PRE-FILED TESTIMONY OF
PATRICK BOWMAN
IN REGARD TO MANITOBA HYDRO
2019/20 ELECTRIC RATE APPLICATION

Submitted to:

The Manitoba Public Utilities Board

on behalf of

Manitoba Industrial Power Users Group

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March 29, 2019

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1.0 INTRODUCTION

This Pre-filed Testimony has been prepared for the Manitoba Industrial Power Users Group ("MIPUG") by InterGroup Consultants Ltd. ("InterGroup") under the direction of Mr. Patrick Bowman. The qualifications of Mr. Bowman are provided in Attachment A.

For this Pre-Filed Testimony, InterGroup has been asked to identify and evaluate issues arising from Manitoba Hydro's ("Hydro" or "MH") one-year Electric Rate Application for 2019/20 ("ERA" or "Application").

Hydro's current Application follows an extensive proceeding in the 2017/18 and 2018/19 General Rate Application, and it is anticipated that a General Rate Application will be filed later in 2019 for the 2020/21 and 2021/22 fiscal years.

The circumstances and scope for this proceeding are unique and this has shaped the review and testing undertaken in this Pre-Filed Testimony, discussed further in Section 2.0.

1.1 SUMMARY OF CONCLUSIONS

Hydro's requested 3.50% rate increase for 2019/20 is generally consistent with exhibits prepared in the previous proceeding (the 2017/18 and 2018/19 GRA) namely Exhibit MH-93, which the PUB described as "directionally consistent with the Board's decisions in this Order" in Decision 59/18.[1]

However, significant revisions in Hydro's forecast costs and loads now indicate that no rate increase for 2019/20 is required to achieve the targeted net income from Exhibit MH-93.

Prior to addressing these specific matters, **Section 2** of this submission sets out comments on the basis for review of Hydro's ERA. The approach to determining whether rates are just and reasonable for this proceeding is challenging, as Hydro rates have always been set based on testing if customers were sufficiently contributing to reserves (i.e., the forecast level of net income) to maintain the ability to secure a high likelihood of future rate stability on a long-term basis. In this proceeding, Hydro has not provided long-term forecasts to support this assessment.

Without a detailed understanding for the long-term financial considerations and risks to help guide the level that ratepayers should pay today, there is no empirical or sensible way to assess Hydro's proposal on a one-year basis. For this reason, the submission addresses both the one-year facts as presented, and the updated directional information about long-term cost levels.

[1] PUB Order 59-18, page 173.

Section 3 of this submission reviews Hydro's present filing in light of comparisons to Exhibit MH-93. For the 2019/20 forecast year, Hydro's net income of $65 million prior to any rate adjustments is higher than the $62 million forecast in MH-93 (which included an assumed rate increase).

Further, although Hydro has framed the current application as focusing solely on 2019/20 and not beyond, there are multiple significant new facts which indicate Hydro is likely to outperform the long-term scenario in MH-93, even with lower rate increases than assumed in that scenario. This includes the following facts, each of which is addressed in this submission:

- Long-term interest rates are well below the levels assumed in preparing MH-93, which will have an enduring benefit to Hydro's long-term costs. For example, long-term interest rates have been lower than the rates incorporated in MH-93 for 2018/19 by an average of 0.5%. Hydro is nearing completion of its peak debt borrowing year (2018/19) to fund Major New Generation & Transmission (MNG&T) projects. While interest expense is not lower than forecast in 2019/20, this is due to the inability to borrow at short-term rates for the same low interest rate assumed in MH-93, but this effect is transient during the period up to five years; the long-term borrowings (e.g., 30 years) are of far greater importance in determining the long-term rate trajectory required. (see section 3.1);
- DSM spending has not been adjusted downwards to reflect lower marginal values, nor to reflect the purpose nor focus of Efficiency Manitoba to target cost-effective DSM and lowered carbon emissions (section 3.2);
- Bipole III is now known to be in-service at a materially lower cost than originally budgeted, and Keeyask remains on track to meet budget, with the majority of project costs now locked in (64%) and a significant part of the remaining costs likely being tied to interest expense rather than direct project costs. As a result, both the cost profile and the risk profile of the major capital projects are significantly improved (section 3.3); and
- The PUB noted that export revenues in MH-93 failed to include any amounts for capacity sales or any premium values for selling future dependable energy (all future sales were assumed to be only as short-term interruptible energy, even where the energy was dependable). For this reason, MH-93 fails to fully include the prospect for future export revenues, which will reduce the amounts that need to be paid by domestic customers (section 3.4).

Notwithstanding that a zero percent rate increase would still be expected to achieve the MH-93 net income for 2019/20, and the long-term results likely look significantly improved as compared to MH-93, there remains a potential basis to impose a small inflationary increase to customers today (**section 4**). This reflects that there is a likely need to transition rates to a higher level as Keeyask comes into service, and the preferred approach to increasing customers rates is on a stable and predictable basis. Should the Board elect to impose a rate increase of no more than 1.5% as an inflationary adjustment, the Board should direct that any such revenue be targeted to a deferral account or transition fund to address MMTP and Keeyask coming into service.

2.0 BACKGROUND AND SCOPE

2.1 BACKGROUND

Hydro's Application filed November 30, 2018 requested a final rate increase of 3.50% through an expedited process. Unlike a GRA, or indeed even recent examples of interim rate applications, the expedited process was to include no long-term information on Hydro's financial forecasts (the Integrated Financial Forecast document or "IFF") nor consideration of various cost items that extend beyond the 2019/20 fiscal year. Hydro's rate increase request was originally set at a level "sufficient to generate a minimum level of net income such that Hydro would avoid a projected net loss in the 2019/20 fiscal year."[2] Hydro's justification for limiting the scope of the review to exclude all long-term financial forecasts was that Hydro's new Board of Directors ("MHEB") was undertaking a comprehensive financial review of the Corporation. Hydro also did not provide a fully allocated cost of service study, nor responses to a large number of directives issued by the PUB in the previous GRA.

The original Application filed November 30, 2018 was not only limited in scope compared to a GRA, it was also based on dated financial information. Hydro requested the 2019/20 rate increase be based solely on the 2019/20 Interim Budget and Planning Assumptions which was dated from October 26, 2018.[3] This included such dated assumptions as those underlying the 2017 Load Forecast (updated only for 2017/18 actuals),[4] the 2017 (fall) Energy Price Forecast,[5] December 2017 key interest and exchange rate forecasts,[6] fall 2017 assumptions for Capital Expenditures,[7] and included no detailed Operating and Administration budgets as these were said to be unavailable.[8]

The basic rationale provided by Hydro in the ERA was as follows:

[2] Hydro correspondence to the Public Utilities Board dated November 12, 2018 re: Manitoba Hydro – Proposed 2019/20 General Rate Application
[3] Hydro letter to PUB November 12, 2018 letter to the PUB, page 5.
[4] Hydro November 30, 2018 Application, page 20 of 43
[5] Hydro November 30, 2018 Application, page 23 of 43
[6] Hydro December 11, 2018 Application Additional Information, Attachment 5, pdf page 16 of 55
[7] Hydro letter to PUB November 12, 2018 letter to the PUB, page 5.
[8] Hydro November 30, 2018 Application, page 28 of 43

> Manitoba Hydro is requesting approval of a 3.5% rate increase to be effective April 1, 2019. This increase is projected to generate additional revenues of approximately $59 million and would result in a modest net income of $31 million in 2019/20. Absent the proposed rate increase for 2019/20, Manitoba Hydro is projecting a net loss of $28 million from Electric operations.[9]

Hydro provided updated financial information for the 2018/19 Current Outlook and 2019/20 Approved Budget following approval by the MHEB on February 14, 2019. The Supplement Application reflects actual financial results and water conditions to December 31, 2018, as well as updated planning assumptions for the following:

- 2018/19 and 2019/20 projected capital expenditures, incorporating the revised projected costs for Bipole III of $4.77 billion (from $5.04 billion);
- Updated Load Forecast assumptions, which incorporates the impacts of the 3.6% electric rate increase in 2018;
- Short-term forecast of export prices at December 31, 2018;
- Preliminary projections for 2019/20 DSM expenditures and revised planned savings, which reflect the delayed implementation of the Conservation Rates and the Fuel Choice initiatives; and
- December 2018 consensus forecast of interest and U.S. exchange rates.[10]

These updated forecasts reflect significant projected financial benefit in the 2018/19 and 2019/20 years. However, Manitoba Hydro's Supplement Application "submits that the 3.5% proposed rate increase continues to be necessary and in the public interest" and that:

> The proposed 3.5% rate increase continues to allow Manitoba Hydro to plan for a modest level of net income in the event of low water flow conditions. Waiting until low water flows occur and providing rate relief after the fact would result in permanent incremental debt and associated financing costs that must be passed through to customers. Further, given the increase in costs attributable to the in-service of Bipole III as well as the anticipated additional net costs associated with the in-service of Keeyask, a financial loss in 2019/20 could result in the exacerbation of financial losses projected in Exhibit 93 and the requirement for significantly higher rate increases in the period following Keeyask in-service.

[9] Hydro November 30, 2018 Application, page 24 of 43
[10] MIPUG/MH I-9a-c

Granting a 3.5% rate increase as requested in this Application reduces the likelihood of future rate shock to ratepayers.[11]

2.2 SCOPE OF REVIEW

The basis of review for the present application is challenging. This arises because, for each rate review going back to the late 1980s, Hydro has presented a long-term financial forecast to guide the rate setting process. The establishment of just and reasonable rates for Hydro has therefore always been considered in light of long-term financial targets (even though, as reviewed in detail in the evidence of Osler and Forrest in the previous GRA, the specific targets have evolved to some degree since the late 1980s).

The benefit of this form of regulation, as opposed to a strict rate-base/rate-of-return form of regulation, is a better ability to focus on rate stability and measured rate transitions, and on the role and importance of Hydro's customer-funded reserves in this regard. Under a rate-base/rate-of-return regulatory model, the rates for a single year can be set without regard to any future financial forecasts since it is typically required (including by legislation) that the utility investor be provided an opportunity to earn a fair return on their equity each and every year. In the case of Manitoba Hydro, the utility "investor" is the collective customers, who have provided all of Hydro's booked "equity" by contributing to reserves that are intended to provide for future rate stability (and not to earn for customers any form of "return" on their contributions to reserves).

In short, the test for Hydro in each previous GRA was whether, in the year in question, customers were sufficiently contributing to reserves (i.e., the forecast level of net income) to maintain the ability to secure a high likelihood of future rate stability. If not, a level of rate increase was determined to increase contributions. Long-term forecasts of reserve levels were reviewed in light of the cost of future risks from drought, infrastructure reinvestment, etc. The specific art of setting one-year rate increases was somewhat akin to driving on a highway – look far down the road and make small adjustments to generally maintain the course within your lane in a manner that is not jarring, and that will achieve the appropriate course over the long-term (unless headed for the ditch – then rapid adjustments may be necessary).

In light of this approach to review, there is no overwhelming or compelling evidence supporting a need for rate increases simply because Hydro has a net income at any given level in a particular year (even a negative net income). Consider the Board's Decision in Order 25-92, where Hydro was forecasting a negative net income despite a 3.5% proposed rate increase. The PUB cut the rate increase requested to 2.65% even though this exacerbated the forecast net loss, and despite the fact that Hydro had less retained

[11] Supplement to the 2019/20 Electric Rate Application, February 14, 2019, page 3 of 16

earnings than the calculated cost of a 2-year drought at that time.[12] This was justified on the basis that Hydro continued to show IFF forecasts that made progress towards the then-established financial targets.[13] The recent GRA reviewed similar considerations in Exhibit MH-93, which the Board described as follows:

> In many respects, and as a departure from Manitoba Hydro's plan and Integrated Financial Forecast assumptions, Manitoba Hydro Exhibit 93 is therefore reflective of many of the Board's decisions in this Order. [14]
>
> Beginning in the Test Year, the Manitoba Hydro Exhibit 93 Integrated Financial Forecast scenario results in equal annual rate increases of 3.57%. The Board finds that with minor adjustments, this scenario is directionally consistent with the Board's decisions in this Order.[15]

It should be noted that MH-93 shows 6 years of net losses following the implementation of Keeyask, from 2023-2028.[16] Acknowledging that the PUB did not issue any approvals for rates from 2023-2028 as yet, it is consistent with the data from 1992 and 2017 that some period of net losses is not, in and of itself, evidence that rates are unjust or unreasonable.

To maintain the earlier driving analogy, negative net income is not in and of itself evidence of heading towards a ditch.

The dangers of setting Hydro's rates without relevant information about long-term forecasts or needed reserve levels is that simple comments or projections can be substituted for appropriate rate analysis. Consider Hydro's comments in its February 14, 2019 submission, after if became clear that Hydro could not sustain a case for a 3.5% increase simply on the basis of avoiding net losses. In that submission, Hydro elected to rely on three notional points of justification, none of which bear out as reasonable under even simple scrutiny, as follows: [17]

- Hydro indicates: *"Waiting until low water flows occur and providing rate relief after the fact would result in permanent incremental debt and associated financing costs that must be passed through to customers."* This statement is a gross misrepresentation of the concept of ratepayer-funded reserves. Since the late 1980s, when Hydro operated with very little reserves, ratepayers have funded increases in reserves to a forecast level of $2.862 billion by year-end 2018/19. This

[12] Along with the cost of the maximum self-insurance loss. PUB Order 25-92, page 12.
[13] PUB Order 25-92, page 12.
[14] PUB Order 59-18, page 173.
[15] PUB Order 59-18, page 173.
[16] Exhibit MH-93 from the Manitoba Hydro 2017/2018 and 2018/19 GRA
[17] Supplement to the 2019/20 Electric Rate Application, February 14, 2019, page 3 of 16

compares to a current analysis of the worst single-year drought which has a negative $347 million negative impact (based on the 1940 year hydraulic energy generation levels) as provided in MIPUG/MH I-4a-b[18] (where "impact" is the reduction of net income, such that if a positive net income was otherwise assumed, the true net loss during the drought would otherwise be lower than this value). In short, the idea that customers need to pay more in current rates for this one year because otherwise Hydro would have to seek future rate relief, when reserves of more than $2.862 billion have been accrued, is inconsistent with the facts.

- Hydro also indicates: *"Further, given the increase in costs attributable to the in-service of Bipole III as well as the anticipated additional net costs associated with the in-service of Keeyask, a financial loss in 2019/20 could result in the exacerbation of financial losses projected in Exhibit 93 and the requirement for significantly higher rate increases in the period following Keeyask in-service."* This statement is also curious given that Exhibit 93 already assumed Bipole III and Keeyask were coming into service. The specific reference to "increase in costs" is particularly odd, given Bipole III has in fact come in at a cost much LOWER than assumed in Exhibit 93, not higher. Further, the evidence on Keeyask has taken a far more optimistic tone, and each passing month the uncertainty with respect to costs is reduced as more and more costs are locked in and at financing rates lower than forecast. It is obviously always potentially true that unexpected risks could emerge, but the evidence appears to run counter to this justification for the increase.

- Finally, Hydro notes: *"Granting a 3.5% rate increase as requested in this Application reduces the likelihood of future rate shock to ratepayers."* As above, this statement appears to be nothing more than a directional statement of a mathematical relationship. The same could be said of any rate increase, of any magnitude. It provides no assessment of how likely a future rate shock to customers presently is, how much this would be reduced by a 3.5% rate increase, or why the same rationale would not support a 0.35% increase or a 35% increase. In short, this does not provide support in any way the level of rate increase being proposed by Hydro.

If anything, the more recent Hydro rate reviews have increased the importance and relevance of long-term projections for rate setting as compared to the earlier reviews. During most GRAs dating back to the late 1980s, it was always possible to consider long-term targets, which were universally agreed should target an increase in retained earnings levels; the core debate was how fast to achieve the added reserves, and how would other factors unfold (such as O&M costs). This was in part tied to large growth in assets, and large growth in the estimated exposure to costs of drought. Consider the following:

[18] Impact of drought for 1940, per the "Variation of Net Revenue from Average" column.

- In 2003 (IFF MH01-1), domestic revenues were forecast at $796 million (2002/03), while export revenues were $537 million (60% domestic, 40% export). A five-year drought[19] had a net cost of approximately $1.2 billion at a time when reserves were at $1.29 billion.[20] In that situation, financial risk of exposure to export markets were high (as it consisted of 40% of revenues) and drought costs approximated the level of reserves, such that a five-year drought could wipe out all retained earnings. Further, any downward revision in export prices (which had only recently risen to record levels) would be a material hit to net income and require additional rate increases.
- By 2009 (IFF09-1), domestic revenues were forecast at $1.160 billion (2009/10), while export revenues were $414 million (74% domestic, 26% export). A five-year drought had a net cost of approximately $2.405 billion[21] at a time when reserves were at $2.183 billion.[22] In that situation, risks from exposure to export markets had somewhat declined (as it consisted of only 26% of revenues, compared to 40% in 2003) but drought costs still exceeded the level of reserves.
- As of the previous GRA, Hydro Exhibit 93 for 2017/2018 showed domestic revenues forecast at $1.615 billion, while export revenues were $514 million (76% domestic, 24% export). A five-year drought had seen a drop in net cost to approximately $1.218 billion[23] at a time when reserves were at $2.749 billion.[24] In that situation, risks from exposure to export markets continued to decline (as it consisted of 24% of revenues) and reserve levels now exceeded drought costs. Actual domestic revenue to extraprovincial revenue for 2017/18 was $1.616 billion to $437 million (79% domestic, 21% export).[25] This reflects a material new reality compared to the earlier reviews, where parties can begin to consider whether the level of customer reserves had reached a level that could be maintained stable, rather than simply perpetually increased.

By this last GRA, and into the near future, it becomes increasingly an item of debate as to when reserves have reached a sufficiently high level that there is little to no further benefit to customers to keep adding to reserves (through additional net income). When operating in a phase where reserves were being built up (such as from the 1980s to somewhere about 2015), each GRA can quickly conclude that, absent rate shock, rates should trend higher and net income should be positive each year to help build reserves. This is not where rates are today. With refinement of the more advanced probabilistic tools becoming available to Hydro and the PUB, the focus regarding building up reserves should begin to change. This is consistent

[19] The five-year 1987 to 1992 drought affects six fiscal years, which in IFF MH-01-1 had an assumed net income of $582 million without the drought, and a net loss of $635 million with the drought. This includes compounding interest expense.
[20] Year end 2001/02 per IFF MH01-1.
[21] IFF 09-1 page 20
[22] IFF 09-1 page 35
[23] MIPUG/MH I-18 from the Manitoba Hydro 2017/18 and 2018/19 GRA, Table 1
[24] Exhibit MH-93 from the Manitoba Hydro 2017/18 and 2018/19 GRA, pdf page 5 of 13
[25] Appendix 1 (Updated), Updated Financial Statements 2017-18 to 2019-20, pdf page 1 of 4

with discussion at the previous GRA that began to coalesce around increased risk modelling as to what might in future be required in terms of reserves to ensure rate stability (for example, the risk modelling in Appendix 4.2 from the 2017/18 GRA, Exhibit MIPUG-13 Mr. Bowman's evidence in the 2017/18 GRA, and particularly and MIPUG-15 – Supplemental Background Paper C). The Board also directed that there be further evolution in the long-term ratemaking framework through the intended Minimum Retained Earnings process (which was later cancelled for timing and process reasons).

In light of the above, it is submitted that there is no empirical or sensible way to assess Hydro's proposal absent some directional information about the long-term, particularly at the current levels of reserves. It is simply not determinative to a finding that rates are unjust or unreasonable for quantitative reasons that net income is $60 million, or negative $60 million, or any other specific value in a single year.

It is also not conceivable that a finding can be made about rates without reference to the standards required by the *The Crown Corporations Governance and Accountability Act*, including Section 25(4) which indicates a factor to be considered in the PUB's decision regarding the review of rates is appropriate collection of reserves, which is inherently a long-term consideration.

For this reason, this submission considers Hydro's present filing in light of comparisons to the most reasonable long-term benchmark available, Exhibit MH-93 from the previous GRA.

3.0 COMPARISON OF THE UPDATED ERA FORECAST TO EXHIBIT 93

Hydro provided the updated financial forecast for Electric Operations for years 2017/18 – 2019/20 in Appendix 1 (Updated). In that updated forecast, Hydro noted forecast net income for 2019/20 was $115 million when the 3.5% rate increase was included, which totaled $50 million of added revenue (assuming June 1, 2019 rate implementation), or approximately $64 million net income without a rate increase.[26] The level of net income absent a rate increase compares favourably to the targeted level of $61 million in 2019/20 per MH-93 from the previous GRA. In short, without a rate increase today, Manitoba Hydro is achieving the same net income as had been expected under the MH-93 scenario.

Other relevant comparators arise from elsewhere in the financial statements, as follows:

- **Debt Levels:** Hydro's debt, estimated as the sum of Long-Term Debt and Current and Other Liabilities, totals $25.625 billion in the latest forecast for 2019/20, compared to $26.205 billion in Exhibit MH-93. This $0.580 billion improvement is largely due to reduced net plant in service, from $17.506 billion in MH-93, to $16.963 billion in the updated forecast, an improvement of $0.543

[26] Supplement to the 2019/20 ERA February 14, 2019, page 12.

billion. Note that this reduced capital spending is from assets in service, not from Keeyask or other work-in-progress, which is largely unchanged ($7.522 billion for construction in progress in MH-93, versus $7.658 billion in the updated Appendix 1).

- **Retained Earnings and Drought Risk:** Retained Earnings are forecast at $2.977 billion for year-end 2019/20 under the updated forecast compared to $3.047 billion under the MH-93 forecast, an erosion of $0.077 billion (or $0.127 billion absent a rate increase in 2019/20). At the same time, the cost of the worst drought that could affect 2019/20 has been materially mitigated, given what is now known about water conditions. In MH-93, the 2019/20 year still had exposure to droughts that could adversely affect net income by up to $432 million[27] in a single year, while the updated information has a maximum total impact of $347 million[28]. The two graphs below show the range of exposure to 2019/20 flows for MH-93 and the updated information (102 historical flow years for MH-93 assumptions, compared to 105 historical flow years for the 2019/20 ERA forecast) highlighting the degree of exposure for this one-year short-term focused case has been significantly mitigated. There is no information in the filing regarding the updated assessment of a long-term drought case.

[27] Per PUB/MH-I 153d from the 2017/18 and 2018/19 GRA, reflecting the "Variation of Net Revenue from Average" column for 2004.
[28] Per MIPUG/MH 4a-b from the current ERA, reflecting the "Variation of Net Revenue from Average" column for 1940 flows.

Figure 1: Net Revenue Variation over 105 Historical Flow Years for 2019/20 (Based on Water Conditions to December 31, 2018 from MIPUG/MH I-4a-b) $ Millions

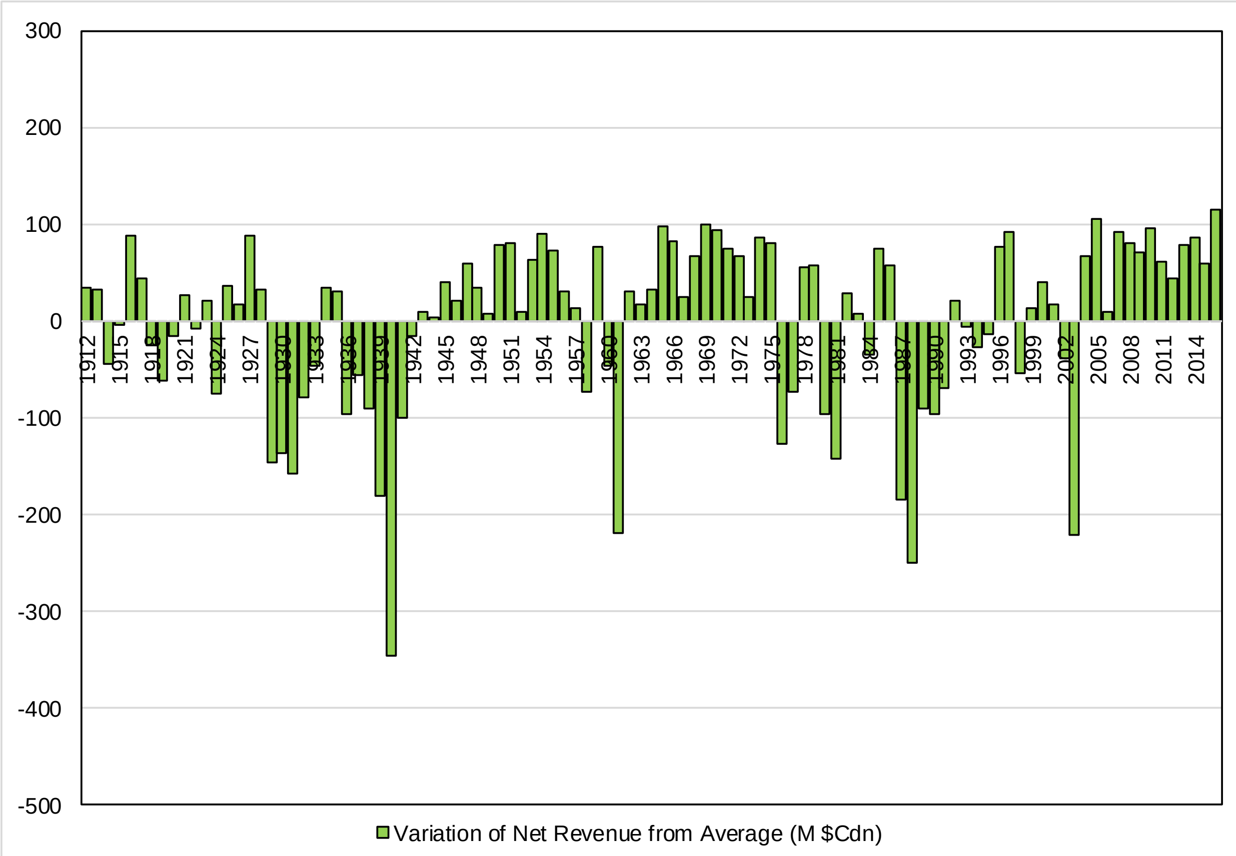


Figure 2: Net Revenue Variation over 102 Historical Flow Years from IFF16 for 2019/20 (Based on Water Conditions to 2013/14 from PUB/MH I-153d) $ Millions

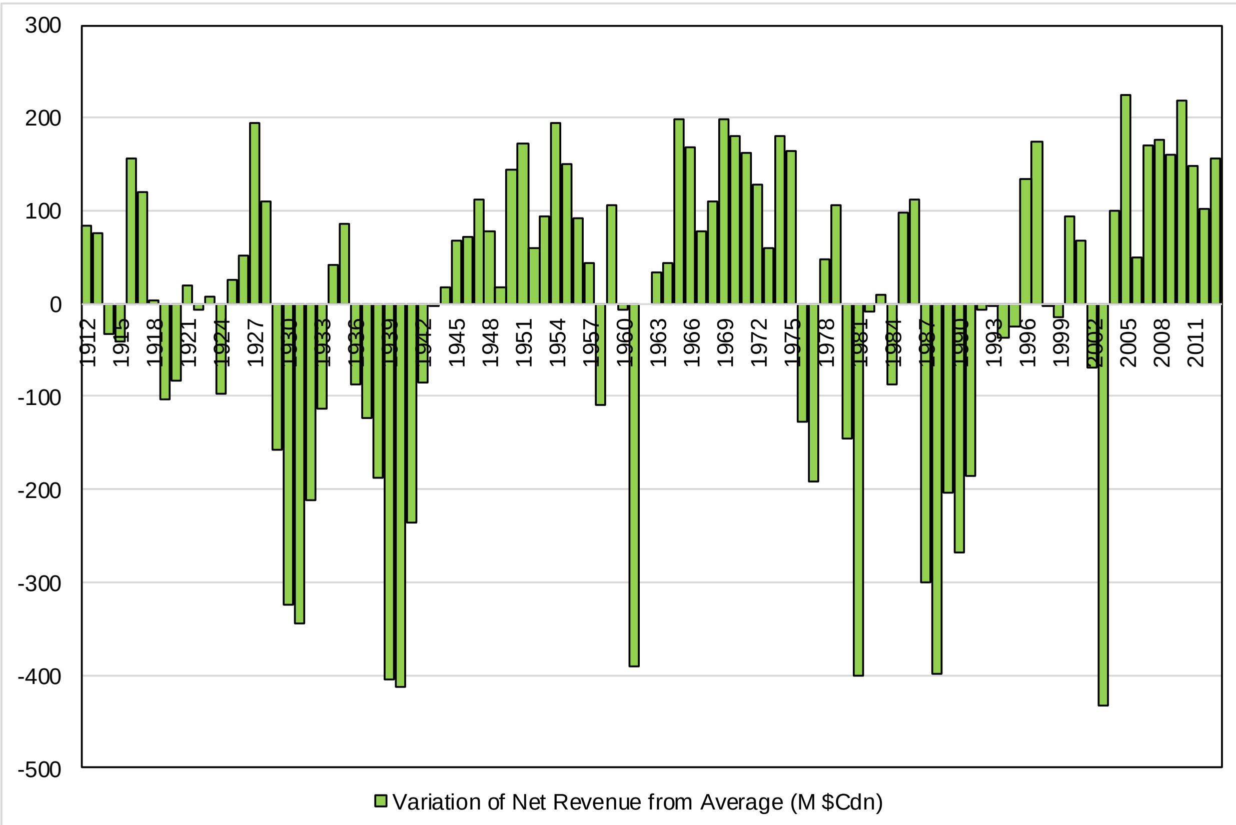


Figure 1 above, the current financial risk profile from Hydro's historical water flows, shows a markedly reduced revenue variation due to changes in water flows compared to Figure 2, from the 2017/18 GRA. Some of the reduced exposure also is likely due to the addition of 3 more years of historical record (from 102 years to 105 years) which has increased slightly the long-term average generation value.

- **Cash Flows:** In the previous GRA, Hydro asserted that operating activities did not generate sufficient cash to make routine re-investment in plant (i.e., normal capital spending). While MIPUG took issue with the concept that all normal capital spending should be financed with cash flow, rather than financed with debt repaid over the life of the asset in question as it was depreciated (particularly for clear system improvements), the full suite of information needed to assess this claim was not provided as part of MH-93. For the current forecast, this information is now available as part of MIPUG/MH-I-8c. The statements show a positive cash flow of $571 million in 2019/20 provided by operating activities, when the following standards are applied:

- Capitalized interest (e.g., interest on spending for capital projects such as Keeyask) is reported as an investing activity, consistent with the fact that the cost is a valid component of Hydro's capital spending. Note that Hydro's rationale for changing this cash flow classification to operating activities is to "provide readers of the financial statements with the total interest paid by the Corporation regardless of whether expensed or capitalized given the significance of the corporation's debt portfolio",[29] which is not relevant for rate setting nor for the regulatory 'used and useful' test (i.e., interest on debt borrowed to finance assets that are not used and useful should not be included in rate assessments); and

- Cash paid for mitigation activities and the City of Winnipeg payments tied to the purchase of Winnipeg Hydro is accounted for as an operating activity. While there may be concerns over the scope of the cash flows included in these definition (e.g., whether mitigation expenditures include amounts tied to development projects such as Keeyask), it would appear including these amounts as operating activities that consume cash is likely appropriate.

This $571 million in cash flow includes the $50 million assumed to arise from the proposed 3.50% rate increase on June 1, 2019. Even excluding the rate increase in full yields $521 million in cash flow, which compares favourably to the $510.5 million in Electric Business Operations Capital spending[30] per the ERA filing Appendix 6 (the Capital Expenditure Forecast, page 5). This cash flow situation indicates that the full normal capital spending is indeed able to be funded by operating cash flows, even before considering whether any of this normal capital spending is appropriately thought of as debt-financed, and apparently before consideration that a further $13 million of the capital spending will be funded by customer contributions (i.e., funded by customer cash not requiring internally generated funds).[31]

In short, on the metric of net income, the 2019/20 forecast compares favourably to Exhibit MH-93 even without any rate increase. On the metric of total debt, the updated 2019/20 forecast shows improvement over MH-93, as does the new forecast compared to MH-93 on the metric of restraining cumulative capital spending. Finally, on the topic of cash flows, it is not possible to draw a numerical comparison to MH-93, but the updated cash flow information indicates that even without a rate increase, Hydro is able to internally finance all normal capital spending (and then some) from Operating Activities, which Hydro asserted in the

[29] PUB/MH I-4b
[30] The Electric Business Operations Capital expenditures includes both sustainment projects and business operation support projects for generation and transmission; sustainment, capacity and growth and programs for distribution; and programs and business operations support projects for the corporate infrastructure asset category
[31] Per MIPUG.MH I-8c

previous GRA was at that time not possible. Each of these are achieved even assuming no rate increase for 2019/20.

The only metric on which Hydro shows some erosion is the cumulative Retained Earnings. Absent a rate increase today, the retained earnings at March 31, 2020 is projected to be $0.127 billion lower than forecast in MH-93. However, this is matched with a reduction in drought exposure over the only period where such data is available (2019/20). Further analysis will be required at the next full GRA to confirm if this level of retained earnings is indeed a reduced ability of ratepayer-funded reserves to fulfill their intended purpose to help stabilize rates over the long-term during periods of risk.

While the above factors show a comparison of the 2019/20 specific metrics from Exhibit MH-93 to the present ERA forecast, there are also longer-term trends or indications regarding MH-93 that should also be considered as a directional indicator of the likely status of today's forecasts versus MH-93. These include the following, as addressed in the following sections:

3.1) **Long-term Interest Rates** which suggest MH-93 interest costs are likely overstated in the long-term based on what is now known.

3.2) **Demand Side Management** which is set at a level in MH-93 that is above what can likely be justified given the updated marginal values, and the scope and focus on Efficiency Manitoba to pursue cost-effective DSM and mitigate rate impacts.

3.3) **Impacts of Bipole III Costs and Keeyask Forecasts** are material to the long-term forecast. Bipole III costs are now known to be materially below budget, affecting the long-term forecasts in MH-93 positively. Keeyask costs remain on-budget compared to that assumed in MH-93, with ever decreasing cost risk as more and more costs are locked-in as actuals.

3.4) **Capacity Values and Dependability Premiums on Export Sales** which are a source of revenue that was not included in MH-93.

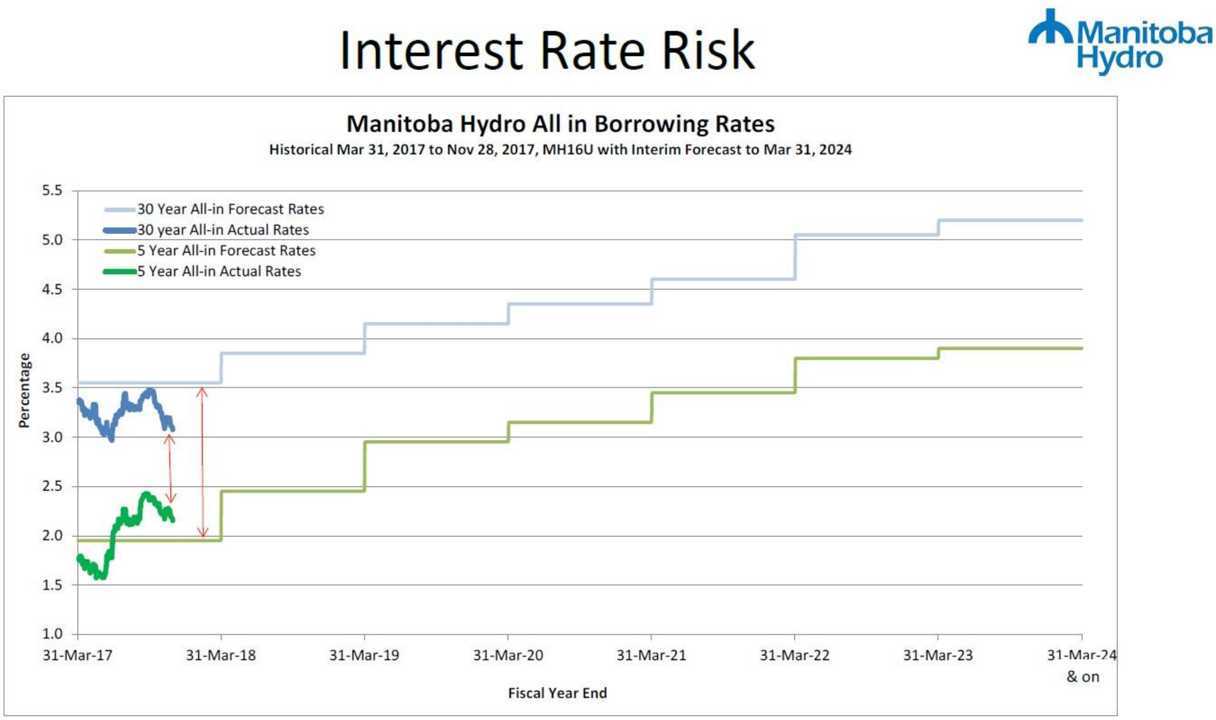
Each of these factors is addressed in the materials that follow.

3.1 LONG-TERM INTEREST RATES

Manitoba Hydro's Financial Forecast from Appendix 1 (Updated) shows an increase in finance expense for 2018/19 and 2019/20 compared to MH-93. Notably MH-93 included a forecast debt management strategy to reduce the Weighed Average Term to Maturity (WATM) down to 12 years that was not implemented. At the time, Hydro anticipated this strategy to reduce finance expense by $500 million over a 10-year period.[32] This approach was not implemented as there was a significant flattening of the yield curve that meant that shorter termed debt was no longer a material savings over longer termed debt.

The flattening of the yield curve, as reviewed below, was a factor of two different price movements – longer termed debt was available at lower rates than expected, and shorter termed debt had higher rates than expected. This was already known by the time of Hydro's opening statement in the 2017/18 and 2018/19 GRA, as indicated in the following excerpt from MH-68 from the previous GRA:

Figure 3: Manitoba Hydro All-in Borrowing Rates from 2017/18 GRA hearing - to November 28, 2017 (slide 64 of MH-68)



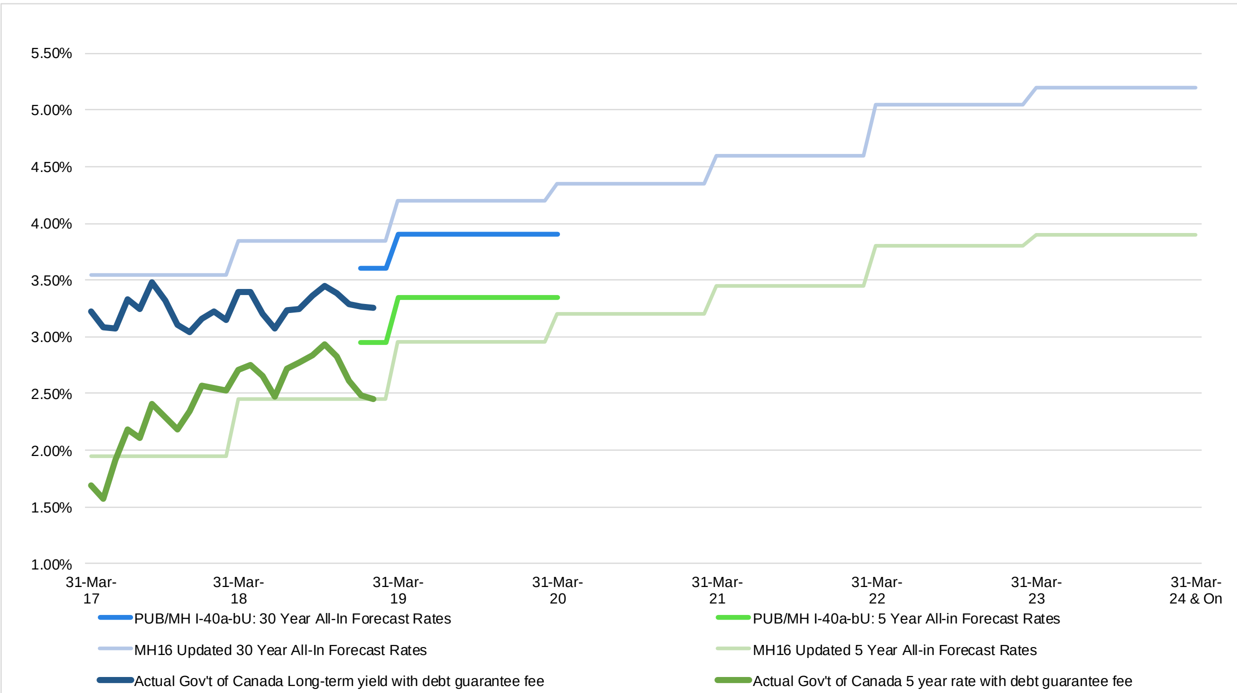
As a result of this pattern, in the short-term (up to 5 years), there was no longer an ability to benefit from low short-term rates. Consequently, Hydro has now indicated that 2018/19 Finance expense was higher than forecast in IFF16 due to this flattened yield curve between long-term and shorter-term maturities.[33] This factor is already included in Hydro's 2019/20 forecasts.

Over the longer-term, however, the above pattern of yield curve flattening should be a significant benefit as compared to MH-93.

[32] MH-68 from 2017/18 GRA, slide 61
[33] Manitoba Hydro 2019/20 Electric Rate Application, November 30, 2018, page 14

At this time, both actual and forecast long-term rates are down considerably compared to MH-93 interest rates. This is shown in the Figure below which shows actual monthly rates for Manitoba Hydro long-term and 5-year bond yields from March 31, 2017 to February 28, 2019. The figure compares to forecast amounts included in MH-93 long-term financial forecast to Manitoba Hydro's 2018/19 and 2019/20 forecasts underpinning Appendix 1 (Updated).

Figure 4: Manitoba Hydro All-in Borrowing Rates Actual Monthly Rates to February 28, 2019 & Forecast Fixed Debt Rate, Comparison to MH16 Long-Term Forecast[34]



The key factor for considering long-term forecasts is the lines in blue (30 year rates). Compared to the MH16 forecast underlying Exhibit MH-93, actual long-term all-in forecast rates were an average of 0.5% lower for 2018/19. For 2019 year to date (i.e. January and February 2019), all-in long-term rates are approximately 0.3% lower than Hydro's latest forecast (3.27% compared to Hydro's forecast of 3.60% for 30 year) and over 0.5% lower than Hydro's forecast underpinning Exhibit MH-93. Starting April 1, 2019, Manitoba Hydro's 30 year all-in forecast rate jumps up by over 0.6% from actuals as of February 28, 2019 (3.90% compared to 3.26% with Mb spread). Consider that monthly long-term rates have remained within

[34] MH16 Updated 30 Year & 5 Year All-In Forecast Rates as of MH-68 in the 2017/18 and 2018/19 GRA, slide 64; Current 30 Year & 5 Year All-In Forecast Rates as of PUB/MH I-40(a-b) Updated; Actual monthly rates as per PUB/MH I-40 and extended for January and February 2019 from Bank of Canada Benchmark bond yields long-term (V122544) and 5 year (V122540) with added Province of Manitoba spreads as provided for those months in PUB/MH I-40(a-b) Updated.

a range of 0.44% over the past two years.[35] This is highly meaningful to the long-term forecasts underlying MH-93 as Hydro finances $1.502 billion in 2018/19 and $1.357 billion in 2019/20 (depending on the approved rate increase, this could be $0.050 billion higher) for Major New Generation and Transmission expenditures.[36]

At the same time, Hydro's vulnerability to changing interest rates is vastly decreasing. Hydro has locked in over $11 billion in debt issuances from 2015/16 to 2018/19 with historic lows for Weighted Average Interest Rate (WAIR) of 3.48% for new borrowings of $2.163 billion in 2016/17 (including provincial guarantee fee). For 2017/18 Hydro locked in $3.381 billion of new borrowings at a WAIR of 3.67%.[37] Hydro's peak borrowing year to finance MNG&T is 2018/19, now largely locked in at below-forecast long-term rates.

Note only has Hydro locked in long-term debt at rates below that assumed in MH-93, Hydro has also reduced a significant component of the long-term interest rate risk underlying that forecast as more and more debt is locked in.

In short, the evidence regarding debt costs not only helps indicate no rate increases are needed in 2019/20 to achieve MH-93 levels of earnings, it also is highly suggestive that long-term forecasts in MH-93 (beyond the five-year horizon) are likely very pessimistic compared to what is now known of Hydro's borrowing costs for those years.

3.2 DEMAND SIDE MANAGEMENT (DSM)

An item of ongoing concern with respect to Hydro's short-term and long-term forecasts is the implicit assumption that large-scale DSM will remain a major cost item (which must be paid for out of rates), and will lead to material reductions in electrical usage, replacing relatively higher revenue domestic sales with lower revenue export sales (which will also lead to a need for higher domestic rates).

This issue has a number of important aspects, in light of the fact that all forecasts since the previous GRA (including Exhibit MH-93 and the current 2019/20 forecasts) have been based on DSM plans prepared in earlier periods and not fully updated, pending clarity on the plans of Efficiency Manitoba. Hydro indicates direction was received from the Province to maintain a continuation of current DSM programs while responsibility transitions to Efficiency Manitoba. Manitoba Hydro's 2018/19 DSM plan was approved by the Minister in August of 2018, subsequent to the issuance of Order 59/18 on May 1, 2018.[38] Hydro refused to

[35] When incorporating Province of Mb. Spreads into Government of Canada 30-year bond yields, rates bottomed out at 3.04% and topped out at 3.48% over the period April 1, 2017 to February 28, 2019.
[36] PUB/MH I-8c Updated
[37] PUB/MH I-38c Updated
[38] MIPUG/MH I-1

provide any information on what information Hydro shared with "the Province" (under an assertion that this would "disclose cabinet confidences nor does it disclose advice, opinions, recommendations, analyses or policy options developed by or for a minister"[39]). The continuation of DSM under a Status Quo framework,[40] following the issuance of Order 59/18, is particularly problematic given the PUB specifically addressed the DSM plans that Hydro continues to use, and concluded that they were prepared:

> …using a now-outdated marginal value of electricity. In light of the new lower levelized marginal value of electricity introduced in this hearing, and as acknowledged by the Utility, some of Manitoba Hydro's demand side management programming will no longer be cost-effective. Consumer rates should not, at this time, recover the costs of demand side management programs that are no longer economic, unless justified by a lower-income target market. [41]

For the ERA update dated February 14, 2019, Hydro indicates DSM spending and savings were updated to reflect: "preliminary projections for DSM expenditures and activities under discussion with the Province for 2019/20 as contemplated by The Energy Savings Act."[42] This updated DSM information has been included in the ERA projections, notwithstanding that Hydro presumably continues to view such "discussions with the Province" as confidential and unavailable to intervenors to test in this proceeding. Hydro indicates that the latest DSM spending and savings projections remain largely status quo with the original problematic November 30, 2018 ERA filing, with the exception that the amount of energy savings is reduced "largely due to the delayed implementation of the Conservation Rates initiative, the Fuel Choice Initiative and revised assumptions related to Load Displacement projects."[43] It appears no material changes have been assumed to any of the other myriad DSM programs, despite the fact that the PUB has indicated they should not be included in customer rates.

To summarize, in terms of effect on the current rate review, three aspects are of particular importance:

1) **DSM spending:** The previous GRA reviewed information from the Boston Consulting Group work that indicated that Hydro's financial ratios could be materially strengthened (and consequently the level of rate increases mitigated) through reducing the scale of DSM assumed.[44] Such actions would

[39] MIPUG/MH I-1
[40] "The future program based DSM savings incorporated in the 2019/20 Interim Budget are based on the 15-Year DSM Plan Supplement Report filed in Appendix 7.2 of the 2017/18 & 2018/19 GRA adjusted for actual DSM savings achieved in 2017/18 and the carry-forward effects of the changes made to the 2018/19 one-year DSM plan prepared in consultation with the Manitoba government (filed in response to PUB MFR 61 during the 2017/18 & 2018/19 GRA)." Per Hydro November 30, 2018 filing, page 31
[41] PUB Order 59/18, page 23
[42] Hydro February 14, 2019 Supplementary filing, page 10.
[43] Hydro February 14, 2019 Supplementary filing, page 11.
[44] See Exhibit MIPUG-13 from the 2017/18 GRA, Summary provided in section 6.3.2

be consistent with the purpose of Efficiency Manitoba, which is specific to include "mitigating the impact of rate increases."[45] However, such mitigative actions were never included in the forecasts prepared as part of Exhibit MH-93, and similarly have not been included in the current ERA forecasts. It is unclear that this information has been made available to the Province or Efficiency Manitoba as part of Hydro briefing them on the implications of Order 59/18, given Hydro maintains such briefings are confidential. As a result, it is unclear that the Province is intentionally seeking to include in customer rates the costs of uneconomic DSM. Regardless, the PUB's conclusion that customer rates should not include uneconomic DSM (unless justified by a lower income program) remains valid and should be a consideration in the current ERA. Absent a properly prepared DSM program reflecting up-to-date and fully tested marginal costs, it should be assumed that the DSM programs underlying both the 2019/20 forecast and the Exhibit MH-93 forecasts include higher spending levels than should be accepted into customer rates.

2) **Marginal Value:** The previous GRA reviewed evidence that after preparing the then-existing DSM plans, and after filing the GRA documents itself, Hydro then reduced the marginal value by 28%.[46] Given the short-term focus on Hydro's filing, no update is available regarding the long-term marginal values. The previous 28% reduction is a factor in concluding that the MH-93 trajectory can be achieved with lower domestic rates so long as DSM spending is appropriately matched to marginal values.

3) **Scope of future programming:** the DSM plans underlying Exhibit MH-93 included long-term spending on a number of plans that are not presently included in the 2019/20 forecast, particularly Residential Conservation Rates, Commercial Conservation Rates and Fuel Choice programming.[47] This was justified as the province desired no new programs to be run, and Efficiency Manitoba had not yet developed their suite of programs to determine what might be included. The introduction of lower marginal values would likely limit the rationale and, in the event it is still justified, the impact of any conservation rates program pursued. On the matter of Fuel Choice, this program was developed to encourage reduced electricity consumption in favour of more economic natural gas conversion. The status of such program would appear dubious under the transition to Efficiency Manitoba which also has a mandate to reduce natural gas consumption, and a greater focus on reducing carbon emissions than Manitoba Hydro's electrical DSM program. For this reason, there

[45] Efficiency Manitoba website, About Efficiency Manitoba section. Accessed March 28, 2019. Available online: https://www.gov.mb.ca/cs/em.html
[46] PUB Order 59/18, page 116.
[47] MIPUG/MH I-2a

is a basis for further concern that MH-93 overstates the need for domestic rates to fund DSM programs (and offset electrical revenue reductions) that are not likely to occur.

4) **Concerns over programs selected:** While the scope of the present review does not include the particular DSM programs to be offered, it is striking that Manitoba Hydro has migrated significant DSM spending and savings targets away from long-term effective programs such as Industrial Performance Optimization (2019/20 reduced by 60%, from 23.2 GW.h to 9.2 GW.h) while introducing new programs of unproven and contentious value, such as Residential Photovoltaic (9.2 GW.h) and Commercial Photovoltaic (9.3 GW.h) customer generation[48] as well as expanding residential LED lighting programs by 130% (from 4.7 to 10.8 GW.h). Note that Board specifically expressed concerns in Order 59/18 (page 207) about the solar photovoltaic programming and the degree to which rates and cost recovery in Manitoba may not yet be properly structured for such initiatives, as follows:

> In addition, the Board heard evidence in this proceeding about the potential for increased use of disruptive technology for non-utility generation, such as customer solar photovoltaic installations. This could potentially require the review of demand charges in the near future in order to ensure that class revenues are fully recovered and that the value of grid reliability is properly assessed when used by customers as a back-up power resource.

It is also of note that the scale of impacts from varying DSM activities is material. The February 2019 Hydro update for this reduced programming, including an $18 million increase in net revenues ($30 million in additional domestic sales revenue offset by approximate $12 million in lost export revenue) and a reduction of planned program expenditures for 2019/20 of $33 million associated with this change in DSM activity.[49]

3.3 IMPACTS OF BIPOLE III COSTS AND KEEYASK FORECASTS

Bipole III (with Riel Station) finished construction and was partially in-service in the 2017/18 year, fully in-service in 2018/19. In Hydro's last GRA (CEF16 and MH-93 long-term revenue requirement) the control budget was $5.04 billion, which was unchanged in Hydro's initial 2019/20 ERA filing. The final capital cost was reduced to $4.77 billion and incorporated in Hydro's Updated ERA filing for final project in-service costs, resulting in a reduction to revenue requirement in 2019/20 of $30 million compared to Hydro's original 2019/20 ERA filing, largely to finance and depreciation expense.[50]

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[48] PUB/MH-I-50a-d (Updated)
[49] MIPUG/MH I—2b
[50] PUB/MH I-57

The downward revision to Bipole III capital costs is a material an enduring benefit to the costs that ratepayers will face.

Longer-term impacts of Keeyask's 2021/22 in-service date on revenue requirement have not changed significantly from MH-93, as shown in the Table below. This does not include forecast revenue increases resulting from the increased dependable energy and capacity of the generating station, nor the increased export/import access that will also be in place at this time following completion of the GNTL/MMTP interconnection. Of note, the 2019/20 outlook already includes $35 million for Keeyask recovered from ratepayers for capital tax.

Table 1: Keeyask Revenue Requirement Forecast Comparison, 2019/20 Outlook to MH-93 $ Millions[51]

2019/20 Update	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Finance Expense						119	329				
OM&A Costs						9	16				
Depreciation						21	99				
Capital Tax			29	35	39	42	43				
Water Rentals						5	14				
Total			**29**	**35**	**39**	**196**	**501**				
2017/18 GRA	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Finance Expense						114	310	387	380	377	370
OM&A Costs						9	16	16	16	16	17
Depreciation						23	107	121	121	121	121
Capital Tax	16	22	28	34	38	42	43	42	42	41	41
Water Rentals						4	14	15	18	18	18
Total	**16**	**22**	**28**	**34**	**38**	**192**	**490**	**581**	**577**	**573**	**567**
Difference			**1**	**1**	**1**	**4**	**11**				

Of Keeyask's $8.7 billion capital budget, as of December 31, 2018, $5.53 billion has been spent, or 64%.[52] Of the remaining project costs, a material portion is interest during construction, which is less likely to change than direct project expenditures. Additionally, since the last GRA, the first unit is now indicated to be 10 months ahead of schedule and this has helped lower forecast project costs.[53] As Keeyask construction is in its final 2-3 years, over half of the funds have been secured at low interest rates and it remains on schedule.

3.4 CAPACITY VALUES AND DEPENDABILITY PREMIUMS ON EXPORT SALES

In terms of long-term forecasts, one factor that should be considered is the most likely scenario with respect to export revenues. A limitation of exhibit MH-93 has been that it included no value attributed to Manitoba Hydro's ability to secure export revenues associated with capacity sales, nor with any dependability

[51] PUB-MFR-20 from 2017/18 GRA and PUB/MH I-9U for 2019/20 Update
[52] PUB/MH I-54U, Keeyask Project Update Q3 December 31, 2018, page 9 of 27
[53] PUB/MH I-54U, Keeyask Project Update Q3 December 31, 2018, page 9 of 27

premium associated with Hydro's dependably exports. For this reason, MH-93 was always recognized as a pessimistic scenario, as the Board did not agree with Hydro's forecasting method for these matters. As noted in Order 59/18, page 125:

> The financial effect of Manitoba Hydro's revisions to the export price forecast is to value all surplus energy at opportunity prices rather than ascribe a higher value for its dependable surplus product.
>
> …
>
> Manitoba Hydro assumes no new firm long term contracts will be negotiated for the substantial surplus dependable energy and capacity in the 20-year forecast. Manitoba Hydro further assumes existing long-term firm contracts will expire without negotiating extensions.

The Board's Independent Experts concluded this was not an appropriate forecasting approach (Order 59/18, page 127):

> Daymark found that not including the premium or capacity value may be reasonable in the short term but not in the long term, as there is evidence that the Midcontinent Independent System Operator market will be short capacity by 2022 and United States Federal and State policies may still favour Manitoba Hydro's carbon-free, firm electricity exports.
>
> In summary, Daymark found that Manitoba Hydro's export revenue forecast is conservative or low relative to Manitoba Hydro's stated goal of having a P50 forecast of export revenues.

The Board accepted this conclusion, and also noted at page 129 of 59/18:

> Additionally, the Board finds that Manitoba Hydro's export revenue forecast is low as it does not reflect the estimated 2% to 5% increase in export prices (and 2% to 5% reduction in import prices, which will increase the net export revenues) that will be achieved once the Manitoba-Minnesota Transmission Project and the Great Northern Transmission Line are in service.

For each of these reasons, the export revenue forecast prepared as part of MH-93 should be viewed as conservative. Manitoba Hydro responded to these directives at page 23 of the November 30, 2018 application, noting that no dependability premium nor unsold capacity revenue have been included in 2019/20 as Hydro has "relatively small levels of unsold dependable energy and capacity in 2019/20".[54]

[54] Hydro November 30, 2018 Application, page 23.

Consistent with Hydro's approach, Hydro has made no comment about the Board's direction as it may affect years beyond 2019/20.

There is no information publicly available as to the degree to which MH-93 understates long-term export revenues due to this assumption. Hydro did produce Exhibit 140-1 (part b) in the previous GRA which provided the impact, but all relevant values were redacted. Nonetheless, this remains one additional reason why MH-93 as the benchmark may be conservative regarding future forecasts and an updated forecast should indicate improved performance regarding this aspect of export revenues.

4.0 RATEPAYER CONSIDERATIONS

The proper consideration for imposing rate increases, and the relative level of rates charged to each class of customers, is the underlying costs to provide service.

While this is the predominant factor, the Board may also consider customer and other public interest factors in determining whether a rate increase is justified. This may include considerations such as promoting rate stability; avoiding rate shock; and maintaining intergenerational equity. In consideration of ratepayer perspectives on the requested 3.50% rate increase, the following are noted:

1. Manitoba Hydro's 2019/20 approved budget forecast does not demonstrate financial need for any level of rate increase effective June 1, 2019.
2. By not providing a long-term financial forecast, Manitoba Hydro has not met the PUB's requirement to file financial and economic information sufficient to satisfy its onus to demonstrate that the 3.50% rate increase sought for the test year is just and reasonable.
3. At the same time, industrial customers through MIPUG have stated a preference for moderate, predictable rate increases over time.

Based on these perspectives, the Board will need to weigh whether a 0% rate increase is the appropriate response, or whether customer interests may be served by approving a modest inflationary rate increase. Such a rate increase of approximately 1.5% in 2019 could be viewed as being consistent with the principles of rate stability and predictability, given there is a known need to transition to a new higher rate level at some point in the future, to address the costs of Keeyask and potentially MMTP coming in-service.

With respect to the treatment of the interim rate increase, the Board has stated its view that there is a compelling policy interest to phase in rate increases over a number of years in advance of the in-service dates of new major capital projects. To that end, the Board has previously directed that a portion of approved rate increases be designated to flow into the Bipole III deferral account to assist in the payment of in-service costs.[55] While pre-funding of future capital projects can be problematic from a regulatory perspective, the Board created this mechanism at the time to address future rate pressures, with the end result helping to smooth the transition of Bipole III now that it is in-service.

In this instance, should be Board view that some inflationary increase is directionally appropriate, it would be most consistent with the evidence in the proceeding that such rate increase be directed into a deferral account for the in-service of Keeyask, as well as MMTP to the extent required. Such an increase could help promote rate stability in the medium-term (next 2-3 years), while also helping ensure the 2019/20 additional rate revenue provides some degree of future rate stability when Keeyask comes in-service.

The major difference between Keeyask and Bipole III is that Keeyask will have some offsetting revenues when in-service. Since an assessment of the net impacts to customers was not undertaken as part of this review, and the current proceeding is not interim but final in nature, the PUB should consider a maximum level of rate increase no higher than inflation, currently estimated by the Bank of Canada at 1.5%.

Even such an inflationary increase at no higher than 1.5% should not be taken lightly. The impact of such increases is material to industrial customers. For industrial customers rate competitiveness and predictability are primary concerns for controlling costs and managing operations. Expedited processes, without the benefit of a fulsome review of Hydro's long-term financial position undermines these customer needs. The Public Utilities Board has noted in previous proceedings that the expedited process typically undertaken for interim rate proceedings, but which fully applies to the current proceeding, "…are not to be used for purposes of convenience or as substitutes for the proper planning of GRAs."[56] Additionally, in the current economic context, competitiveness is further undermined as other Canadian jurisdictions are increasing rates to a much lower degree while at the same time offering programming for industrial customers to manage electricity bills. For example:

- Hydro Quebec's rate increase for April 1, 2019, for the fourth year in a row, is seeking industrial rate increases at 0.3% or less for its Rate L, while at the same time initiating significant economic development incentives (including up to 20% off of power bills for new or expanding companies).[57]

- Comparatively, BC Hydro is proposing a rate increase of 1.76% for April 1, 2019 and 0.72% for April 1, 2020.[58] Industrial rate options in BC include the recurring Freshet rate pilot project (a

[55] PUB Order 73/15, page 23
[56] PUB Order 59/18, page 19.
[57] Annual Report of Hydro-Quebec for fiscal year end December 31, 2018, page 18. Available online: http://www.hydroquebec.com/investor-relations/pdf/18K-2018.pdf
[58] BC Hydro Fiscal 2020 and Fiscal 2021 Revenue Requirement Application, filed February 25, 2019. Available online: https://www.bcuc.com/Documents/Proceedings/2019/DOC_53488_B-1-BCH-F20-F21-RR-Application.pdf

surplus energy purchasing program for industrial customers during the spring runoff period May – July available at market prices) and is currently in discussions to expand the program to full year.[59] BC Hydro also offers an optional Time Of Use rate for industrial customers.[60]

[59] See Rate Schedule 1892 of BC Hydro's Transmission Service rate schedules, page 5-25. Available online: https://app.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/tariff-filings/electric-tariff/bchydro-electric-tariff.pdf
[60] Ibid, Rate Schedule 1825, page 5-6