (Keeyask 19, Gas, 750 MW Interconnection) is expected to be slightly higher than the Plan 4 amounts. The baseline used in this analysis was Plan 1 (All Gas) which has an approximate total of $8 billion NPV over the 50 year financial analysis time horizon[42].

In short, while ratepayers bear the risks of the PDP, the expected benefits available range from zero to perhaps 1% benefit over the rates that would otherwise be paid, the government benefits range from a 25% to 50% increase[43] in the scale of benefits otherwise available under Plan 1.

These government amounts do not include other benefits that government and other stakeholders in the province will see from the PDP such as jobs, income taxes, First Nations investment and benefits agreements, and GHG and other emissions benefits.

There is one final perspective offered on the government benefits topic, and that is a noted omission in the filing. The implication in the analysis to date is that government benefits arising at a time of increased rate pressures are the full picture in terms of government impact. This is not true, as noted by Mr. Colaiacovo:

> THE CHAIRPERSON: -- the number of other benefits that flow [to the Government] that -- some of which can be quantified, some not, but, generally speaking, the province benefits?

[41] MIPUG-9-2, Pre-Filed Testimony of P. Bowman, Revised February 28, 2014, pages C-38 and C-47.
[42] This means NPV benefits over the 50 year financial analysis time horizon for the PDP are expected to be $12 billion total, for Plan 4 the NPV forecast was $10 billion total and Plan 5 would be slightly higher than $10 billion NPV.
[43] $2-$4 billion in added government benefits compared to the $8 billion baseline.

> MR. PELINO COLAIACOVO: I think that's right, with the one (1) caveat that I don't think has been fully explored is the costs to the province's economy of rate increases that are entailed in the plans.
>
> And so I think at the very outset Manitoba Hydro made clear that there is -- the province will require some new generation capacity. The question is: What kind of generation capacity and when?
>
> And the province will face higher rates. The question is: Exactly how much higher and when?
>
> So it's all a comparative analysis. It's a relative analysis. But increased rates are a drag on the economy and they have an impact on the economy, particularly if those rate increases are greater than rate increases that are occurring elsewhere in other competitive jurisdictions. And I don't think there has been, at least I have not noted on the record, any macroeconomic analysis of the magnitude and timing of those rate increases and the impact that it has.
>
> So that, broadly speaking, is a cost to the government, because the government generates revenue from growth in the economy. But all of the other benefits that are associated with it in terms of jobs and regional economic development, and so on and so forth, are benefits that I think have been addressed elsewhere through this process (Tr: 7529 – 7530).

There are two implications that can be drawn from the perspective that rate increases have ripple effects not fully explored:

1. The analysis may fail to fully capture that substantial financial benefits to government including capital taxes, water rentals and debt guarantee fees (as well as other social benefits associated with jobs and regional economic development) arise at a time when the PDP would be placing upward pressure on rates (the next 20 years); moreover, the PDP would be an additional factor over and above the significant upward pressure already being experienced due to Bipole III and other capital investment. Relative to other plans where the government collection of fees from Hydro happens more smoothly over time (resulting in a similar effect for rate increases) this has economic implications that should be considered; and

2. Any move to revise the scale of government benefits from the extent currently targeted to provide rate and risk relief to customers is not a full net loss to the government – as to the extent a rebalancing benefits electricity rates there will be

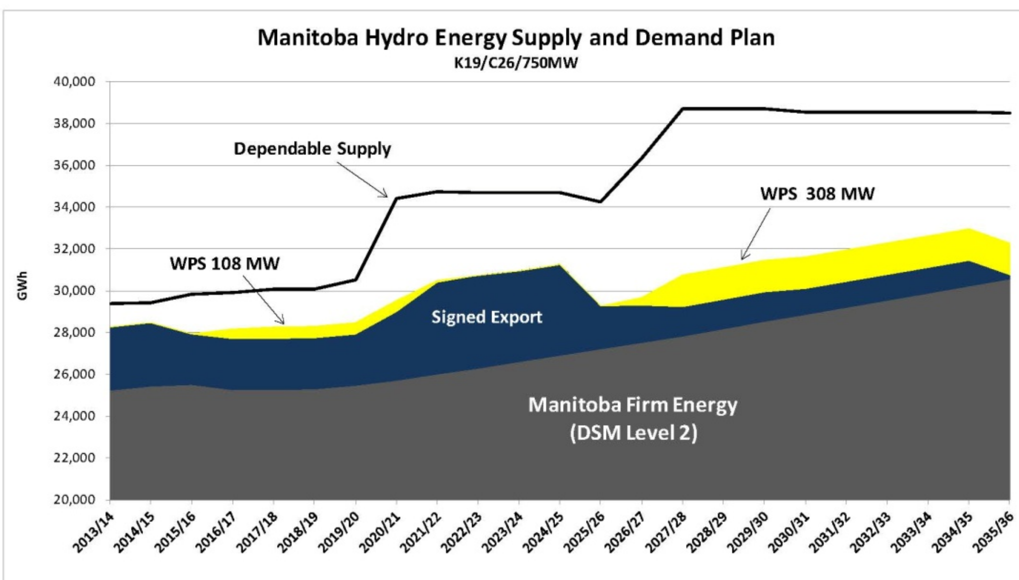
offsetting government revenue arising from lower rates, more economic growth, larger disposable incomes, etc.

12) How Should Conawapa be Approached Today?

Conawapa is a component of the PDP, but there are multiple paths through the Opportunity-based pathways that do not ultimately result in Conawapa being constructed. As such, there is room for considerable uncertainty in regard to Conawapa at this time. There are two main constraints in regards to Conawapa at the present time:

1) Conawapa remains speculative and very far out in time with regard to current assumptions. As described by Morrison Park, Conawapa should be viewed as a distant “development opportunity”[44]. This is supported by Exhibit MH-138 which shows that even with all signed contracts today, the energy represented by Conawapa (the last step increase in supply in the below figure) is entirely being developed on speculation. Secure contracts are required before the Conawapa opportunity can be properly understood.

Manitoba Hydro Exhibit MH-138 OF Firm Energy Forecast Based on DSM Level 2 With No Pipeline Scenario



2) The economic profile of Conawapa is such that, under the present modelling, it brings massive benefits to the provincial government and economy, with effectively no benefit and major risks to ratepayers. This will not ultimately prove to be a tenable development concept, as noted by Mr. Bowman:

[44] Tr: 7441-7442.

> MR. PATRICK BOWMAN: The issue is you've got a project [Conawapa] that it doesn't matter how much anyone likes it or hates it at this point in time. Nobody can make a decision to go forward with it, because there's way too many steps that have to be done between here and there. So no matter what happens, there's time.
>
> But on the basis of even pessimistic numbers that have been presented, there are some very large consolidated benefits between the provincial government, the utility, and its ratepayers. They are very poorly distributed at this point, but they're very large, even on pessimistic assumptions. That could change in the years that are to come, but at this point, they're real, and I think it's important to pay attention to that as an opportunity for Manitoba.
>
> The main point of our conclusion is, or what I've put down here is, right now, you have - - you don't have to make a decision, but even if you -- in respect to building, but you do have to make a res - - decision in respect to protecting, or someone has to make a decision in respect to protecting. And the benefits are -- appear real, that are even in some pessimistic assumptions. The problem is, if you're not careful about assessing them, you're assessing them under a distribution of the pie, if you like, that, in my view, is unrealistic. I don't think if the distribution doesn't change, I don't think Conawapa would go forward. I don't think it's credible. I think ratepayers would be ill served by that.
>
> …
>
> but the pie is large enough that -- and I've had experience dealing with governments on these type of matters that it would seem reasonable, likely, that people would want it to go forward and be prepared to find a way to re- carve it (Tr: 10080 – 10081).

There is no evidence before the PUB that pursuing Conawapa in 2026 or 2031 will lead to net rate benefits until, at best, many decades into the future.

However, there is reason to expect that both of the above issues could be resolved by Hydro within a reasonable period of time – for export contracts it is clear that there is expected to be movement within 12 to 18 months[45], and for the provincial government

[45] For example, as noted by Mr. Cormie and Dr. Jacobson a SaskPower 500 MW term sheet business arrangements could be worked out "relatively quickly" following conclusions of an interconnection and cost study, that Dr. Jacobson indicates could be completed "within 6 to 12 months" (Tr: 2419-2421). Additionally at transcript page 2417, Mr Cormie notes: "Great River Energy knows their -- that Manitoba Hydro needs to make an investment decision relatively soon, and -- and given that the current in-service date for Conawapa

sharing revisions, securing a commitment to revised benefit sharing should be quick - not longer than is needed to confirm Conawapa remains a core part of the Province's Clean Energy Strategy.

It is important to remember that there will ultimately be a number of measures to help manage the risks associated with Conawapa that cannot be fully understood today:

- The high capital cost scenarios for Conawapa continue to be analyzed as a downside, however Conawapa decisions will only be made after the capital costs of Keeyask are known (which has similar cost drivers). As a result, Hydro indicates it is "not plausible" that Conawapa would proceed with high capital cost assumptions (Tr: 6603).

- Conawapa has considerable flexibility for in-service date. Hydro's evidence is that 2026 remains the plan as it best suits potential counterparties (Tr: 2397) but that if the economics are improved with delay, 2031 is still fully within the planning horizon (e.g., Tr: 2401; Exhibit MH-104).

With regard to protecting Conawapa, different values have been presented for the ongoing costs for protecting the project. Using the values from the optionality assessment conducted by Hydro[46] the costs for the next four years (to 2018) are $308 million (2014$) to protect a 2026 ISD, versus only $89 million (2014$) to protect a 2031 ISD[47]. Presumably spending any less than $89 million would eliminate even 2031 as an in-service date possibility.

By 2018 Hydro indicates it would be ready for a construction commitment for a 2026 ISD, similar to the current situation with regard to Keeyask. The potential for the project proceeding for 2026 should not be abandoned. However, neither should the Board be satisfied with a lack of a public decision point for at least four years (to 2018) and more than $300-$400 million in more sunk costs. One possibility is that any current sanction of ongoing Conawapa studies should not extend more than two years, or perhaps to a maximum expenditure level of $100-$150 million, before some form of simplified public review is undertaken to establish ratepayer benefits and overall direction.

aligns with the year in which they've indicated they need the power, there will be some urgency for us to come together within the next year on defining something that can be put into a term sheet."

[46] Provided at PUB/MH-I-238c in 2014$.

[47] Attachment PUB/MH I-279 page 4.

13) Is There an Option to Proceed with the US Transmission Line and the MP 250MW Export Contract Without Keeyask?

MIPUG was not part of the hearing that dealt with commercially sensitive information, including unredacted contracts. However, the evidence from Manitoba Hydro appears to suggest that a possibility of proceeding with the MP sale and the 750 MW line without also advancing Keeyask is solely a theoretical opportunity that cannot be pursued in practice (Exhibit MH-201). Due to the limited publically available information on this subject, MIPUG takes no position at this time.

14) Is DSM a Viable Alternative to the PDP?

Industry has been one of the largest and most committed participants in Hydro's DSM programming. At the same time, the scope of Hydro's DSM programming has not always been as accommodating to many credible options for industry to participate in DSM:

> MR. BILL TURNER: … industries and other jurisdictions are often offered a much wider range of ways to help manage their load and power costs and to participate in alternative rate setting. There are minimal such offerings in Manitoba. And one (1) of the key offerings that does exist, the Curtailable Rate Program, has been capped by Manitoba Hydro.
>
> Industries are very eager participants in DSM in Manitoba. So it is encouraging to see that Hydro is looking to expand the DSM programming and become more creative with such options as invested generations of power from waste products.
>
> It remains to be seen if the curtailable program caps will be removed and the prices Hydro will pay for the power generated by industry will be sufficient to actually achieve any successes. It also remains to be seen whether added pursuit of DSM can be achieved without driving up rates for other customers as a new form of cross subsidy (Tr: 7205-7207).

The evidence is that the DSM proposed by Hydro, to the extent it can be achieved (e.g., Level 2) could prove to be a beneficial source of additional power resources. The supplementary evidence of Mr. Bowman (Exhibit MIPUG-9-4) demonstrated that DSM Level 2 provides economic benefits from both a participating customer perspective (Figure 1) and a Manitoba Hydro perspective (Figure 2 and 3) noting "every plan economically benefits from adding DSM up to Level 2"[48].

The more important conclusions however relate to the potential for DSM to eliminate the need for the PDP. As established above, the PDP (or alternatives such as Plan 5) are not being approached on the basis of need. They are being approached on the basis of a business case that is marginal on rates, but beneficial on unquantified factors and intangibles, and to other stakeholders beyond ratepayers (without rebalancing of government benefits). DSM can complement these benefits, but do not obviate or eliminate the basis for the PDP variants:

> MR. PATRICK BOWMAN: … Based on what we knew in the original NFAT, we had concluded it didn't appear to be the case. It appeared that

[48] Exhibit MIPUG-9-4, pages 1-7, dated May 1, 2014.

> DSM would complement the plans, that it would not compete with the plans. And in general, that is underlined by the DSM we've seen, that the DSM that's been proposed complements the plans. It differs by plans. Some of them it helps more than others. And the test is the -- is of the type I described, that DSM is best under plans that have relatively large transmission and that are able to adjust the generation and complement to deal with the DSM.
>
> So Plan 5, Keeyask/750 has large transmission, 750 megawatts of transmission. It only has Keeyask. It doesn't have Conawapa being brought in for a specific date. So as the numbers sit right now, it does better with DSM, as we just talked about (Tr: 10095-10096).

15) Has Hydro fully captured the benefits of the Curtailable Service Program?

Hydro has not fully captured the benefits of the Curtailable Service Program. This DSM program is one of the long-standing options under DSM programming, and is unique among Manitoba Hydro's DSM initiatives in that it is particularly aimed at providing capacity and helping with reliability (where most DSM programs are aimed primarily at providing energy benefits).

The Curtailable program was described by Hydro as follows:

> THE CHAIRPERSON: Could you give us a more basic explanation of the Curtailable Rate Program, defining it a little bit more granular?
>
> MR. DALE FRIESEN: Yeah, I'll give you a little bit of a practical example. So what the Curtailable Rate Program does is it allows customers to subscribe blocks of load that they are willing to interrupt in exchange for some type of compensation. And the value of that compensation is determined by the value to Manitoba Hydro of that response mechanism.
>
> So we have different options for responding to different types of events. We could build a peaking plant. We could build -- we could have energy in storage. We could build more firm capacity. We -- there are many different options that are available to respond to events within the system that may cause sudden increases in load or may result as a result of equipment failing or equipment going out of service suddenly.
>
> Our program requires customers to subscribe a minimum of a 5 megawatt block, so that precludes, at this point, smaller customers from participating in that program. It's primarily our larger customers that can participate in this program. And they -- what they have done, it -- particular customers that have processes that can be shut down very quickly with minimal disruption and restarted quite quickly with minimal disruption. There are many industries where you cannot do this. An interruption of this type would result in an eight (8) -- six (6) to eight (8), ten (10), twelve (12) hour recovery period. But in certain industries, it's possible to very rapidly turn down load and then very rapidly turn up load when the event has passed.
>
> So at present we have four (4) customers enrolled in this program, all in our top consumer group. And they provide us with these services in exchange for both a standby payment, depending on the option they choose, and a -- in some cases it's a payment that occurs when we actually physically curtail them. (Tr: 1150-1152).

And further:

> MR. ANTOINE HACAULT: Could you give us an example of a short-term unexpected increase in firm load where you would use that -- am I right in saying resource or capacity?

> MR. DALE FRIESEN: That's correct. A good example this past summer occurred when we lost one (1) of our bipoles for a short period of time. And so it was, I believe, a fairly warm period of time or a very fairly high temperatures. We have fairly high peak loading in our system at that time. And we used the curtailable load to manage our system peak load within the province while we rectified the situation with the bipole. So that would be a typical example; unexpected, and it provided us with a very rapid short-term response. And by, "rapid," I mean about a five (5) minute response (Tr: 1149).

Mr. Turner, Chair of MIPUG noted:

> MR. BILL TURNER: …industries and other jurisdictions are often offered a much wider range of ways to help manage their load and power costs and to participate in al -- in alternative rate setting. There are minimal such offerings in Manitoba. And one (1) of the key offerings that does exist, the Curtailable Rate Program, has been capped by Manitoba Hydro.

> …

> It remains to be seen if the curtailable program caps will be removed (Tr: 7206).

The evidence from the DSM materials shows that the program has had participants consistently since 1994/95 and after a number of years of ramping up, has had consistent participation at approximately the 150 – 190 MW level for since 2003/04[49] and expected to continue at this level through 2027/28[50]. Further, as noted by Mr. Forsyth of Gerdau, it is not a lack of customer interest that maintains the program at this level, but rather caps imposed by Manitoba Hydro:

> MR. DAVE FORSYTH: We have approached Manitoba Hydro many times to subscribe to the appropriate program, but, as Mr. Turner stated earlier, their Curtailable Rate Program is closed to new entrants. Hydro has also -

[49] NFAT Filing, Appendix E, Appendix B.1
[50] NFAT Filing, Appendix E, Appendix A.1

> - has no other options to help us control the power cost. As a result, there is little we can do to help manage these costs.
>
> We and other members of MIPUG have shared demand response program information and proposals from other jurisdictions with Manitoba Hydro in areas where we operate, yet Manitoba Hydro has generated sixteen (16) scenarios in the Needs For And Alternatives To study, and not one (1) of them considers additional demand response participation by Manitoba industrial customers.
>
> Energy efficiency is one of the few tools -- or DSM, one of the few tools at hand to help Gerdau's Manitoba facility improve its competitiveness, and we have invested heavily, improving our costs and benefiting the environment (Tr: 7215-7216).

One major reason why it appears Hydro has artificially constrained the Curtailable Rates Program is because Hydro materially devalues the program due to an overly conservative assumption that customers may en masse quit the program.

> MR. ANTOINE HACAULT: …We had talked about the role of curtailable in the previous panel. And I just wanted to have you explain with respect to Option E shown here, what's -- how can Manitoba Hydro use the Option E, which allows it to curtail for up to ten (10) days for three (3) separate times during the calendar years. How can that be used by Hydro?
>
> MR. DAVE CORMIE: The thinking behind designing that option was to assist us during a period of extreme weather, or during a period that the power system is experiencing a -- an outage. Let's say we were in a drought. The 500 kV line, and we were importing on that, it went -- it went out of service for maintenance outage, or for whatever reason, that we could curtail load for up to ten (10) days. And that's what it was used for --
>
> MR. ANTOINE HACAULT: Okay.
>
> MR. DAVID CORMIE: -- was to get through unanticipated system operating events.
>
> MR. ANTOINE HACAULT: And this program has been in place for, I think, a couple decades. Is that fair?
>
> MR. DAVID CORMIE: Has it been that long? Yes. Mr. Wojczynski and I were on the -- in the group that designed it, yes.
>
> MR. ED WOJCZYNSKI: Yes, I -- and that was a long time ago.

MR. ANTOINE HACAULT: And my understanding, it's still part of the plan going forward to have this available?

MR. DAVID CORMIE: Yes.

MR. ANTOINE HACAULT: Now, with respect to Options A and 'C', I don't know if you can provide a quick explanation of why that's there. And there's one that's just a five (5) minute notice and one's an hour notice.

How do those fit into Manitoba Hydro's needs?

MR. DAVID CORMIE: Option A is very useful. It gives us a quick response resource. Customers are able to curtail their load quickly. And we can use that in an emergency. And Option C, less useful because to be useful in an emergency, you actually have to anticipate the emergency an hour in advance. And so it's really not very useful. And in all the years we've had that program, I don't believe we've ever made an Option C curtailment.

We still have it in the program, but I -- it doesn't bring a lot of use and it doesn't cost us really anything to have it in the program.

MR. ANTOINE HACAULT: And would I be correct in categorizing the Option E as really an energy option?

MR. DAVID CORMIE: Yes, it's a -- it's -- it provides us an ability to reduce energy demand in the system during emergency events.

MR. ANTOINE HACAULT: And if we flip back to page 58. There -- the customers aren't identified, but one (1) customer in particular has the ability to do an Option E at over 192 megawatts average on peak?

MR. DAVID CORMIE: Yes, that's correct. And I notice on the table there is an Option C curtailment here, so I stand corrected.

MR. ANTOINE HACAULT: Thank you. Now, that energy, although you -- I think you agreed with me that Customer 1 that provided the 'E' option that was kind of an energy type of option. That 192 megawatts is not included in the energy tables, I believe, planning?

MR. DAVID CORMIE: Are you asking: Do we include curtailable in our planning? No we don't.

MR. ANTOINE HACAULT: And that's both for energy and capacity that you don't include these, correct?

MR. DAVID CORMIE: That's correct.

> MR. ANTOINE HACAULT: Okay. Thank you.
>
> MR. DAVID CORMIE: If we had many customers and there was diversity in our customer base, then I think we could start counting on an average amount.
>
> But because the number of customers is very small, to assume that that customer will continue ten (10), fifteen (15), twenty (20) years to take service under the program, whereas if we add a hundred customers you would say, Well, some are going to come and some are going to go. But because the customer base is so small, we just don't see it as meeting our firm requirements.
>
> MR. ANTOINE HACAULT: So the Corporation is taking a very conservative approach. If there's been a customer there for twenty (20) years, it assumes the customer won't exist next year, for planning purposes?
>
> MR. DAVID CORMIE: Yes, we're saying that. And we're also saying that we're not in a capacity-short situation. So, you know, is -- if we're building for capacity and we're capacity long, then in the short-term, it doesn't really provide value. In the very, very long-run, we still see ourselves as being energy dependent. So I don't know if it would really change our plans whether we included it or not (Tr: 2636-2640).

The three critical aspects of this exchange between Mr. Hacault and Mr. Cormie are:

- Conservation assumptions result in caution about whether there will be any program participants in future.
- At least one component (Option E) provides energy benefits while the remaining options provide capacity benefits. Option E (totaling 80MW per Exhibit MIPUG-20-4, page 58) provides for 3 interruptions per year of 10 days in length, or 57 GW.h of energy benefit. This is ignored in Hydro’s planning. The capacity benefit of 228 MW is similarly ignored.
- While the capacity benefits in themselves may not change Hydro’s planning (Mr. Cormie indicates he doesn’t know that they would), the combined capacity and energy benefits have not been modeled.

The position of Hydro ignores that there has been participation in the program for decades, participation is projected to continue for decades, and that there are more customers seeking inclusion into the program than Hydro is willing to accommodate.

Further, the program provides benefits to other customers in the form of both local and system-wide reliability, and for industrial customers facing upward rate pressures, is one of the only options available under Hydro's system to help control power costs through more flexible operation (unlike other jurisdictions where a much wider variety of such options are available[51]).

As a complementary option to new resource development, the Board should ensure that options to participate in the Curtailable Rates DSM program are not capped and that further options for customer participation are explored.

[51] See Transcript pages 7213 – 7215 for examples from Mr. David Forsyth, Regional Energy Manager for Gerdau, on energy conversation measures in other jurisdictions.

16) What Tests Should be Applied to Determine the Cost-Effectiveness of DSM?

The pursuit of DSM by a utility drives a different economic profile for each of the different parties affected by the investment. Participating customers can readily judge their own priorities and payback from participating in a program. Hydro must consider the resource acquisition cost of the power acquired (including lost revenue), as part of the PACT test, as discussed by Mr. Bowman in the response to CAC/MIPUG 7(a):

> When in a mode of resource acquisition, such as the present NFAT, DSM resources can be an alternative to new generation. However, DSM resources do not have a perfectly equivalent financial impact to acquiring new generation due to the impacts on utility revenues from reduced sales. Nonetheless, LUC based screening and a PACT is a reasonable test for the purposes of comparing among DSM program options.
>
> a. For example, in Appendix E (Hydro's 2013-2016 Power Smart Plan) page 41 shows that the LUC for the Industrial Performance Optimization Program is 1.5 cents/kW.h[52]. This is the largest single long-term DSM program Hydro offers[53]. When combined with the revenue loss associated with this power (approximately 3.9 cents/kW.h)[54] this means the power is acquired at 5.4 cents/kW.h net cost to Hydro. This compares favorably with Hydro's main other resource options (such as Keeyask at 6.0 cents/kW.h; Conawapa at 6.7 cents/kW.h and gas at 7.5-9.7 cents/kW.h)[55]. These values would suggest there may remain further room for somewhat more activity under the Performance Optimization program by adding in measures that may be slightly less beneficial than those already included, without undermining the viability of the initiative.

[52] Appendix E: 2013 – 2016 Power Smart Plan, page 41.
[53] Appendix E 2013 - 2016 Power Smart Plan, Appendix A.2.
[54] See MH/MIPUG I-1 where this average cost of energy for the GSL>100kV class is calculated.
[55] NFAT Chapter 7 Tables 7.3 and 7.4.

b. By comparison, the commercial building envelope programs (windows and insulation) at 2.4-2.5 cents/kW.h LUC[56] if applied to GS Small customers (with an average rate of 7.3 cents/kW.h[57]) would show total cost to acquire the power at upwards of 10 cents/kW.h. This is a more challenging DSM program, but remains potentially favourable if there are other characteristics that are beneficial to Hydro's costs (e.g., benefits to avoiding distribution system expansion, or if the loads to be saved are higher cost than average as they are concentrated in winter or in daytime hours).

Note that in the assessments above, there is no analysis of the customer's investment. For example, it may be that the customer is investing $100 for every $10 of energy saved – but this may still be beneficial for the customer due to improved comfort, or more stylish architectural details, etc. The economics of the customer's decision should be left to the customer.

This economic profile of DSM requires the consideration of revenue and customer impacts for non-participating customers as a key priority, as described by Mr. Colaiacovo:

> MR. PELINO COLAIACOVO: So DSM programs on an aggregate basis are unambiguously good, I think is one (1) way to put it. The -- and an economically justified DSM program entails the investment of some capital in order to reduce consumption over time, and that reduced consumption benefits the system as a whole.
>
> However, any DSM program will only be taken up by a fraction of participants in the system, and that fraction of the participants in the system will reduce their consumption, and they will pay less for electricity as a result. But other people in the system may subsequently face higher rates as a result of that overall adjustment in demand. And if their consumption has not fallen, they'll still be facing higher rates and they'll pay more.

[56] Appendix E 2013-2016 Power Smart Plan, page 41.

[57] An approximate current average customer rate for 2013/14 was calculated at $73,210/GW.h as total adjusted revenue at April 2013 rates ($134,563,726 and $136,076,017) for GS-ND and GS-D class respectively, divided by the Forecast Data 2013/14 Total kWh (1,632,178,221 kW.h and 2,064,602,134 kW.h). This data was taken from the 2012/13 and 2013/14 General Rate Application in response to MIPUG/MH I-20(b), which provided billing determinants for the Residential and General Service rate classes based on fiscal 2013/14 forecast data at April 1, 2012 rates, interim-approved September 1, 2012 rates (as per BO 117/12), and proposed April 1, 2013 rates at the time the IR was filed on October 3, 2012.

> The total -- the aggregate may have fallen for the entire group, but some people are going to be paying more than others, depending on their participation in the program (Tr: 7478).

This concept is part of the Rate Impact Measure test, as described by Mr. Bowman in CAC/MIPUG 7(b):

> The RIM test is a measure of the full financial impacts on the utility (costs incurred plus lost domestic revenue) as compared to the benefits (avoided investment or export revenues). At its core, the RIM test is measuring whether one group of customers is being made to pay excessive amounts to secure savings for a different group of customers, a blatant cross-subsidization. The key principle was outlined in comments made by Stan Wise, a former Chairman of the National Association of Regulatory Utility Commissioners (NARUC):
>
>> When a DSM program fails the RIM test it means that customers who do not participate in a DSM program will be forced to subsidize customers who participate in the DSM program. Using an example of additional attic insulation as a DSM program, some reasons why customers may not participate in the DSM program include: 1) some low income customers can't afford to participate if they have to pay a portion of the cost of the attic insulation (even if the utility pays a rebate equal to 75% of the cost of the attic insulation the customer may not be able to afford the other 25%), 2) some customers may have paid the full cost of additional attic insulation prior to the inception of the DSM program so they cannot take advantage of the DSM program yet are forced to pay higher rates so that those who have not taken such action can add attic insulation in the future at a fraction of the cost in which this customer added their own attic insulation, 3) a customer may realize that they will be moving within the next few years and that they will not get a payback on any out of pocket costs associated with adding attic insulation to the house they will soon be selling (the amount of attic insulation is not a primary consideration for most people shopping for homes and therefore they generally won't pay any extra to the seller for additional attic insulation), 4) the customer may simply choose to not take any action because of a busy life or prioritizing other activities ahead of calling the utility to register for the program and then taking a day of vacation to meet an attic insulation contractor at their home on the

> day of the installation. When a DSM program fails the RIM test, customers who cannot or choose not to participate in the DSM program subsidize other customers who do participate in DSM programs, regardless of the reason for not participating in the DSM program[58].

> Overall, the principles are the same – Hydro should be seeking to secure power resources that are economic for the utility and its customers (including those that do not participate) and should not be rejected viable options because Hydro has second guessed the customer's motivations.

This conclusion was further supported by Hydro's evidence in Exhibits MH-104, as noted by Mr. Bowman:

> The largest factor of concern in DSM scenarios is the lost domestic revenue. This underlines the importance of continuing to track this impact on Hydro and non-participating customers through variables such as the RIM and PACT tests (Exhibit MIPUG-9-4, page 1-7).

[58] Presentation to the Southeast Energy Efficiency Meeting (part of the Regional Implementation Meetings of the Clean Energy Program of the US EPA), September 28, 2007 by Stan Wise, Commissioner of the Georgia Public Service Commission. http://www.epa.gov/cleanenergy/documents/suca/se-sep-07_wise.pdf . As quoted in the response to CAC/MIPUG 7(b).

17) Have Risks been Properly Addressed?

All of the Plans entail risks. This includes not only risks related to actions taken, but similarly lost benefits of plans not taken. This was summarized in a quote from Dr. Magee in the 2010 GRA (repeated in Exhibit MIPUG- 24, page 10):

> 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.[59]

In either event it is ratepayers that bear the risks.

Hydro's approach to measuring risks, in the form of the quilt and P10/P90 ranges, is appropriate subject to the earlier comments regarding economic inputs and analytical issues in Section 5 & 6 above.

As to the conclusions, under Plan 1 (All Gas) the risks to ratepayers of gas prices become large and dominant as load grows. Under opportunity-based plans the risks tend towards export prices and interest rates. Each of these has significant impacts on level of rates, but has relatively small impacts on the government charges. For example, the Pre-Filed Testimony of Mr. Bowman shows the range of impacts to ratepayers and government for Plan 6 under the original assumptions[60]:

- Ratepayer benefits NPV expected value of $0.557 billion; P10/P90 range of negative $0.524 billion to positive $1.760 billion. Interdecile range of $2.284 billion (a measure of risk).

- Government benefits of NPV expected value $1.729 billion; P10/P90 values of $1.171 billion to $2.211 billion; interdecile range of $1.040 billion.

In short, under the original assumptions for Plan 6 (the same as Plan 5 but without the WPS 308 MW export contract) the NPV benefit to ratepayers was less than a third of the

[59] Dr. Magee, Transcript page 6123-6124; Hydro 2010/11 and 2011/12 GRA; as repeated in Exhibit MIPUG-24, slide 10.

[60] MIPUG-9-2, Pre-filed Testimony of P. Bowman, Revised February 28, 2014, page 4-6

benefit to Government, and the risk (measured by way of interdecile range) was more than two times as large. This was before the Keeyask cost escalation and increased P10/P90 range with the 2013 update, which would serve to decrease the benefit to customers, increase their interdecile range, and at the same time increase the benefit to government (through added capital taxes and debt guarantee fees on the larger plant). In short, the sharing approach as it is currently proposed is in inadequate.

On the matter of the context of ratepayer's current robustness to rate impacts, this topic was addressed at length in respect of both low income customers, and commercial/industrial customers. Dave Forsyth, Regional Energy Manager for Gerdau noted the following:

> MR: DAVID FORSYTH: Manitoba energy rates have increased substantially since 2004. As Mr. Turner said, the rates are up over 40 percent in that ten (10) year period. Industrial customers in Manitoba have been paying 10 percent more than the cost to serve them. Now we are told rates could be rising anywhere from 51 to 114 percent in the next eighteen (18) years, and a major factor in this is a choice of development plan.
>
> Ten (10) years ago, Manitoba Hydro probably offered the lowest industrial rates in North America. There is a myth in Manitoba that electricity rates are still the lowest in North America. This is not the case when you consider the all-in costs of delivered electricity, including optional programs that are available in other jurisdictions.
>
> …
>
> We're always concerned when utilities, such as Manitoba Hydro, propose to take on big risk on behalf of the ratepayers with projects that require a long lead time to satisfy load or contracts that are predicted to show up decades away. If this turns out to be overbuilding or the major assumptions turn out to be wrong, it could result in cost skyrocketing for existing customers. These costs would be in addition to the possible 51 to 114 percent increase (Tr: 7213 – 7217).

The current context for decisions takes place against this backdrop – high rate increases, reducing competitiveness of Manitoba rates, limited options to control power costs, constraints imposed by Hydro on one of the few options that exists (the Curtailable Service Program) and risks and benefits that are poorly distributed between ratepayers and government.

Regardless as to the conclusions on which precise plan to take, or how to view future commitments, there is a clear need to address the issue of risk and benefit sharing. This is needed not just for Conawapa, as addressed by Mr. Bowman, where a failure to achieve appropriate revised risk sharing with government will eliminate Conawapa from consideration as a project that in any way benefits ratepayers. But this same benefit sharing is needed for Keeyask, if advanced to 2019, and the 750 MW line. The realignment of benefits is not a requirement to allow the projects to proceed – it is however a practical requirement in order to achieve fair sharing of benefits, appropriate benefit vs. risk balance (ratepayers take effectively all risks – benefits should largely follow), and to help offset the current pressures from projects outside the PDP (Bipole III, aging asset reinvestment, etc.).

18) Does the Plan Extend Hydraulic Generation so as to Increase Hydro's Exposure to Drought Risk?

In terms of adverse impacts, the largest expected financial impact from Hydro's hydraulically based system is from drought.

> MS. LIZ CARRIERE: … Sufficient retained earnings is critical to Manitoba Hydro's to be -- to absorb the financial impacts of adverse events for a short period of time in order to provide some protection to ratepayers. One (1) of those events that we'll be looking at is drought.
>
> It's known to be one (1) of Hydro's highest impact -- or a high-impact risk with a high probability of occurrence, and this analysis analyzes the recurrence of one (1) of the worst droughts on record, or the lowest extended period of low water flows. Because Hydro's system is predom -- or the -- predominantly is a hydro-based system, this risk exists regardless of the development plan that we choose (Tr: 2813 – 2814).

Hydro's evidence is that the Opportunity-based plans decrease drought risk in later years, largely due to increased retained earnings projections. This is poor circular reasoning. The basis for ratepayers putting aside reserves by way of retained earnings is to provide themselves with cushions for future events that would otherwise cause rate instability. The metric should not be based on whether ratepayers have over-invested in retained earnings (which occurs under Hydro's PDP analysis) but rather what are the total dollar value effects of a drought under each of the plans. Mr. Bowman explained the difficulty of this approach to setting retained earnings targets:

> MR. PATRICK BOWMAN**:** Because your net income varies [when comparing plans], you actually have no more drought risk by going with Plan 14 under the original scenarios than you would under Plan 1 All Gas, because you've just built a bigger system, your one point two (1.2) interest coverage is higher, you're targeting a higher overall net income. So when the drought hits, it knocks you back a little bit further, but you don't end any worse in terms of your net loss (Tr: 10299 – 10300).

The actual dollar value of drought impacts under three energy price alternatives were provided in Exhibit MIPUG-9-4 Table 1, as follows:

Table 1: Fiscal Year 2034/35 Net Revenue (Millions of 2014 Dollars) – 5 Year Drought[61]

	Drought Risk ($ Millions)			Extra Drought Risk Comparing Plans ($ Millions)		
Energy Price	Plan 1	Plan 5 (6)	Plan 14 (PDP)	Plan 5 - Plan 1	Plan 14 - Plan 5	Plan 14 - Plan 1
Total Low	(1,220.2)	(1,289.7)	(1,414.3)	(69.5)	(124.5)	(194.1)
Total Ref	(2,014.6)	(2,195.7)	(2,437.6)	(181.1)	(241.9)	(423.0)
Total High	(2,909.0)	(3,217.3)	(3,567.8)	(308.3)	(350.5)	(658.8)

The analysis in the Table above indicates that the net negative impact of a five-year drought (in the period around 2034/35) varies by the assumed energy price (export price, price of gas). Under low prices, the effects of proceeding from Plan 1 (All Gas) to Plan 5 (Keeyask 2019, Gas, 750 MW Interconnection) is only $124.5 million, over 5 years. This is a net negative impact on net income averaging only $25 million per year. Similar impacts are shown for reference and high export prices – the Plan 5 drought increment over Plan 1 is surprisingly small (no more than $70 million per year on average at high export prices).

Plan 14 (PDP) starts to show larger effects of drought due to Conawapa. However note that even under high export prices, the total drought risk to Hydro with the PDP peaks at $3.568 billion. This is a net negative impact on income – if there were an assumed $200 million net income during the period at average flows (totaling $1 billion over 5 years) the actual net loss due to the drought would be $2.5 billion. This is in stark contrast to all rate design scenarios provided by Hydro to date, which all target retained earnings in the range of $4 to $9 billion by this point in time (per Exhibit MH-104-12-6 as at 2031/32).

Therefore, the retained earnings sought under the current forecast methodology is more than double the amount needed to cover the worst five year drought on record with no additional rate implications.

[61] From MIPUG-20-4: MIPUG Book of Documents for the MH Economic Panel, March 12-13, 2014. Tab 9a, page 47. Calculated from MIPUG/MH I-007(a) from the NFAT Hearing.

19) Is it Possible to Revise the Import Criteria in a Manner that Helps Avoid the need for the PDP?

It is possible for Hydro to revise the import criteria, as it is solely a policy decision not a physical constraint. However, it is not clear that any such revision is advisable or, if in practice it would lead to a different choice of development plans.

First, it is important to recognize that there are three different approaches to setting an import standard:

1) **When to build?:** The first relates to determining when new resources are needed. This aspect of the criteria says that imports cannot exceed the lesser of (a) the maximum tie-lie capacity during off-peak hours, or (b) 10% of the Manitoba peak plus 100% of firm exports[62]. Revising this criteria (i.e., relieving the constraint) results in a direct effect on the security of supply to Manitobans. The response to CAC/MH I-051 notes that Hydro documented a clarification to its energy import criteria in September 2013, which had the effect of substantially increasing the quantity of imports that could be relied upon compared to the criteria relied upon in past decades (see for example, page 26 of the "Review of Generation Planning Criteria" in Attachment CAC/MH I-051). Also of note, MIPUG/MH I-041(c) shows that the main criteria under almost all future scenarios is in fact the off-peak import limit criteria, not the 10% of Manitoba load criteria.

   Mr. Bowman provided testimony on the risks associated with this criteria:

   > MR. PATRICK BOWMAN**:** In making that decision about, When do I need to build, under most of the scenarios you will see in front of you, it is not the 10 percent of Manitoba load criteria that is being triggered. It is the off- peak criteria that's being triggered. Hydro has already assumed, in terms of deciding when it needs to build and when it has enough energy, that it has maximized the imports off peak, plus the export load. Or, sorry, I apologize, just to maximize the off peak.
   >
   > And I would strongly recommend that that criteria not be departed from lightly, if at all, because yielding on that criteria is the decision about the lights going out. It's a decision -- and not for

[62] NFAT Business Case, Chapter 4 page 38.

> short periods of time. It's a decision about not having enough power for an entire winter. (Tr: 10121-10122)

2) **What to build?:** In comparing the economics of the various plans, Hydro prepares forecasts based on an assumed use of imports that is different than approach #1 above. The intent of the "production costing" analysis is different than determining the date of need and energy/capacity shortfalls. The production costing run is intended to represent how the assets constructed will actually perform in Hydro's system. For the purposes of this analysis, the strict criteria from #1 above is relieved by 1,100 GW.h – this permits far more exports assumed to be available on average than the worst (or near worst) case scenario analyzed under approach #1. The intent of this criterion is that it reasonably represents what will occur on average in actual operating conditions.

3) **Actual operation:** Under operating conditions, Hydro will import whatever economic energy is available, regardless as to the planning criteria applied in approaches #1 and #2 above. This still requires consideration of export prices, as well as system stability as noted in MH Rebuttal Evidence, Exhibit MH-85-2 page 22 (Hydro cannot rely on imports to a scale that would drive Manitoba domestic generation and transmission loading to a low level which threatens system stability).

LCA has recommended a revision to the import criteria that relieves to some degree the constraints on both approaches #1 and #2 above. MIPUG does not support any revision to criteria #1 without a detailed and thorough consideration of the risks to Manitoba customers from such revision, as well as the cost implications. In regards to possible changes to the import criteria, particularly #1 above, Mr. Bowman noted:

> MR. PATRICK BOWMAN: I'm going to try to do a small job on this. If you're interested in it, I encourage you to follow up with Hydro with it because it's a lot more complicated than the record reflects (Tr: 10121).

Given that Hydro's evidence supports advancing Keeyask prior to the date where the above criteria would be triggered; there is no need today to make hasty decisions on this matter.

In respect of #2 above, the criteria is used to help determine which plants to build. The analysis should consider the import criteria as a possible sensitivity. That is, in coming to a decision about the best resource plan, Hydro should confirm that modest revisions to the expected level of imports do not result in changed conclusions regarding which plan or pathway is preferred. This information should be made available for future resource plan reviews.