

**Public
Utilities
Board**

**Régie
des
services
publics**

**MANITOBA HYDRO
FISCAL 2026-2028 GENERAL RATE APPLICATION
PUB/COALITION INFORMATION REQUESTS**

October 15, 2025

PUB/Coalition I-1

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|--------------------------|---|----------------|-----|
| Part and Chapter: | CC-20 (Dr. Das Report) | Page #: | 7-9 |
| Topic: | Measurement Approaches for Energy Poverty | | |
| Subtopic | | | |

Preamble (if any):

Beginning at p. 7, Dr. Das outlines the various approaches that have evolved over the past several decades to measure energy poverty. These include the 10% rule, >2M approach, Low Income High Cost (“LIHC”) indicator, and Low Income Energy Efficiency (“LILEE”) indicator.

Question:

- a) Does Dr. Das have Manitoba statistics using each of these metric? If so, please file a table or other data that assesses energy poverty in Manitoba against each of these metrics.
- b) What is Dr. Das’ preferred metric and why?

Rationale for Question:

To understand the application and effect of the different measurement approaches in Manitoba.

Response:

- a) The following table provides an overview of metrics assessed in Manitoba.¹

| Indicator/ Source | Year (Data Source) | Income Basis | Housing Costs | Manitoba Estimate (%) | Canada Estimate (%) | Notes |
|---|--|-------------------------|--------------------------|--------------------------------------|------------------------------------|----------------------------------|
| 10% rule – Das et al. (2022) ² | 2016 (Survey of Household Spending) ³ | Before-tax income | Both before and after | ~4 (before housing); | ~7–9 | Provincial values from Fig. 2 in |

¹ Note the LIHC and LILEE have yet to be assessed in Canada.

² Das, Runa R, Mari Martiskainen, and Grace Li. 2022. “Quantifying the Prevalence of Energy Poverty Across Canada: Estimating Domestic Energy Burden Using an Expenditures Approach.” *Canadian Geographer* 66 (3): 416–33. <https://doi.org/10.1111/cag.12750>.

³ Note the 2016 and 2017 Survey of Household Spending sampling frame excludes:

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|--|-------------------------------------|------------------|--------------------------------|---|--------|---|
| | | | housing costs | ~6 (after housing) | | Das et al. 2022 |
| 10% rule – Riva et al. (2021) ⁴ | 2017 (Survey of Household Spending) | After-tax income | Before and after housing costs | ~5 (before housing); ~7.7 (after housing) | ~6-10 | Provincial values from Figure 2 in Riva et al. 2021 |
| 10% rule – Statistics Canada (2024) ⁵ | 2022 (Canadian Income Survey) | After-tax income | Before housing costs | 5.5 | 5.6 | Most current official estimate; Manitoba among the highest outside the Atlantic region and territories. |
| > 2M (Twice-Median) – Riva et al. (2021) | 2017 (Survey of Household Spending) | After-tax income | Before and after housing costs | ~14 (before housing); ~16 (after housing) | ~18-19 | National estimate only; provincial breakdown unavailable. |

b) I do not have a single preferred metric. Each approach to measuring energy poverty offers distinct advantages and limitations, depending on available data and policy objectives.

- 10 percent rule

residents of institutions, members of the Canadian Forces living in military camps, and Indigenous peoples living on reserves.

⁴ Riva, Mylene, Sophie Kingunza Makasi, Philippe Dufresne, Kimberley O'Sullivan, and Megan Toth. 2021. "Energy Poverty in Canada: Prevalence, Social and Spatial Distribution, and Implications for Research and Policy." *Energy Research & Social Science* 81 (102237), <https://doi.org/10.1016/j.erss.2021.102237>.

⁵ Statistics Canada (2024). *Energy poverty in Canada, 2022*. <https://www150.statcan.gc.ca/n1/pub/46-28-0001/2024001/article/00001-eng.htm>

- **Advantages:** Simple, transparent, and easy to calculate. It provides a clear affordability threshold and has been widely applied in Canada and internationally, making it good for comparative reasons. It appears to pick up more people in lower-income than the 2M threshold.
- **Limitations:** The 10 percent cutoff is an arbitrary threshold that does not account for regional cost differences, climate, or variations in disposable income, among other challenges, and is therefore blunt. It can overestimate energy poverty when energy prices are high and underestimate it when households self-ration or live in inefficient dwellings but keep bills low. It does not measure the depth or severity of the experience of facing energy poverty.
- **Twice-median (>2M) indicator**
 - **Advantages:** Adjusts the threshold dynamically to the national energy-expenditure distribution, making it less sensitive to price fluctuations and more comparable across time and place. It captures relative deprivation rather than a fixed standard. It is based on the original derivation of the 10% indicator.
 - **Limitations:** It is still somewhat arbitrary. A relative threshold can remain stable even when everyone's costs become unaffordable. The 2M tends to classify more households as experiencing energy poverty in higher income quintiles compared to the use of the 10%.
- **Low-Income Low Energy Efficiency (LILEE) indicator**

Conceptually, this is the most comprehensive measure, as it integrates both income and building-performance factors. A household is considered to face energy poverty if it has a low income and occupies an inefficient dwelling that would require high energy costs to maintain adequate comfort.

However, implementing LILEE in Manitoba is not yet feasible, because it requires dwelling-level energy-efficiency ratings or building performance data, which are not currently available for most residential buildings in the province.

In my opinion, the Low Income Low Energy Efficiency (LILEE) framework offers the most conceptually robust metric, because it explicitly incorporates both household income and dwelling energy performance (i.e. the structural, technical side of energy cost risk). Under LILEE, households are considered to face energy poverty if they have low incomes *and* live in properties of poor efficiency—those where cost burdens are amplified by inefficient stock.

The barrier in Manitoba (and many other jurisdictions) is data availability: most dwellings lack standardized energy-efficiency ratings or sufficiently granular building performance data.

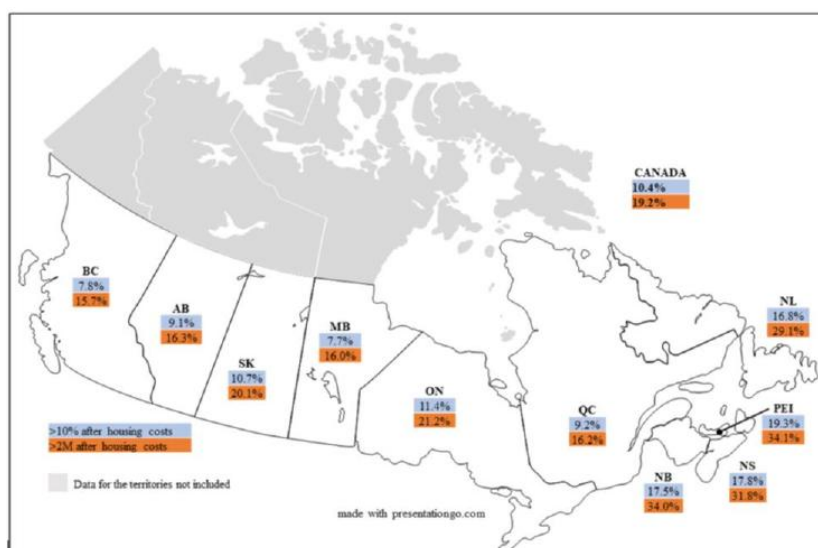
Thus, my considered approach would be: In the near term, use 10% and > 2M methods in tandem (not as competitors, but as complementary lenses). Over time, as building performance data improve, transition toward LILEE

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|--------------------------|---|----------------|----|
| Part and Chapter: | CC-20 (Dr. Das Report) | Page #: | 13 |
| Topic: | Prevalence and Regional Variation in Energy Poverty | | |
| Subtopic | | | |

Preamble (if any):

At pages 12-13, Dr. Das reviews the provincial variability in energy poverty by using the 10% rule and >2M approach. Figure 1 demonstrates the provincial variation:



Question:

- Please confirm that Manitoba is the province with the lowest proportion of households facing energy poverty according to the 10% rule, and with the second lowest proportion according to the >2M approach. If not confirmed, please explain where Manitoba ranks in comparison to other provinces.
- Does Manitoba’s standing mean that energy poverty programs are less important in Manitoba than in other jurisdictions? If not, please explain and elaborate.
- Is there a North-South split in Manitoba with respect to the prevalence of energy poverty, or are there any other significant regional differences?

Rationale for Question:

To better understand the effect of the overall prevalence of energy poverty in Manitoba, as well as the regional prevalence within the province.

Response:

- a) It cannot be confirmed in full.

Under the 10 percent rule, Manitoba consistently records among the lowest rates of energy poverty in Canada, but not necessarily the single lowest, depending on data year and source.

- In Riva et al. (2021) (2017 SHS, after-tax income): Manitoba's rate was ~ 5% (before housing costs) and ~ 7.5% (after) - second lowest with respect to before housing costs estimates, slightly above Quebec (~ 5 %) and close to British Columbia and Alberta.
- In Das et al. (2022) (2016 SHS, before-tax income): Manitoba's rate was ~ 4% (before housing costs) and ~ 6% (after housing costs); before housing costs estimates are similar to those found in British Columbia (4%), Quebec (4%), and higher than in Alberta (3%). Estimates taking into account after housing costs are similar to those in BC, and higher than that of Alberta.
- In Statistics Canada (2024) (2021 Census, after-tax income): Manitoba was 5.5%, compared with the national average of 5.6 % - and higher than estimates for Quebec (4.2%), Ontario (4.8%), and British Columbia (4.8%).

Under the > 2M (twice-median) indicator, Manitoba also ranks near the low end but not the absolute second-lowest in every dataset.

- In Riva et al. (2021), Manitoba's > 2M rate was roughly 14% (before) and 16% (after housing costs) - slightly higher than Quebec but lower than the Prairie and Atlantic provinces overall.

In summary, Manitoba appears to be generally among the three provinces with the lowest measured incidence of energy poverty across both metrics, though there are year-to-year differences.

- b) No. A provincial average on the lower end does not mean energy poverty programs are less important in Manitoba.

Several factors qualify this interpretation:

1. **Distributional inequality:** Even if the overall share of households in energy poverty is smaller, affected households tend to face deeper affordability challenges, particularly in low-income, Indigenous, and rural communities.
2. **Climatic and housing factors:** Manitoba experiences longer heating seasons and higher per-capita energy consumption than most provinces. The combination of cold climate, age and condition of housing stock, creates vulnerability for certain groups even when the provincial average appears low.

3. **Equity and just transition considerations:** Energy-poverty programs play a critical role in ensuring that energy-efficiency and electrification initiatives reach low-income and northern households equitably.
4. **Preventive function:** Jurisdictions with lower measured incidence can still experience rapid affordability stress if prices or supports shift. Maintaining proactive programs mitigates that risk.

Thus, Manitoba's relatively lower average does not diminish the importance of targeted energy-affordability and efficiency programs.

- c) While detailed intra-provincial statistics are limited, the available evidence suggests regional variation does exist.
- **North–South gradient:** A North–South split is likely due to climatic, infrastructural, and income differences. Households in Northern and remote communities (including many Indigenous communities) can face higher energy costs and greater reliance on diesel or electric baseboard heating, leading to elevated energy burdens.
 - **Urban–rural differences:** Rural households tend to exhibit higher energy burdens, consistent with national findings (Das 2022; Riva 2021). Rural homes are often older, larger, and less efficient, and households have lower average incomes.
 - **Southern urban centres:** In southern urban centres such as Winnipeg, the housing stock includes a larger proportion of multifamily and rental units compared to rural and northern areas. Research across Canada indicates that multifamily and rental households can face higher relative energy burdens because of lower incomes, shared metering, and limited ability to improve building efficiency.

Comprehensive mapping of intra-provincial variation would require integrating energy-use, housing-efficiency, and income data - an area I identify as a key research need. Although, to my knowledge, this information has not been published, conducting this research should be doable with Statistics Canada datasets.

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|--------------------------|-------------------------------|----------------|-------------------------|
| Part and Chapter: | CC-20 (Dr. Das Report) | Page #: | 4, 24-25, 36, 39-40, 42 |
| Topic: | Bill Affordability | | |
| Subtopic: | Efficiency Manitoba Offerings | | |

Preamble (if any):

Dr. Das submits that “Manitoba Hydro’s existing affordability programs provide important but limited relief” and that “compared to other provinces, Manitoba lacks ongoing bill credits or targeted low-income retrofit programs” (CAC-20 p.4). Further, p. 39 of the report states that Manitoba Hydro’s current programs “do not fundamentally reduce energy poverty” and that “without expanded and better-targeted affordability initiatives – particularly those designed in partnership with Indigenous communities and low-income households – these programs will remain palliative rather than transformative.”

The Efficiency Manitoba Act (Act) establishes Efficiency Manitoba as the Manitoba crown corporation responsible for delivery energy efficiency initiatives in Manitoba. Prior to its establishment, Manitoba Hydro (and its gas subsidiary Centra Gas) offered various demand-side management programs (including programs targeting low-income customers) to reduce or shift electricity and natural gas consumption in Manitoba. Per the legislative requirements, the approval of Efficiency Manitoba’s initial three-year efficiency plan would transfer responsibility for demand-side management programming from Manitoba Hydro to Efficiency Manitoba, although the cost of these offerings would continue to be supported by Manitoba Hydro and Centra Gas ratepayers. In 2019-2020, the Board reviewed Efficiency Manitoba’s 2020/21 to 2022/23 Efficiency Plan and, pursuant to the requirements of the Act (and the related regulation), submitted its report and recommendations to the Government of Manitoba. Details of the Board’s review process for this proceeding can be found at <https://www.pubmanitoba.ca/v1/proceedings-decisions/appl-current/em-2020-23-plan.html>. The Government of Manitoba has since extended Efficiency Manitoba’s initial three-year plan beyond 2022/23.

Consistent with its 2019-2020 submissions, Efficiency Manitoba currently offers various program offerings, including its residential income-qualified and indigenous programs, which generally seek to address equity and affordability issues related to the adoption of building energy efficiency retrofit solutions.

Table 2 of Dr. Das’s report (pages 23-29) presents a jurisdictional scan of programs that can address energy poverty in Canada. Notably, Efficiency Manitoba’s existing program offerings in Manitoba are not presented.

Question:

- a) Please detail Efficiency Manitoba’s demand-side management program offerings that are currently available to residential low-income and indigenous energy customers in Manitoba.

- b) Please explain whether Efficiency Manitoba’s existing program offerings meet some of the Manitoba Hydro affordability program deficiencies and structural inequities identified in the report. If so, please also explain whether this information leads to alternate or modified report recommendations.

Rationale for Question:

To assess bill affordability issues in the full context of existing program offerings in Manitoba.

Response:

- a) Efficiency Manitoba currently delivers a range of demand-side management (DSM) and energy-efficiency programs that support equity and affordability objectives for households with lower incomes and for Indigenous communities. I have done a scan of Efficiency Manitoba’s website. Below are some notable initiatives. It should be noted that I have not included all programs, and there are others that could be beneficial such as, for example, the Community Heat Pump Program, EnerGuide Home Evaluation Rebate, and other community focused programs.

| Program | Description/Eligibility | Target Group/Notes |
|--|--|--|
| Instant Rebates | Instant rebates on select energy-efficient products at participating retailers. | Appears open to all households. |
| Energy Efficiency Assistance Program (EEAP) | Provides free or subsidized upgrades such as insulation, air sealing, lighting, and heating/cooling improvements. Includes home energy assessments, installation, and post-inspection. Part of the Affordable Home Energy Program. | Income-qualified households (owners and renters), including on-reserve and off-reserve First Nations living off-reserve or own your home on reserve. |
| Métis Energy Efficiency Offers | Free and subsidized energy efficiency upgrades. This program is designed to help Red River Métis homeowners | Red River Métis citizens. Homeowners or tenants in a single or semi-detached home. |

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|---|---|--|
| | <p>and renters save on their energy bills by providing affordable energy efficiency upgrades for their home. If you're renting a home, we can work with your landlord to have energy efficiency upgrades completed in the house you're living in. Part of the Affordable Home Energy Program.</p> | |
| <p>First Nation Energy Efficiency Program</p> | <p>We partner with your community on energy efficiency goals to reduce energy consumption and address bill affordability. Upgrades are free and our First Nation Energy Advisor works with you to create a plan and identify a labour solution that works for the community.</p> <ul style="list-style-type: none"> • FREE insulation upgrades • FREE LEDs • FREE smart thermostats • Enhanced rebates on high-performance windows and doors • FREE low-flow showerheads and faucet aerators • FREE insulated pipe wrap • FREE advanced power strips | <p>First Nation individuals living off-reserve or own your home on reserve may be eligible for the same energy efficiency upgrades through the Energy Efficiency Assistance Program.</p> |
| <p>Indigenous Community Energy Efficiency Program</p> | <p>We offer communities the opportunity, support, and resources to hire an energy efficiency advocate to create and</p> | <p>Communities recognized as First Nation in Manitoba.</p> |

| | | |
|--------------------------------|--|--|
| | implement community energy efficiency plans with guidance from our energy experts. | |
| Affordable Home Energy Program | Efficiency Manitoba is supporting the delivery of the Affordable Home Energy Program by providing financial support for the installation of energy-efficient heat pump systems in Manitoba homes. We have multiple offers available to help Manitobans upgrade their home heating system to a ground source heat pump. | Many different customer segments are targeted. |

Source: Efficiency Manitoba website: <https://efficiencymb.ca/>

- b) Efficiency Manitoba’s current programs address several of the affordability and equity gaps identified in my report, though significant limitations remain.

I observed that Manitoba’s affordability programming, delivered through Manitoba Hydro (with partners), provide important but limited relief. These initiatives reach some low-income and Indigenous households, but overall support is modest and primarily focused on short-term bill assistance rather than on structural reductions in energy burden.

Efficiency Manitoba’s present suite of programs represents a step forward. Through its **Energy Efficiency Assistance Program** and **Affordable Home Energy Program**, Efficiency Manitoba targets income-qualified households and offers free or subsidized upgrades such as insulation, heating-system improvements, and heat pumps. Dedicated Indigenous-specific initiatives, delivered in partnership with First Nations and Métis governments, are intended to increase participation and build community capacity. These efforts reflect a shift toward structural, efficiency-based solutions that can reduce long-term energy costs rather than providing only short-term more temporary relief.

The Public Utilities Board’s Report on Efficiency Manitoba’s 2020/21 to 2022/23 Efficiency Plan recognized similar issues of accessibility and equity. During that review, interveners—including the Assembly of Manitoba Chiefs—argued that Efficiency Manitoba’s definition of “accessibility” was equated with program “availability” rather than programming being obtained easily or used. Though I do

not list all of them below, some of the important and relevant recommendations included Efficiency Manitoba to:

- Monitor and track participation in its programs particularly for First Nations and other hard to reach customers so that it can be responsive to adjustments needed to overcome barriers to participation;
- Engage directly with individual First Nations communities in order to effectively evaluate the degree of saturation of the market;
- Address the accessibility of all Residential and small business programs to Indigenous Residential and small business customers as well as the availability of energy efficiency loans to customers with accounts in arrears through clear education, marketing, and outreach processes;
- Conduct additional research and direct engagement on use of a dedicated funding model for each First Nation and on gaps between bill savings for First Nations on-reserve and Income Qualified programs.

Adhering to above recommendations would represent meaningful progress and partially address the deficiencies identified in my report. However durable solutions to energy poverty require a multi-pronged approach: improving energy efficiency is essential, but sustained affordability measures and targeted bill support remain equally critical. The one-time *Neighbours Helping Neighbours* grant, for example, provides temporary relief but is insufficient to mitigate ongoing hardship for households with high energy burdens.

Therefore, while Efficiency Manitoba's current initiatives mitigate some of the structural gaps previously identified, they do not fundamentally alter the report's conclusions.

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| Part and Chapter: | CC-20 (Dr. Das Report) | Page #: | 4, 37-38, 41 |
| Topic: | Bill Affordability | | |
| Subtopic: | Manitoba Hydro Offerings | | |

Preamble (if any):

In response to Directive 5 of Order 73/15, a Bill Affordability Working Group was established in September 2015, consisting of representatives from Manitoba Hydro, various interveners to Manitoba Hydro’s regulatory proceedings, as well as other related stakeholders. As part of its summary report and recommendations, which was filed as Appendix 10.5 in the 2017/18 Manitoba Hydro GRA, the working group found that “service terminations fall disproportionately on First Nations customers” and that “the relationship between arrears and energy poverty is in fact weak. However, among customers who are in arrears, there is a stronger link between low income and higher energy burden levels compared to the general sample.”

At the 2023/24 & 2024/25 Manitoba Hydro GRA, Manitoba Hydro submitted that it uses a holistic bill affordability program stacking approach and refers customers who are struggling to pay their bills to various organizations such as Efficiency Manitoba and local community support organizations (reference 2023/24 GRA exhibit MH-33 p.29, exhibit MH-57 pp. 201-203, and GRA transcript pages 1192-1196). For example, Manitoba Hydro automatically completes an application for Efficiency Manitoba’s Energy Assistance Program when enrolling a customer in the Neighbours Helping Neighbours program. A dedicated First Nations account team is also used by Manitoba Hydro to support these customers, including dealing with issues such as arrears and payment arrangements.

At p. 41 of the report, Dr. Das advocates for stronger protections against disconnections as “the practice continues to disproportionately affect low-income customers.”

In regards to the Neighbours Helping Neighbours program, p. 37 of the report identifies that funding for the program is based on fixed annual contributions from both Manitoba Hydro and customer donations, and that in some years, the program has been fully subscribed before year-end, leaving some eligible households without support. In response, p. 41 of the report recommends that Manitoba Hydro invest in targeted outreach to increase uptake of crisis supports (including expanding program eligibility) and that linking arrears management to energy efficiency upgrades or educating programs could strength long-term outcomes.

In COALITION/MH I-191h, Manitoba Hydro indicates that the Neighbours Helping Neighbours program has an eligibility criterion that limits participation from individuals receiving social assistance.

Question:

- a) Please further explain the link between arrears (i.e., unpaid bills) and utility customer income levels and provide the applicable sources of information supporting the statement at p. 41 of the report that disconnections in Manitoba “continues to disproportionately affect low-income customers”.
- b) Please explain whether the Neighbours Helping Neighbours program participation-related issues identified in the report may be related to the fact that the program’s existing eligibility criterion limits participation for individuals receiving social assistance.
- c) Please explain whether increasing crisis support and arrears management tools would necessarily require additional funding from Manitoba Hydro, which could in turn, given the lack of a separate low-income ratepayer class, contribute to further upward pressure on the rates paid by these customers.
- d) Please further explain the expanded Manitoba Hydro arrears management tools sought in the report in light of Manitoba Hydro’s existing bill affordability programs and customer service approach, as well as Efficiency Manitoba’s demand-side management offerings, and the available supports from government agencies or community-based organizations.

Rationale for Question:

To better understand the underlying justifications and specific program changes referenced in the report’s recommendations.

Response:

- a) Arrears are not a perfect proxy for energy poverty across Manitoba Hydro’s entire customer base. However evidence from Manitoba and beyond shows that households with lower incomes and higher energy burdens are more likely to face disconnections. In its Bill Affordability Working Group Report (Appendix 10.5, 2017/18 GRA), Manitoba Hydro found that “service terminations fall disproportionately on First Nations customers” and that “the relationship between arrears and energy poverty is in fact weak. However, among customers who are in arrears, there is a stronger link between low income and higher energy-burden levels compared to the general sample.”

My own analysis of the Residential Energy Survey similarly shows that First Nations households in Manitoba face some of the highest rates of energy poverty. Given that Manitoba Hydro’s own evidence shows that service terminations disproportionately affect First Nations customers, it follows that those experiencing the greatest energy burdens are also among those most likely to face disconnections. While the Manitoba survey found only a weak overall relationship between arrears and energy poverty, it also showed that within the subset of

customers who are in arrears, those with lower incomes face higher energy burdens. In other words, income is a key determinant of risk once arrears occur.

These findings are consistent with broader international body of research linking energy insecurity, income, and disconnections.

Large-scale analysis of 300,000 low-income households in California (2012–2017) found that each additional day with a maximum temperature above 95 °F increased electricity expenses by 1.6% in that billing period and increased the relative risk of disconnection for non-payment by 1.2% within approximately two months. The authors estimated that under projected end-century climate conditions, the average risk of disconnection could rise by about 12% (Barreca et al., 2022).⁶

Using national data from U.S. households, Hernández and Laird (2022)⁷ show that energy disconnections are stratified by income, race and ethnicity, and housing quality. Nearly 15% of households received disconnection notices, and 3% experienced shut-offs, and this was noted to be a conservative estimate. Of those earning under \$20,000 annually, 4% received disconnection notices almost every month, compared to 2.7% for those with household income of \$20,000 to \$39,999, 1.3% for those with household income of \$40,000 to \$59,999, 2.2% for those with household income \$60,000 to \$79,999 and 0.3% for those with household income of \$80,000 or more. It should be noted that disconnections are often underreported.

Of those with household income less than \$20,000, 7.9% in 2015, compared to 2.9% for those with household income of \$20,000 to \$39,999, 2.5% for household making \$40,000 to \$59,999, 1.1% making \$60,000 to \$79,999, and 0.6% for those with household income of \$80,000.

The study overall finds, “Disconnections are disproportionately high among households with low incomes, a Black head of household, a head who does not have a high school diploma, mobile homes, older homes, poorly insulated homes, rentals, rural homes, and homes in the Northeast” (p.864).

Flaherty, Carley, and Konisky (2020)⁸ show that U.S. disconnection policies often fail to protect the same groups that experience the highest energy burdens—low-income, elderly, racialized, and rural households. The authors emphasize that even modest arrears can trigger loss of service with serious health risks, especially under extreme temperatures.

⁶ Barreca, A., Park, R.J. & Stainier, P. High temperatures and electricity disconnections for low-income homes in California. *Nature Energy* 7, 1052–1064 (2022). <https://doi.org/10.1038/s41560-022-01134-2>.

⁷ Hernández, D., & Laird, J. (2022). Surviving a shut-off: US households at greatest risk of utility disconnections and how they cope. *American Behavioral Scientist*, 66(7), 856-880.

⁸ Flaherty, M., Carley, S., & Konisky, D. M. (2020). *Electric utility disconnection policy and vulnerable populations*. *The Electricity Journal*, 33(10), 106859. <https://doi.org/10.1016/j.tej.2020.106859>.

Recent work by Baker, Carley, and Konisky (2021)⁹ reinforces that energy disconnections disproportionately affect low-income and racialized households. Their analysis shows that, during the first year of the COVID-19 pandemic, energy insecurity worsened, particularly for low-income, racialized, and vulnerable households. Early disconnection moratoria provided temporary relief, but most have since expired.

- b) Yes. It is reasonable to conclude that the Neighbours Helping Neighbours (NHN) program's participation limitations are partly related to its eligibility criterion excluding individuals receiving social assistance.

Under **The Manitoba Assistance Act (s. 5.3.1 (1))**, shelter benefits are intended to include essential utility costs such as electricity and heating. This framework may explain why Manitoba Hydro's NHN program currently excludes income assistance recipients, on the assumption that these households already receive support for utility expenses.

However, in practice there are **gaps between theoretical coverage and actual household energy costs**. Shelter benefit amounts are typically fixed and may not reflect seasonal variation, arrears accumulation, or the higher energy burdens faced by low-income or remote households. As a result, some income assistance recipients can still experience **bill payment challenges and risk of disconnection**, yet remain ineligible for NHN support.

Excluding these households from NHN effectively omits some of the most financially vulnerable customers from accessing emergency bill support.

In addition, participation challenges extend beyond income eligibility. Uptake has been concentrated among Winnipeg renters, while participation on First Nations reserves has been low due to administrative barriers, lower program awareness, and logistical challenges in completing applications. In recent years, NHN has supported approximately 580 households in 2022/23 and 395 households in 2023/24. Because NHN relies on fixed annual contributions from Manitoba Hydro and customer donations, funding availability is limited each year. In some years, the program has been fully subscribed before year-end, leaving otherwise eligible households without support.

Together, these factors—restricted eligibility, uneven geographic reach, and funding constraints—limit the program's overall effectiveness in addressing bill affordability for the province's most energy-vulnerable households. Expanding eligibility to include social assistance recipients, improving outreach on First Nations, and ensuring stable annual funding would strengthen NHN's accessibility and impact.

⁹ Baker, S. H., Carley, S., & Konisky, D. M. (2021). *Energy insecurity and the urgent need for utility disconnection protections*. *Energy Policy*, 159, 112663. <https://doi.org/10.1016/j.enpol.2021.112663>.

- c) Not necessarily. Expanding crisis support and arrears management tools does not inherently require new funding that would raise rates for low-income customers. Many interventions can be structured to be cost-neutral or even cost-saving through reduced collection costs and avoided disconnections. Moreover, as Oppenheim (2016)¹⁰ note, energy poverty is a multidimensional problem that cannot be solved solely through pricing or rate mechanisms; effective solutions require coordinated policy tools that integrate income support, energy efficiency, and consumer protection.

Within this framework, enhanced arrears and crisis-support programs represent an important component of a balanced affordability strategy, rather than a source of upward pressure on rates.

- d) Clarifying the expanded arrears-management tools sought (relative to current MH/EM/government and community-based supports)

The report's recommendation to maintain and adapt arrears management tools builds on Manitoba Hydro's existing programs, including the Customer Arrears Assistance Plan, payment arrangements, and the Neighbours Helping Neighbours (NHN) program, which collectively provide important support to customers facing payment difficulties. The goal is to refine these tools so repayment terms are realistic and do not merely defer inevitable defaults, while connecting customers to programs that reduce future arrears risk.

An expanded approach could include:

- Early identification and outreach to households at high risk of arrears (e.g., those with repeated payment arrangements, medical vulnerabilities, or high energy burdens);
- Automatic referrals to Efficiency Manitoba's programs so households receiving arrears assistance or NHN grants can also access energy-efficiency upgrades and long-term bill reductions; and
- Stronger coordination with community and government supports, such as social-assistance caseworkers, Indigenous organizations, and non-profits providing emergency aid.

Together, these refinements would make arrears management more proactive, integrated, and effective—linking immediate crisis relief through NHN with sustained affordability improvements.

¹⁰ Oppenheim, J. (2016). The United States regulatory compact and energy poverty. *Energy Research & Social Science*, 18, 96-108.

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| Part and Chapter: | CC-20 (Dr. Das Report) | Page #: | 36, 38, 41 |
| Topic: | Bill Affordability | | |
| Subtopic: | Manitoba Hydro Offerings | | |

Preamble (if any):

At p. 36, Dr. Das states:

Low-income households, Indigenous households – particularly First Nations on reserve – renters, and residents of older or electrically heated dwellings face the greatest risks. Without targeted affordability measures, these households will bear the brunt of uniform rate increases, exacerbating already high energy burdens and deepening conditions of energy poverty. These compounding effects underscore the need for targeted analysis – that is, analysis showing how energy burdens and bill impacts vary across income groups and household types – rather than relying on “average” bill impacts alone.

Pages 38 and 41 also state the following:

[p. 38] Hydro evaluates its affordability programs largely through participation rates, repayment performance, and continuity of service (i.e., disconnection avoidance). However, long-term outcome evaluations are lacking. A robust evaluation would track whether programs reduce household energy burdens over time, establish a baseline for participants, and measure outcomes such as improved affordability, reduced arrears recurrence, or enhanced comfort and health. Without these metrics, it is difficult to know whether programs provide sustained relief or merely delay disconnection.

[p.41] Manitoba Hydro currently assesses affordability programs mainly through participation and repayment metrics. While useful, these do not indicate whether programs provide lasting affordability relief. The Public Utilities Board should require Hydro to adopt outcome-based evaluation frameworks that track impacts on household energy burdens, arrears recurrence, and service continuity over time.

Question:

Please further explain whether the recommended outcome-based program evaluation necessarily requires Manitoba Hydro to track and store specific customer household income levels, as opposed to obtaining self-reported household income levels from a sample of customers, who may not have a history of arrears, through the periodic Residential Energy Use Survey.

Rationale for Question:

To better understand the report's recommendations.

Response:

In my view, Manitoba Hydro should make reasonable efforts to collect voluntary, self-reported household income data from its customer base to improve the evaluation of affordability programs. Similar to census-type reporting, this information would help identify how energy burdens and bill impacts vary across income groups and regions, informing better long-term policy and program design. While participation could not be mandatory, voluntary collection with appropriate privacy protections would strengthen the evidence base for affordability planning.

If income data are obtained through surveys rather than directly from customers, it is important that probability sampling methods be used to ensure results are statistically representative and generalizable—especially of hard-to-reach, Indigenous, or high-burden households who are often underrepresented in voluntary surveys. A comprehensive or probability-based dataset would therefore provide a more accurate picture of energy affordability challenges and program outcomes over time.

PUB/Coalition I-6

| | | | |
|--------------------------|--------------------------|----------------|--------------|
| Part and Chapter: | CC-20 (Dr. Das Report) | Page #: | 23-29, 38-39 |
| Topic: | Bill Affordability | | |
| Subtopic: | Manitoba Hydro Offerings | | |

Preamble (if any):

In Order 101/23, stemming from the 2023/24 & 2024/25 Manitoba Hydro GRA, the Board made recommendations to both Manitoba Hydro and the Province of Manitoba regarding bill affordability and energy poverty programs. These recommendations followed several other bill affordability-related directives and recommendations issued by the Board in relation to a number of Manitoba Hydro proceedings that were completed before that time.

At pages 38-39 of the report, Dr. Das cites various affordability programs offered elsewhere in Canada (these are also outlined in Table 2 at pages 23-29 of the report). In addition to citing various income-qualified energy efficiency program offerings, the Ontario Electricity Support Program (OESP) and Low-Income Energy Assistance Program (LEAP) available in Ontario are referenced. Dr. Das then submits that “These examples show that many utilities across Canada provide ongoing bill credits or no-cost retrofit programs that directly target low-income households and reduce energy burdens over the long term. By contrast, Manitoba Hydro’s programs remain limited in scale and oriented toward short-term payment management rather than structural affordability.”

Question:

- a) Please explain what entity (or entities) administer the Ontario Electricity Support Program and Ontario’s Low-Income Energy Assistance Program, including who assesses the prospective customer’s household income level against the established program eligibility thresholds.
- b) Please indicate who funds each of the programs.
- c) Are there any specific programs on the list that Dr. Das recommends for Manitoba?
- d) Are there any programs on the list that are particularly successful in reducing energy poverty? If so, please elaborate and indicate Dr. Das’ opinion as to why those programs are successful.
- e) Please explain, at a high level, what would be required to conduct an energy poverty study in Manitoba that would identify the specific demographic challenges this in this province.
- f) Please further explain the necessary changes and interactions between Manitoba Hydro, Efficiency Manitoba, the Province of Manitoba (and others, if applicable) to further develop or implement the energy poverty-related recommendations outlined in the report.

Rationale for Question:

To better understand the various energy bill affordability programs currently available in Canada and the report's recommendations regarding improvements in Manitoba.

Response:

- a) Both the Ontario Electricity Support Program (OESP) and the Low-Income Energy Assistance Program (LEAP) are administered by the Ontario Energy Board (OEB), Ontario's independent electricity and natural gas regulator.

For OESP, customer eligibility and income verification are managed by the program's central service provider, which verifies household income either directly through the Canada Revenue Agency (CRA) (with consent) or via documentation reviewed by an authorized community intake agency.

For LEAP, applications are assessed by designated intake agencies—typically community organizations or United Way partners—who verify income against OEB-established thresholds.¹¹

- b) Both programs are funded through ratepayer-supported mechanisms approved by the OEB:
- The costs of the OESP are recovered from all electricity customers in Ontario and all wholesale market participants, including distributors, pay a per-kilowatt charge to the IESO to fund the OESP. Distributors pass this charge on to their customers (except any customers who are direct market participants and therefore already pay the charge to the IESO). The charge was set for the first time in the OEB's November 19, 2015 Decision and Order on Regulatory Charges.¹²
 - LEAP: Each electricity and natural gas distributor (together, distributors) provides the greater of 0.12% of their total OEB-approved distribution revenue or \$2,000 each year for LEAP EFA. Distributors may only use their LEAP EFA funds for their own customers residing within the distributor's service area. Neither program is funded through general provincial revenues; however, the Ontario Ministry of Energy provides overall policy direction within which the OEB operates.¹³

¹¹ Sources: OEB Website: <https://www.oeb.ca/consumer-information-and-protection/bill-assistance-programs/ontario-electricity-support-program>; <https://www.oeb.ca/consumer-information-and-protection/bill-assistance-programs/low-income-energy-assistance-program>.

¹² https://www.oeb.ca/oeb/Documents/Documents/OESP_Guideline_Distributors_USMP.pdf

¹³ OEB Staff Report, November 21, 2023

<https://www.oeb.ca/sites/default/files/uploads/documents/reports/2023-11/OEB-LEAP-EFA-Report-20231121.pdf>

- c) Leaving aside existing statutory limitations in the *Manitoba Hydro Act*¹⁴, I recommend drawing from three established Canadian programs to inform Manitoba's approach to bill affordability and energy poverty:
1. Ontario Electricity Support Program (OESP) – Provides a monthly on-bill credit for income-qualified electricity customers. This approach offers predictable, sustained relief and directly reduces measured energy burdens.
 2. Low-Income Energy Assistance Program (LEAP, Ontario) – Provides one-time emergency financial assistance to customers in arrears or at risk of disconnection. It is similar to Manitoba Hydro's Neighbours Helping Neighbours program but benefits from stable, ratepayer-funded contributions mandated by the Ontario Energy Board.
 3. The Home Energy Assistance Top-Up (HEAT) Fund model is particularly relevant to Manitoba's context. Given the province's long, cold winters and high heating-energy requirements, households experiencing energy poverty often struggle most with heating costs. A HEAT-style program—providing targeted, emergency heating and electricity assistance through a coordinated provincial–utility partnership—would help address seasonal affordability challenges more effectively. This model could complement Manitoba Hydro's existing Neighbours Helping Neighbours program by adding a stable, multi-partner funding stream dedicated to heating-related hardship.
- d) There is limited publicly available evidence to determine which specific programs in Canada have been most successful in reducing energy poverty, as formal program evaluations are rare and outcome-based data are often unavailable. Most jurisdictions report participation numbers or disconnection avoidance but do not track long-term changes in energy burden, arrears recurrence, or household well-being.

Nevertheless, programs such as Ontario's Ontario Electricity Support Program (OESP) and Low-Income Energy Assistance Program (LEAP) are generally regarded as promising models, because they combine clear eligibility criteria, regulated funding mechanisms, and integration with broader affordability policies.

However, without consistent evaluation frameworks—such as those tracking household-level energy burdens before and after participation—it is not yet possible to conclude which models most effectively reduce energy poverty in a sustained way. Strengthening evaluation practices across jurisdictions would be an important next step toward identifying measurable success.

- e) A Manitoba energy poverty study would require a clear measurement framework (e.g., 10%, 2M) and integrated data linking Manitoba Hydro billing and

¹⁴ *The Manitoba Hydro Act*, CCSM c H190, s 39(5)5.

consumption records with income, housing/dwelling, and demographic data (potentially sourced from Statistics Canada, and the CMHC).

If survey data are collected, probability sampling should be used to ensure representation of all Manitobans and potentially oversampling of low-income, rural, northern, and on-reserve households, who are often underrepresented in voluntary surveys. Collaboration with First Nations and Métis organizations is essential to align with data sovereignty principles.

- f) Addressing energy poverty in Manitoba will require strong coordination and clear roles among Manitoba Hydro, Efficiency Manitoba, and the Province.
- Manitoba Hydro should continue to deliver bill affordability and arrears management programs (e.g., payment arrangements, Neighbours Helping Neighbours), while expanding proactive outreach and linking these supports directly to Efficiency Manitoba's retrofit programs.
 - Efficiency Manitoba should scale and adapt its income-qualified and Indigenous energy-efficiency offerings, aligning eligibility and referral processes with Hydro's affordability initiatives to ensure households receiving crisis or arrears support can also access structural efficiency upgrades.
 - The Province of Manitoba should provide policy direction and stable funding mechanisms for ongoing affordability supports, such as an on-bill credit or regulated low-income fund (similar to Ontario's OESP or LEAP), and facilitate data-sharing agreements between agencies.

Partnerships with Indigenous governments, municipalities, and community organizations will be essential for program delivery, outreach, and culturally appropriate engagement.

PUB/Coalition I-7

| | | | |
|--------------------------|------------------------|----------------|----|
| Part and Chapter: | CC-20 (Dr. Das Report) | Page #: | 33 |
| Topic: | Bill Affordability | | |
| Subtopic: | | | |

Preamble (if any):

Page 33 of the report states:

Indigenous households, particularly First Nations on-reserve, face the highest burdens in the province. Manitoba Hydro's survey shows that 38.4% of on-reserve households exceed the 10% burden threshold, with an average burden of 9.7%. For Indigenous households overall, 13.7% exceed the threshold, compared to just 2.8% among non-Indigenous households. These disparities highlight how structural inequities in income, housing quality, and energy infrastructure amplify affordability risks.

In prior Manitoba Hydro proceedings, the Board has heard evidence regarding high energy usage in Northern on-reserve First Nations communities, in part due to the energy efficiency of the existing housing stock, as well as due to the longer and colder winters generally faced by these customers compared to those living in Southern Manitoba. In addition, the Board has previously heard evidence regarding on-reserve First Nations customers affordability issues, including jurisdictional issues related to housing and the payment of energy bills (e.g., a third party, such as the local band or an agency acting on behalf of the Government of Canada, is sometimes responsible for either the full or a portion of the customer's energy bills).

Question:

Please provide additional evidence or research findings regarding the issue of payment responsibilities for on-reserve First Nations customers and the related impact on the assessment of the energy burdens of on-reserve First Nations customers.

Rationale for Question:

To better understand the issues of bill affordability for on-reserve First Nations customers.

Response:

There is limited published research directly quantifying how third-party payment arrangements affect measured energy burdens for on-reserve First Nations households. However, it can be reasonably inferred that these arrangements often redistribute or mask affordability pressures rather than eliminate them.

According to the 2021 Census¹⁵, shelter costs for households living in dwellings provided by a First Nation or local government include payments for electricity, heat, water, and other services, along with regular monthly payments for use or occupancy of the dwelling. This indicates that energy costs may be embedded within housing payments rather than billed directly to households, complicating measurement of household-level energy burden.

Research on Indigenous energy systems (e.g., Rezaei & Dowlatabadi, 2016¹⁶) notes overlapping governance and jurisdiction on energy matters. Consequently, reported energy-burden levels for on-reserve households likely underestimate the true affordability challenge. Even when households are not directly responsible for utility payments, low incomes, poor housing insulation, reliance on electric resistance heating, and long northern winters all contribute to high energy needs and persistent vulnerability.

¹⁵ Statistics Canada. A first look at shelter costs for households living on reserve using new data from the 2021 Census. <https://www150.statcan.gc.ca/n1/pub/46-28-0001/2022001/article/00002-eng.htm>.

¹⁶ Rezaei, M., & Dowlatabadi, H. (2016). Off-grid: community energy and the pursuit of self-sufficiency in British Columbia's remote and First Nations communities. *Local Environment*, 21(7), 789-807.

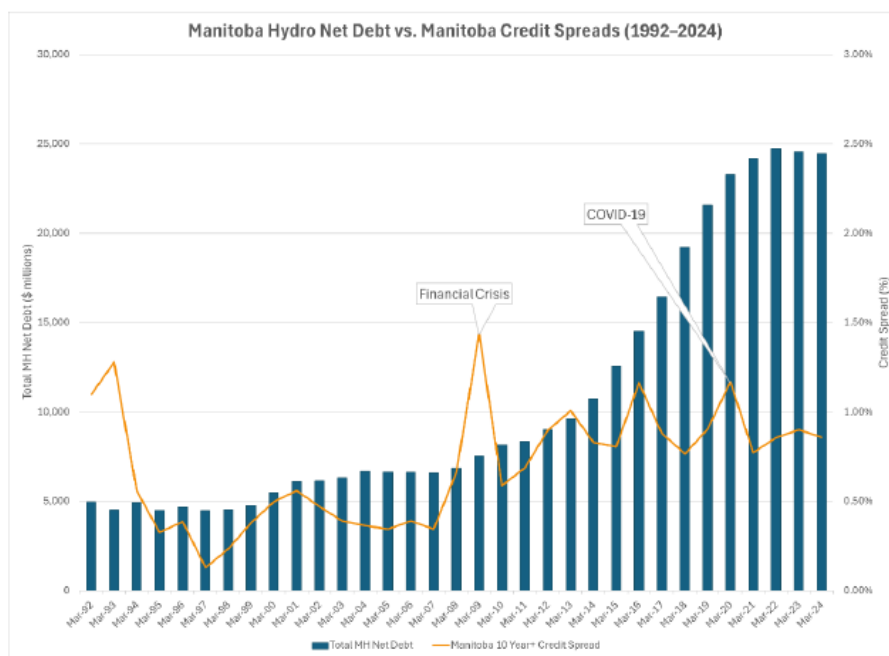
PUB/Coalition I-8

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|--------------------------|--|----------------|----|
| Part and Chapter: | CC-15 (MPA Report) | Page #: | 17 |
| Topic: | Manitoba Hydro Financial Risk Management | | |
| Subtopic | | | |

Preamble (if any):

At p. 17, Morrison Park Advisors (“MPA”) provide a chart depicting the spread in costs between Manitoba “long bonds” and Canada long bonds, over the period of March 1992 to March 2024. The chart also presents Manitoba Hydro’s total debt at the end of each fiscal year during this period. The chart is reproduced as follows:

Figure 3



Question:

- a) Please comment on the impact, if any, of PUB-approved rate increases for Manitoba Hydro during that period, and whether those rate increases play a role in MPA’s conclusion that the credit spread has not materially changed.
- b) Please overlay on the figure (or provide a new figure) the provincial credit spreads for British Columbia, Saskatchewan, Manitoba, Ontario, Quebec and New Brunswick.

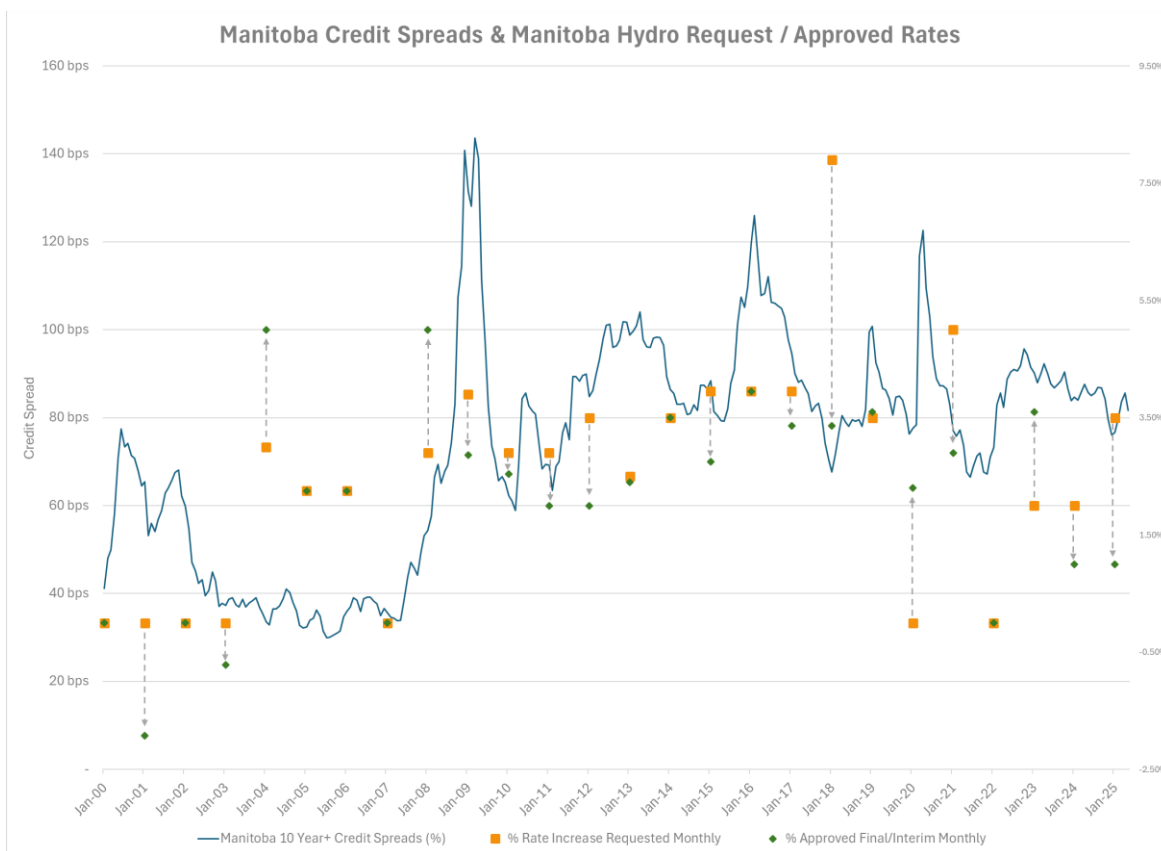
Rationale for Question:

To better understand the factors considered in this chart.

Response:

a) Yield spreads and rate increases

The following chart superimposes the history of Manitoba Hydro rate increase requests, and the PUB’s rate increase decisions, on the Manitoba-Canada yield spread curve (average of 10-year and 30-year) since the year 2000.

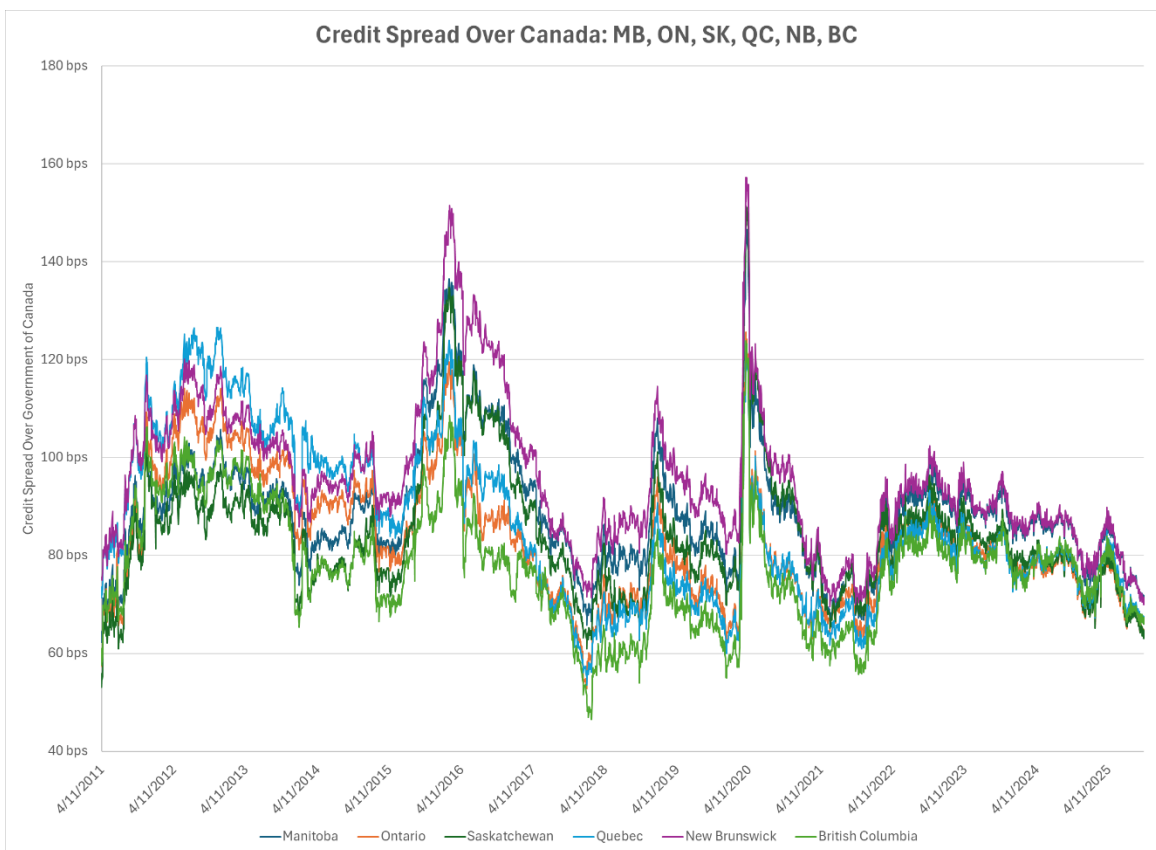


In a majority of cases, the PUB approved rates that were less than the increases requested by Manitoba Hydro. It might be assumed that following such instances, a negative market reaction would have resulted in the weeks immediately following the decision. Similarly, where the PUB granted Manitoba Hydro requests in full, or even approved rates that were higher than requested, it might be assumed that yield spreads would come down. Unfortunately, none of these relationships appear to be evidenced consistently over the past 25 years. Any consistency with such crude predictions appears to be coincidental, as the shape of the yield curve appears to be influenced by macro-economic considerations, rather than local factors (as will be made more clear below).

b) Comparison with other provinces

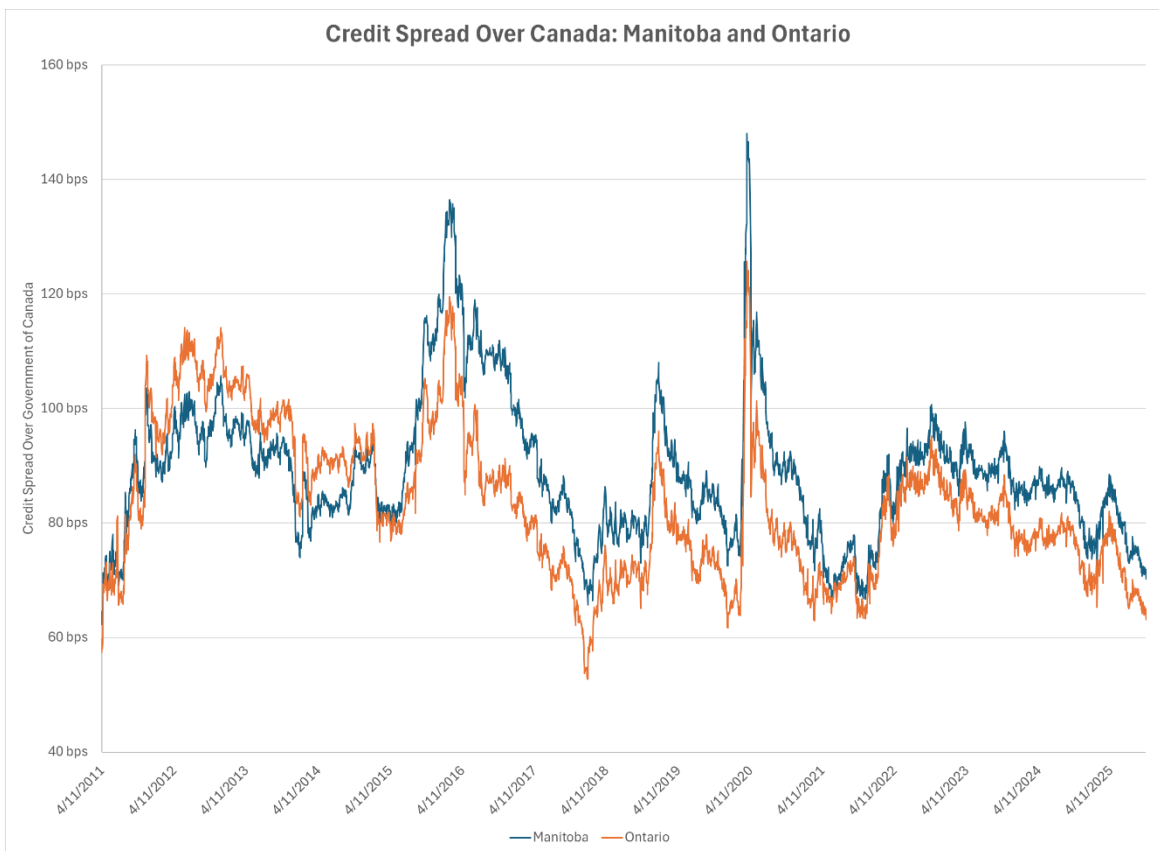
Comparative data for provincial credit spreads was available through the Bloomberg financial information service, but only as far back as 2011. While this does not equate to the Manitoba information dating back to 1992 that was made available by Manitoba Hydro as part of this GRA process, the comparison of different provinces' yield spread curves (compared to Canada) over the past 15 years is nevertheless instructive [Note: data supporting the figures in this reply to the PUB information request is provided in MPA Attachment 1].

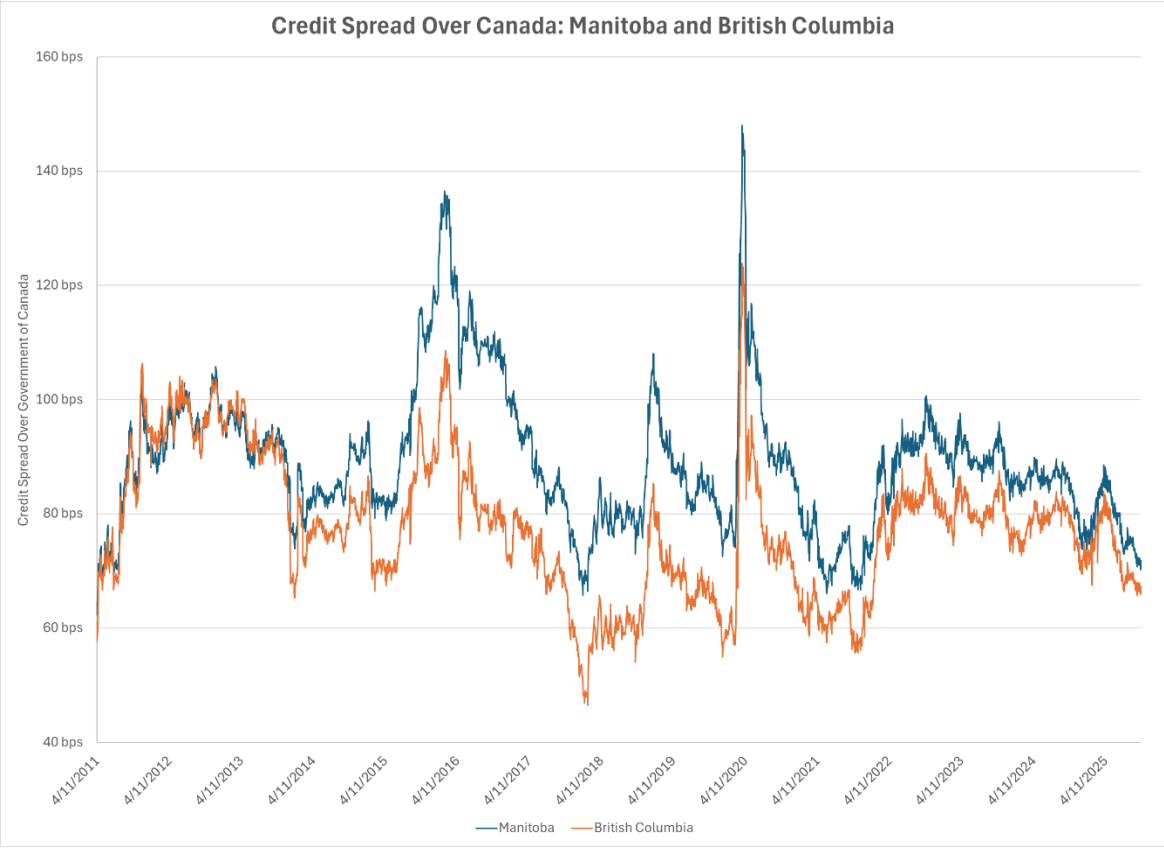
The following chart depicts the yield spread curve (average of 10-year and 30-year) for 6 provinces, including Manitoba. What is remarkable about this chart is the consistency of the overall shape of the provincial-to-Canada yield spread curves. This consistency in shape suggests that the major driver for changes in provincial yield spread curves is overall macro-economic conditions and events, and not factors local to individual provinces (like the level of Manitoba Hydro debt in Manitoba). Local factors are important, but they explain the differences between individual provincial curves, rather than the overall changes in the curves over time.

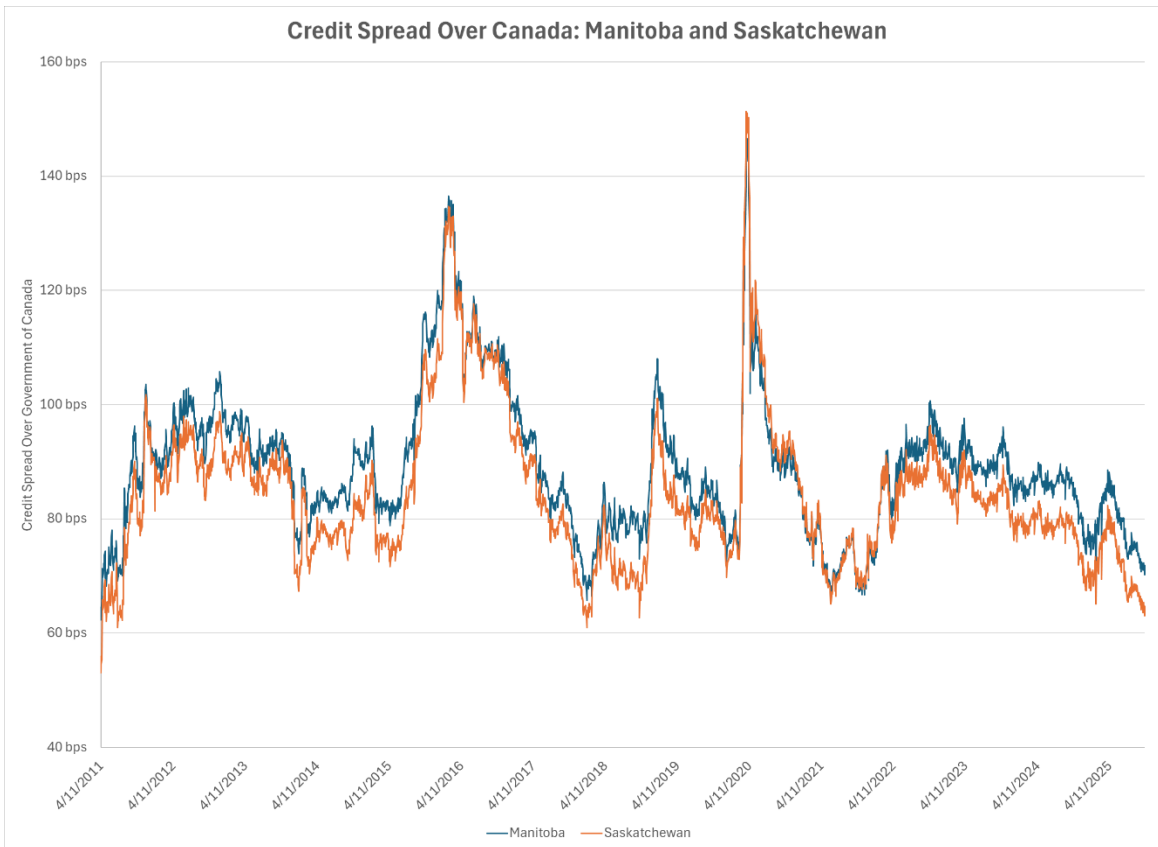
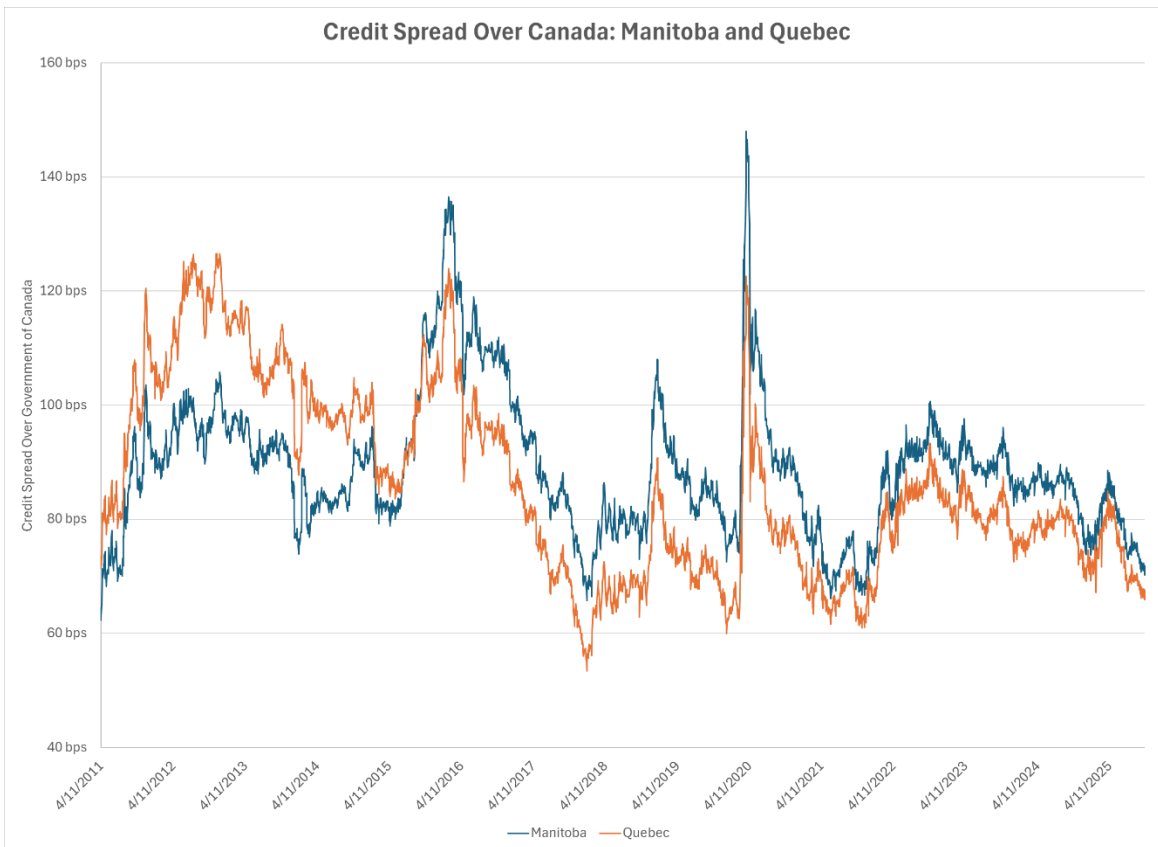


To further illustrate this point, below are presented individual graphics for Manitoba and each of the other provinces separately. The difference between Manitoba and other provinces is evidenced by the vertical separation between the curves, which

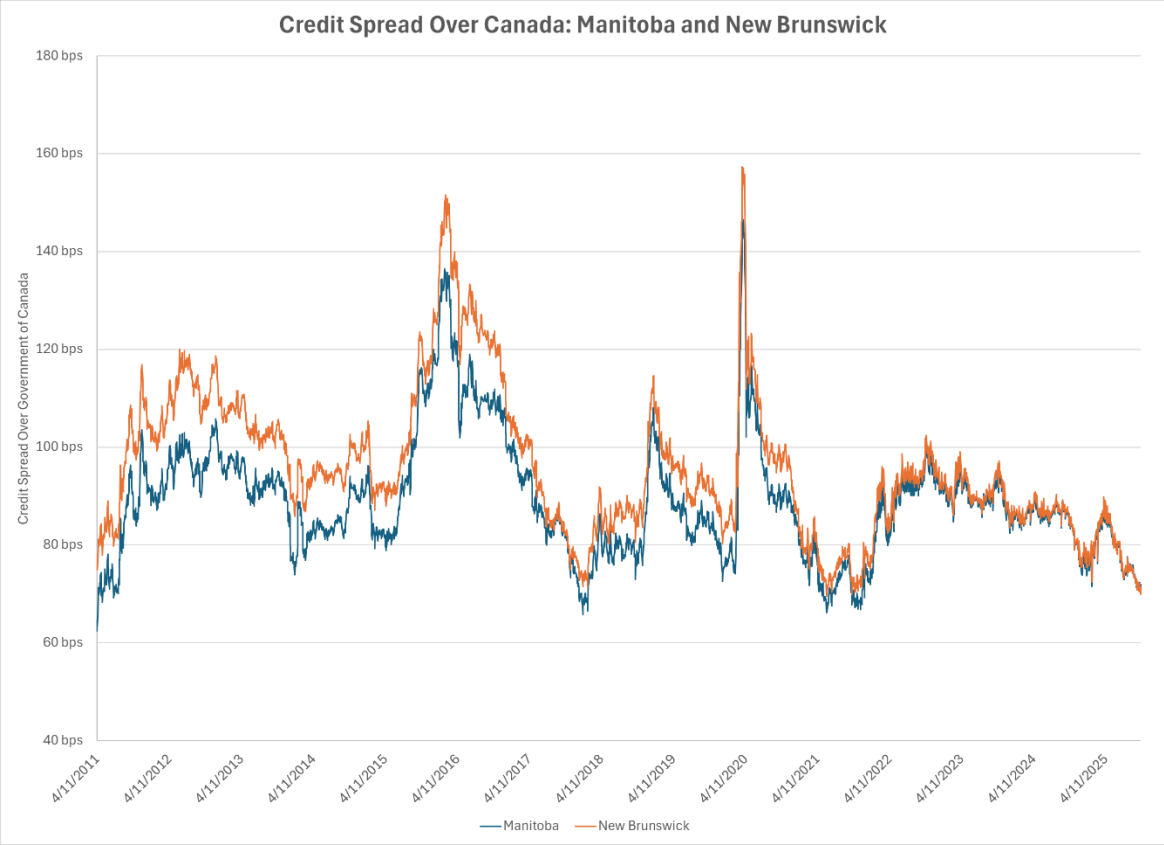
may change slightly over time. This change in relative separation could occur because of something that occurred in Manitoba, or in the other provinces, or both. Analyzing in detail the comparative financial and economic performance of different provinces in Canada over a 15-year period is beyond the scope of MPA's work in this GRA. However, the consistency over time in the shape of the Manitoba yield spread curve as compared to the yield spread curves of other provinces, as well as the consistency in the separation between Manitoba and other provinces, suggests that the changing levels of Manitoba Hydro debt have not had a substantial influence (if any!) on Manitoba yield spreads (noting that over the course of the 15 years covered by these charts, Manitoba Hydro debt increased substantially, yet there was no significant deterioration in Manitoba's absolute or relative yield spread performance, as compared to other provinces).







Manitoba Hydro Fiscal 2026-2028 General Rate Application
PUB/Coalition Information Requests
October 15, 2025



PUB/Coalition I-9

| | | | |
|--------------------------|--------------------|----------------|-------|
| Part and Chapter: | CC-15 (MPA Report) | Page #: | 17-19 |
| Topic: | Credit Spreads | | |
| Subtopic | | | |

Preamble (if any):

In reference to the spread in costs between Manitoba long bonds and Canada long bonds, MPA notes on page 18, lines 2-3, in reference to Figure 3 on page 17, that “there is no obvious relationship between the credit spread and the significant increase in Manitoba Hydro debt”.

MPA goes on to say on page 19, lines 4-5, that “The relevance of these charts and analysis is that there is no evidence that Manitoba Hydro’s debt-to-capitalization ratio affects either the availability or cost of Manitoba debt”.

Question:

- a) While MPA notes there is no ‘obvious’ relationship between the credit spread and the increase in Manitoba Hydro debt, it appears that aside from the financial crisis of 2008, the credit spread increases with increased Manitoba Hydro debt. What is the relationship if statistically assessed, both including and excluding the 2008 financial crisis anomaly?
- b) If there is a correlation between the credit spread and the increase in Manitoba Hydro debt, how does that alter your testimony relating to the availability or cost of Manitoba debt?
- c) What is the relevant of PUB-approved rate increases during the period in which debt increased? In particular, would spreads have increased without regular approved rate relief?

Rationale for Question:

Response:

Response to Questions a) and b):

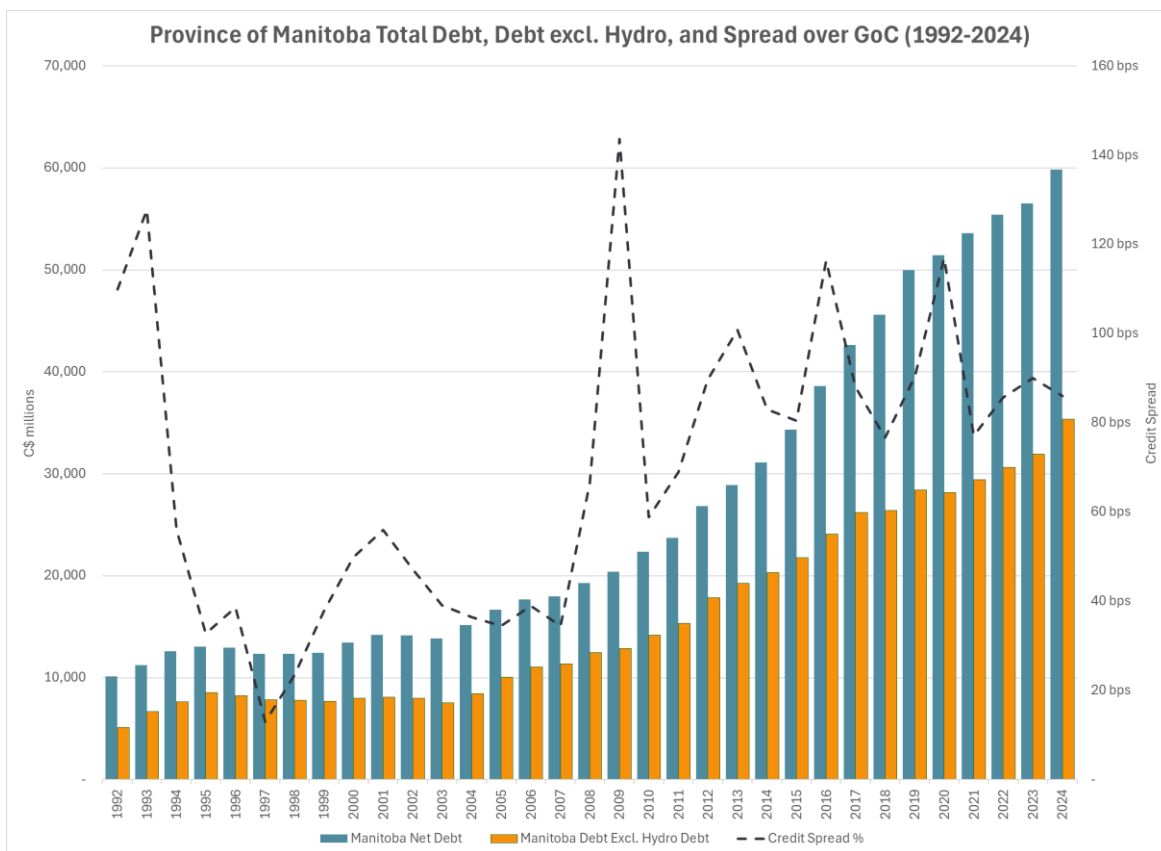
Province of Manitoba bonds trade daily, with constantly fluctuating prices. Manitoba Hydro debt levels are reported only periodically, and for the purposes of our analysis only annual net debt levels were considered. Comparing a daily curve and an annual curve will yield virtually zero correlation (on a least squares basis), just based on the math involved.

If the analysis is limited to yield spreads in March of every year, and Manitoba Hydro net debt levels reported for each year end as of March 31, then correlation can be calculated (note, however, that Manitoba Hydro releases its annual report somewhere between two and four months after year end, so information about debt levels is not actually made public in March or April. The choice of which month of the year to focus on for the analysis of correlation is therefore somewhat arbitrary).

Considering the full range of the period March 1992 to March 2024, there is a 46% correlation between debt levels and the Manitoba yield curve (i.e., the general upward curve of debt levels has a modest correlation with a yield curve which is higher between 2011 and 2024 than it was from 1995 to 2007). If the very anomalous March 2009 figure is removed from this analysis, then the correlation increases to 54%. This seems to suggest that there is some correlation between the higher Manitoba Hydro debt levels of the past 15 years, and a somewhat higher general level of the yield curve, considered on a very broad span of years.

However, if the analysis is limited to the period 2011 to 2024 (i.e., post-financial crisis to near the present day), the correlation between Manitoba Hydro debt levels of the yield curve falls to 10% (i.e., almost completely uncorrelated). This is relevant because the decision to pursue the Keeyask project – and dramatically increase Manitoba Hydro debt – was taken after the beginning of this period. In other words, the dramatic surge in Manitoba Hydro debt appears to be uncorrelated with the yield spread curve in any meaningful way. Moreover, we know from the answer to PUB/Coalition I-8, above, that the yield spread curve for Manitoba very closely follows the shape of the yield spread curve for other provinces in Canada over this period, which is another argument in favour of there being limited if any relationship between Manitoba Hydro debt levels and the yield spread curve.

Additionally, when considering Province of Manitoba bonds and the yield spread curve compared to Canada, it is likely advisable to consider the overall debt level of Manitoba, and the level of Manitoba's debt that is not related to Manitoba Hydro. The following chart depicts Manitoba's overall debt level, as well as the portion of that overall debt that is not derived from Manitoba Hydro.



As can be seen in the above chart, more than half of the Province of Manitoba’s total debt is made up of non-Hydro debt (i.e., Manitoba Hydro is responsible for less than half of the total debt of the province, and always has been). Over the timespan from 1992 to 2024, the correlation between Total Debt and the yield spread curve is 48% (vs. 46% for Manitoba Hydro debt), and the correlation between non-Hydro Debt and the yield spread curve is 50%. These differences in levels of correlation are so small as to be not statistically significant, considering the crude nature of the data (i.e., annual debt levels vs. public bond yields that change daily).

When narrowing the scope to the 2011 to 2024 period, the degree of correlation falls dramatically for Total Debt and non-Hydro Debt, just as it did for Manitoba Hydro Debt – 11% and 12%, respectively.

Finally, the jump in federal-provincial yield spread after the financial crisis was shared by every province in Canada to almost the same degree (approximately 50 basis points for 10-year bonds), regardless of the particular path of their debts. The yield spread for every province in Canada was relatively low during the period 2000 to 2007 (pre-financial crisis), and was approximately 50 basis points higher between 2010 and 2017 (post-financial crisis) regardless of the degree of change in provincial debt levels.¹⁷

¹⁷ Please see “Decomposing Provincial-Canada Yield Spreads: Does Fiscal Discipline Matter?”, in Fall 2018 issue of the newsletter of The Institute of Fiscal Studies and Democracy, University of Ottawa, page 10. ([ifsd-Decomposing-provincial-canada-yield-spreads-fall-2018](#)) Between 2000 and 2007, all provinces

As was noting in response to PUB/Coalition I-8, there is a very high degree of correlation in the yield spread curves of provinces across Canada, and this was just as true before the financial crisis as it was after.

In summary, while there does seem to be some correlation in the broad sweep of the yield curve and debt levels over the course of more than 30 years, during the recent 15-year period of very significant increases in Manitoba Hydro debt (and Province of Manitoba non-Hydro debt) there is almost no correlation. Moreover, the consistency in yield curves with other provinces, both before and after the financial crisis, is another reason to discount any perceived correlation between Manitoba Hydro debt levels and the yield premium above Canada paid by Manitoba.

Response to c): Would spreads have increased without rate increases?

In the past, the PUB has made decisions about rate increases which were based on rational economic/regulatory policies, and the facts of the various General Rate Applications made by Manitoba Hydro. Speculating about what might have happened had rate increases not been approved is at best an academic exercise.

MPA has argued in previous appearances before the PUB that capital markets prefer regulatory consistency and a focus on economic rationality and facts. Since fiscal prudence is a critical principle of regulation in Manitoba, and the PUB has chosen to approve rate increases that are calibrated to support the ability of Manitoba Hydro to pay its debt obligations while not placing undue burdens on ratepayers, we have argued that no damage has been done to either the Province's ability to raise capital (for both itself and Manitoba Hydro) or to the price of that capital. However, if sensible rate increase decisions had not been made consistently, as they have been in the past, then this trend could easily have been broken, to ill consequences.

In short, MPA believes that it is not Manitoba Hydro's debt level which drives the opinions of the capital markets, but the likelihood that the debt will be serviced. Since rate increases in the past have been consistent with Manitoba Hydro's ability to service its debt – and hopefully will continue to be so in the future – then capital markets have been satisfied. Were the PUB to ever declare or demonstrate that its rate increase decisions are NOT meant to ensure sufficient ability to service debts, then the reaction of the capital markets should be expected to be swift.

had yield spreads with Canada that averaged between 26 and 47 basis points for 10-year bonds. Between 2010 and 2017, the average spread was between 76 and 103 basis points. Increases for each province ranged between a low increase of 42 basis points, and a high increase of 56 basis points. The consistency of the pre- and post-crisis yield spreads points to a nation-wide structural shift in fiscal policy and debt markets. For detailed information on debt levels in all provinces, please see the Federal Fiscal Reference Tables, which contain information back to 1990-91 ([Fiscal Reference Tables - Canada.ca](#)).

PUB/Coalition I-10

| | | | |
|--------------------------|-----------------------------------|----------------|-------|
| Part and Chapter: | CC-15 (MPA Report) | Page #: | 20-21 |
| Topic: | Financial Factors for Rate-Making | | |
| Subtopic | | | |

Preamble (if any):

In reference to the spread in costs between Manitoba long bonds and Canada long bonds, MPA notes on Page 20, Lines 9-13, in reference to Figure 5 on page 20 and prior Figures, that:

Not to belabour the point, but if credit rating agency reports on the Province of Manitoba cannot be shown to be related to the cost of Manitoba credit, then why should reports on Manitoba Hydro be considered determinative?

None of the foregoing comments are meant to suggest that the financial performance of Manitoba Hydro is unimportant to the credit-worthiness of the company itself, or perhaps more importantly, to the credit-worthiness of the Province of Manitoba.

MPA also summarizes four reasons for Manitoba Hydro’s requested rate increase on page 21, further summarized as follows:

- Increasing operating expenditures.
- Drought conditions.
- Capital expenditures.
- Manitoba Hydro’s “financial health”.

Question:

- a) Does MPA have a view as to what portion of the requested 3.5% annual rate increases relate to the financial health of the utility?
- b) If the debt-to-capitalization ratio were removed from the determination of rate increases, and replaced by other financial health metrics preferred by MPA, how much would the requested increase change from the requested 3.5%?

Rationale for Question:

To better understand the impact of altering the use of the credit spread and debt-to-capitalization ratio as a key financial metric.

Response:

Response to Questions a) and c):

If the 20-year financial forecast as filed with the Application as of March 28 were assumed to be reasonable (which we now know is not the case as a result of the persistent drought conditions in the Province, and other updates that have been made to the forecast), then all of the 3.5% increases in both 2026 and 2027 can only be supported by “financial health” arguments, while approximately half of the 3.5% increase requested in 2028 could be justified by increasing costs, and the other half by financial health concerns. This is made evident by the fact that, in the original reference forecast, neither of the increases in 2026 or 2027 is required to ensure that Manitoba Hydro would break even in those years (existing rates operating in the “reference scenario” of inflation rates, load growth, export prices, etc., would result in annual profit, without any increase in 2026 or 2027 rates).

This is not to say that MPA would support 0% rate increases, even under the original reference scenario conditions. As made clear in our Report (in section 5), MPA believes that all ratepayers over time should be making contributions to the sustained financial viability of the utility. In a unique utility like Manitoba Hydro, which faces severe variability in its revenues because of volatile hydro-electric production, this contribution is likely to be non-trivial. As we suggested, the starting point for this analysis could be a target contribution by ratepayers above the estimated “power at cost” over the course of a three-year rate period. If 0% rate increases were approved for the full three-year rate period, then existing rates – always under the original reference scenario provided in the application – would result in an average total contribution by ratepayers above estimated “power at cost” of approximately 4%. Would this be enough, even under the ideal conditions of the original reference scenario? We believe it is unlikely, but as we noted, we believe there should be a deliberate process to choose a guideline for future ratepayer contributions to Manitoba Hydro financial stability.

However, it should be noted that the Manitoba Hydro reference scenario from its application is no longer the ideal starting part for a calculation of appropriate rate increases. First, it is critical to address the questions raised about Manitoba Hydro’s spending plans (for example by Mr. Rankie and by Midgard Consulting). If Manitoba Hydro’s spending estimates are inappropriately high, then the estimate of “power at cost” should be reduced accordingly, which will directly affect the calculation of appropriate rate increases. Second, the financial results for 2024-25 are now known and publicly disclosed (EBIT:Interest was again below 1.0), and the 2025-26 fiscal year is more than half completed, with drought conditions having continued in Manitoba throughout that time.¹⁸ Manitoba Hydro has still not publicly released information on its expected production and financial results for the current fiscal year, but based on the lifting of redactions on certain

¹⁸ The Manitoba Drought Condition report as of August 31, 2025, states that on both a 3-month and 12-month basis, a majority of the province has experienced moderate to severe drought, through recent conditions improved as compared to earlier in the season. This suggests that 2025-26 hydroelectric production may again be below historically average levels. Please see [Environment and Climate Change | Province of Manitoba](#)

information requests (publicly released on October 8, 2025), it can be inferred that 2025-26 is now expected to be another below average year. This new information should be taken into account in determining an appropriate rate increase for 2026 (but not for 2027 or 2028, which should, as always, be assumed to be “normal” from a hydroelectric production perspective).

PUB/Coalition I-11

| | | | |
|--------------------------|--------------------------|----------------|-----------|
| Part and Chapter: | CC-15 (MPA Report) | Page #: | 21, 26-30 |
| Topic: | Intergenerational Equity | | |
| Subtopic | | | |

Preamble (if any):

In Figure 7 of its report, MPA provides a calculation of revenue as a premium to basis “power at cost” and concludes that Manitoba Hydro’s 3.5% rate path front-loads revenue.

MPA goes on to introduce a different approach for rate-making “with the premise that all ratepayers should contribute their fair share to the needs of financial risk management and reserves”, itemizing 5 steps in the alternative mechanism (page 28, line 10 to page 29, line 2).

Question:

- a) Please comment on the impact of the following on MPA’s proposal:
 - i) the principle of gradualism in rate-making; and
 - ii) the current 4.0% annual rate cap.
- b) MPA noted the inappropriateness of the capitalization-to-debt ratio being a key metric to gauge Manitoba Hydro’s financial health. What suite of financial metrics would MPA consider to be more relevant and applicable for a better gauge of Manitoba Hydro financial health, and how would they be incorporated into MPA’s proposed approach?

Rationale for Question:

To explore interplay between gradualism and intergenerational equity.

Response:

- a) Gradualism, rate-setting and rate caps

Stability and predictability of rates is an important principle of rate-setting, as noted in MPA’s Report. The application of this principle can result in “gradualism”, or the controlled change in rates over time in order to satisfy an expected large change in revenue requirement stemming from a one-time or otherwise concentrated investment in ratebase assets. The PUB and Manitoba Hydro have historically incorporated a particular notion of “gradualism” in rate-setting by relying on 20-year rate forecasts, and seeking to project “even annual” rate increases over a

long period of time in order to achieve a variety of targeted outcomes while maintaining predictability of rate increases.

In this formulation, gradualism is a worthy goal, but it must be balanced with other worthy goals, such as cost responsibility and inter-generational fairness. It should also be balanced against the unlikelihood of actually being accurate in a 20-year forecast! Projecting even-annual rates over a long period of time is a very different thing from actually achieving even-annual rate increases (each of the last several GRAs has included long-term even annual rate increase projections, but the specific rates were different every time, because they had to be to appropriately respond to updated conditions; this should be understood as a feature, not a bug).

Over the short-to-medium-term, gradualism implies avoiding sudden changes or spikes in rates, which is entirely appropriate, and should be part of the regular rate-setting process. However, over the longer term, the quest for rate-smoothing becomes inter-generational transfer of cost responsibility, whether intentional or not. An appropriate balance is not easy to achieve, but it is not clear that time and resources should be spent on this issue every three years in a GRA process. Adopting a more mechanistic approach to rate-setting, and focusing more clearly on the near-to-medium term, would also serve another principle of rate-setting, which is efficiency. Significant questions of inter-generational transfer of cost responsibility should more appropriately be addressed as part of Integrated Resource Planning, when large capital expenditure plans are carefully considered, and the possibilities for financing of the same can be thoroughly explored.

With respect to the existing 4% rate cap, we would note that this is approximately double the long-term target rate of inflation. As such, it appears to be a reasonable limit imposed by the government, and meant to enforce a degree of “gradualism” in rate changes. To be sure, such limits present challenges for planning and rate-setting, particularly with respect to large one-time capital expenditures that must be absorbed into rates. However, in the normal course of utility operations, outside of major investments that should be addressed in dedicated planning processes, it is hard to foresee the necessity for rate increases beyond double the rate of inflation.

b) Financial metrics

As noted in section 5 of our Report, MPA believes that the PUB should consider adopting a new strategy towards rate-setting, which focuses more attention on the near-to-medium term, and which is more mechanistic in approach, eschewing the arbitrariness that is inherent in 20-year forecasts.

Debt-to-capitalization ratios do not provide meaningful direction for near-term decisions on rates, but instead invite fanciful constructions of long-term projections. Instead, cash flow-based metrics, such as EBITDA:Interest and EBIT:Interest, and Net Income targets under specific reference conditions, can be useful metrics that can be calculated with some precision. In addition, as mentioned, we believe that scenario testing, particularly related to drought

conditions, should become a standardized part of rate-setting, as a check on the degree of contribution that ratepayers should make to ensure the financial viability of the utility.

As noted in our Report, we believe that construction and refinement of a new rate-setting process should be the result of collaboration between the PUB, Manitoba Hydro, and other stakeholders, and should not be undertaken lightly. The PUB and Manitoba Hydro have, for better or worse and over many years, relied on the heuristic of 20-year forecasts and debt-to-capitalization targets as a means to placing context around rate decisions, and this cannot be easily changed. MPA is extremely reluctant to suggest any shortcuts to a careful process of change.

PUB/Coalition I-12

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|--------------------------|---------------------------|----------------|----|
| Part and Chapter: | CC-15 (MPA Report) | Page #: | 23 |
| Topic: | EBIT vs. EBIDTA Cash Flow | | |
| Subtopic | | | |

Preamble (if any):

At page 3 of its report, MPA states that:

MPA has argued in past GRAs, and continues to maintain, that the critical determinant of financial health for a non-share capital, “power at cost”, government-guaranteed utility like Manitoba Hydro is the expected sufficiency of cash flows to pay the utility’s operating costs and debt service costs. With respect to metrics, this suggests the primacy of EBITDA:Interest and EBIT:Interest as indicators of financial capacity, from among those normally calculated by Manitoba Hydro.

Question:

Please explain whether additional mandatory annual payments, such as mitigation payments, major development obligations, or payments to the City of Winnipeg with respect to the 2003 purchase of Winnipeg Hydro, are reflected in the EBIT:Interest or EBITDA:Interest ratios. If not, is this a shortcoming of these ratios?

Rationale for Question:

To explore the limits of these ratios.

Response:

In response to MFR 22, in Tab 9 of the application, Manitoba Hydro provides details on a number of formulas that it employs to calculate financial ratios, including EBITDA:Interest. In that explanation, it is made clear that the starting point for Manitoba Hydro’s calculation is Net Income Attributable to Manitoba Hydro. Net Income is fundamentally an “accrual accounting” concept, and not a “cash flow” concept. As the PUB’s question implies, there are a number of expenditure items which are not captured by “net income”, because they are considered “investment activities” on the Consolidated Statement of Cash Flows. When performing credit analysis on a business, it is customary to carefully consider the actual cash flows of a business, including the full variety of its obligations, and ensure that adjustments are made to any metric that is not fairly representing actual cash flows available for debt service. With respect to the items enumerated above, it is not clear if these obligations rank superior to, equal to or behind lenders, and hence whether the calculation of cash flows available for debt service should take these amounts into account.

At the same time, there are many, many calculations involved in arriving at “Net Income”, including many “non-cash” items, which are normally added back to Net Income in order to calculate cash flows available for debt service. While these are enumerated on

Manitoba Hydro's Consolidated Statement of Cash Flows, the calculated ratios do not appear to fully address these.

Ideally, the details of Manitoba Hydro's financial formulas and metrics would be thoroughly reviewed in order to ensure they are fit-for-purpose in rate-setting. If the purpose of tracking cash flow metrics is to provide comfort to the capital markets that Manitoba Hydro has sufficient ability to service its debts, then the metrics should actually reflect that ability.

However, in the context in which EBIT:Interest and EBITDA:Interest were considered in the MPA Report – i.e., largely focused on the sustained performance of Manitoba Hydro against minimal levels of these metrics over time, driven largely by severe drought risks – the finer details of the calculations may be of lesser importance. Most of the items discussed in this IR are of relatively minor importance in the full scheme of Manitoba Hydro's financial accounts. In severe multi-year drought conditions, Manitoba Hydro's financial performance is likely to overwhelm all of them, even when taken as a group.

PUB/Coalition I-13

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|--------------------------|--------------------|----------------|----|
| Part and Chapter: | CC-15 (MPA Report) | Page #: | 25 |
| Topic: | Drought Impacts | | |
| Subtopic | | | |

Preamble (if any):

At page 25 of its report, MPA states that:

To put these results further into context, the analysis assumed reference values for capital expenditures (derived from the proxy development plan, of course), operating costs, inflation, domestic load, etc. The cases therefore are premised that there will be no active response to an extended series of very challenging drought years (for example, by increasing rates to the maximum allowable 4% per year, or securing alternative energy supply agreements to support domestic supplies, or delaying major capital projects that are in any way optional, or amending or early-terminating unfavourable export contracts, etc.).

[...]

The reality is that there will be intervention if ongoing drought conditions are experienced. As in 2021/22, the PUB would be petitioned, even in the middle of an existing rate-setting period, to raise rates by the 4% maximum amount per year.

In the past four years, there has only been one rate increase above inflation (3.6% during the 2021/22 fiscal years). This was followed by two rate increases of 1.0% annually and a rate freeze during the 2025 calendar year.

In September 2029, 2025, Manitoba Hydro announced a \$63 million loss for the 2024/25 fiscal year.

Question:

In light of the recent experience of the utility not applying for immediate rate relief in a drought despite a net loss, please elaborate on the certainty that Manitoba Hydro would apply for rate relief in the middle of a rate period.

Rationale for Question:

To test the assumption that rate relief is always available as a drought response.

Response:

The government of Manitoba last year announced a one-year rate freeze at Manitoba Hydro, which effectively made it impossible for the utility to request an emergency rate increase during that period. We can only assume that such rate freezes are rare decisions by government, and would therefore not hinder Manitoba Hydro from requesting emergency rate increases in the future, if circumstances otherwise warrant.

Under the existing legislation, Manitoba Hydro can, but is not required to, request rate relief under exceptional circumstances. Manitoba Hydro did do so relatively recently, during 2021/22. The year 2022/23 was not a drought year (in fact streamflows were higher than normal), and while 2023/24 and 2024/25 were both drought years, neither year exhibited conditions as bad for Manitoba Hydro as 2021/22. The fact that Manitoba Hydro did not avail itself of rate relief does not mean that it could or would not do so under more severe conditions.

In considering a new way to approach short-to-medium term rate-setting, one aspect that would potentially provide increased comfort to all stakeholders would be to better define the conditions under which Manitoba Hydro could return to the PUB for rate relief. This would potentially arise naturally out of the scenario testing that could be part of the rate-setting process, as rates would be deliberately constructed to satisfy a range of futures: if reality were to land outside of the planned range, there would be an in-built justification for Manitoba Hydro to return to the PUB for relief.

PUB/Coalition I-14

| | | | |
|--------------------------|--------------------------|----------------|-------|
| Part and Chapter: | CC-13 (Midgard Report) | Page #: | 1, 46 |
| Topic: | Capital Expenditure Plan | | |
| Subtopic: | Asset Management Plan | | |

Preamble (if any):

On page 1 of its evidence, Midgard states:

In short, MH does not appear to believe its AMP outputs, because if it did it would present an AMP that understood and respected its resource constraints and would provide an objective analysis of the spending trade-offs resulting from those constraints.⁵ Instead, MH has presented an AMP that calls for more spending than is proposed in rates, but asks for approval of rates based on BOC investments lower than the AMP recommendation. This disconnected approach to asset management implies that needed operational or risk mitigation projects will not occur, or that the AMP overstates need. Planning to fail is not a prudent way to deliver maximum value to ratepayers.

On page 46 of its evidence, Midgard states:

Despite MH presenting the GRA as if it is based on a robust and objective risk quantification, the AMP clearly identifies gaps, as evidenced by MH's plan to advance its asset management maturity through actions such as improving cost models, updating capital cost estimates, improving inflation forecasts, enhancing risk quantification, linking investments to asset and system outcomes, and integrating the AMP with other groups across MH[.]

Question:

Please itemize and rank the shortcomings in Manitoba Hydro's Asset Management Plan. For each shortcoming, please cross-reference to Midgard's evidence.

Rationale for Question:

To understand the shortcomings in the AMP and whether it supports the proposed capital expenditure plan.

Response:

Table 1 itemizes and ranks the identified shortcomings in Manitoba Hydro's Asset Management Plan.

Table 1: Ranked Shortcomings in Manitoba Hydro's Asset Management Plan with Midgard Evidence References

**Manitoba Hydro Fiscal 2026-2028 General Rate Application
PUB/Coalition Information Requests
October 15, 2025**

| Rank | Shortcoming | Description | Citation ¹⁹ |
|------|---|---|--|
| 1 | Immature Asset Management Practices | <ul style="list-style-type: none"> Does not support consistent and objective prioritization of capital and O&M spending across business lines Uneven asset management maturity advancement: High-level strategy advancing while field-level data, processes and culture lag AMP outputs not believed internally, leading to proposed spending that is disconnected from planning results | Section 1, pp. 9-10 Section 6, p. 37 |
| 2 | Below Competent Maturity Level | <ul style="list-style-type: none"> Overall maturity score (2.33) below ISO 55001 competent threshold (3.0) Progress uneven, with advancements mostly at enterprise/support levels and lagging at operational levels Requires cultural and structural transformation for further advancement to an overall maturity score of 3.0 and beyond | Section 6, p. 37 Section 6.1, pp. 38-45 |
| 3 | Overstated Reliability Degradation Claims | <ul style="list-style-type: none"> System performance stable and superior to peers after accounting for major events; no material performance decline Exaggerates need for aggressive capital investments in asset sustainment to maintain reliability | Section 5, pp. 28-35 |
| 4 | Misinterpretation of Customer Priorities | <ul style="list-style-type: none"> Surveys show limited support for rate increases above inflation Support not demonstrated for MH's proposed 3.5% compounding increases Residential customers satisfied with current system reliability Residential customers prioritize affordability over reliability, and are less satisfied with affordability than reliability | Section 4, pp. 22-27 |
| 5 | Lack of Organizational Integration | <ul style="list-style-type: none"> Operates and plans as separate entities (Generation, Distribution, Transmission, HVDC) rather than a fully integrated utility Impairs consistent, organization-wide risk and value-based decision-making | Section 1, pp. 9-10 |
| 6 | Data Quality and Accessibility Gaps | <ul style="list-style-type: none"> Incomplete, non-standardized, or inaccessible data undermines risk assessment and objective decision-making | Section 6.2, pp. 46-48 |

¹⁹ Exhibit CC-13.

**Manitoba Hydro Fiscal 2026-2028 General Rate Application
PUB/Coalition Information Requests
October 15, 2025**

| Rank | Shortcoming | Description | Citation ¹⁹ |
|------|--|--|--|
| | | <ul style="list-style-type: none"> Relies on subjective judgments rather than data-driven processes Limits ability to accurately and objectively link & prioritize investments to match outcomes and forecast risks | |
| 7 | Optimum Economic Life (“OEL”) Estimation Limitations | <ul style="list-style-type: none"> OEL estimates are biased low, leading to inflated renewal rates and budgets OEL conflated with Average Service Life (“ASL”) OEL Based on inconsistent methods (e.g., expert opinion, industry data) without a foundation on robust MH-specific data Does not consistently consider or account for refurbishment vs. replacement trade-offs, thereby overstating end-of-life needs | Section 6.3-6.3.1, pp. 48-51 |
| 8 | Whole Life Cost Model (“WLC”) Immaturity | <ul style="list-style-type: none"> WLC modelling based upon poor quality OEL data inputs, lack of information systems and data to determine capital maintenance and operating costs, and lack of risk costing Only 20% of targeted WLC models developed to date | Section 6.2, pp. 46-48 Section 6.3.2, pp. 51-54 |
| 9 | Premature Use of Weighted Renewal Rates (“WRR”) | <ul style="list-style-type: none"> Introduced without historical trends or robust OEL data for context setting Risks setting arbitrary targets that justify excessive capital spending without MH-specific self-benchmarking to support meaningful evaluation | Section 6.3.3, p. 56 |
| 10 | Asset-Centric Corporate Value Framework (“CVF”) | <ul style="list-style-type: none"> Asset focus rather than system focus Focuses on individual asset risks rather than system-level risks, thus overstating consequences of individual asset failures to the system and ratepayers Contrary to SAMP principle of system focus, thus leading to misallocated capital | Section 6.3.4, p. 57 |
| 11 | Specific Asset Program Pacing Issues | <ul style="list-style-type: none"> Investments not aligned with actual system needs. Examples include front-loaded spending (e.g., MV Switchgear), uncertain estimates (e.g., HVDC), and asset-focused risks (e.g., Generators) | Section 7, pp. 59-92 |

PUB/Coalition I-15

| | | | |
|--------------------------|---|----------------|----|
| Part and Chapter: | CC-13 (Midgard Report) Appendix 4.3 | Page #: | 20 |
| Topic: | Capital Expenditure Plan | | |
| Subtopic | Policy Alignment and Capital Planning Risks | | |

Preamble (if any):

On page 20 of its evidence, Midgard states:

Accordingly, these shifts in asset orientation and utilization require a recalibration of asset management and capital planning evaluation tools. Risk assessments and asset strategies should change to reflect the anticipated decline in firm export obligations, with incremental risk mitigation investments evaluated and prioritized based on how well they maintain domestic reliability while minimizing domestic rates. Capital planning should also recognize the declining consequences of failure of individual assets whose functionality was previously primarily oriented to support firm exports, which will increasingly become freed up to serve domestic loads, and also that the risk value of opportunistic exports lost due to individual asset failures should be lower than that of firm exports interrupted by similar asset failures. If the consequence of asset failure is reduced, the investment justified to mitigate the associated risk is also reduced. Risk assessments and asset strategies should therefore reflect the lower risks associated with reduced firm export obligations and the commensurately increased share of system capacity freed up to serve domestic loads.

Appendix 4.3 is Manitoba Hydro’s proxy resource development plan.

Question:

Please explain why Midgard considers the consequences of failure to be decreasing for assets that were previously serving firm exports, considering that Manitoba Hydro’s domestic load is growing and will supplant those prior export obligations. Does Midgard consider the generation and transmission assets to be underutilized if dependable energy and peak capacity are transitioned from serving firm exports to domestic loads?

Rationale for Question:

To understand whether the declines in firm export obligations are increasing or decreasing the risk of generation and transmission asset failures.

Response:

Midgard does not consider generation and transmission assets to be underutilized when dependable energy and peak capacity are shifted from serving firm exports to firm domestic loads. Midgard views serving firm domestic and firm export loads as equivalent

from an economic perspective. Generation and transmission assets are considered underutilized only when they are surplus to peak firm domestic and export requirements.²⁰

The risk associated with asset failure is reduced or eliminated when the specified asset is not required to serve firm domestic or export load during a specified period, thereby rendering it surplus (or redundant) during that period. From a system-focused asset management perspective, the consequence of asset failure can therefore change over time.

In contrast, an asset-focused approach treats the consequence of a specific asset failure as constant because it considers only the condition of the asset itself, not its role in the system.²¹ In a system-focused view, risk is determined by the system consequence of failure. If an asset is not currently needed by the system, the consequence and associated risk of that asset failing is reduced or eliminated until the asset is again required. Therefore, a forecast long-term need for an asset that is not presently required does not justify a near-term investment in sustaining that asset (except to prevent catastrophic failure), and such investment should be deferred until the asset is needed.²²

For example, if a single pole of a HVDC Bipole fails and all loads can still be served by other means (e.g., other HVDC Bipoles, alternate AC transmission paths, transmission enhancements such as the R44H Radisson to Henday 230 kV line, imports, or non-wires alternatives such as curtailable load), the asset failure risk is largely reduced or eliminated from a system and ratepayer perspective. The options for mitigating generation and transmission asset failure risk are broader when assessed from a system perspective than from an asset perspective. MH's asset-focused risk assessment limits mitigation options to replacing or rebuilding the specific asset identified as having an unacceptable failure probability. In effect, MH assumes that the only way to mitigate Bipole failure risk is to rebuild or replace the Bipole, even when other system mitigation options exist.

As stated in evidence as it pertains to the HVDC system:

“When queried about the summer and winter peak firm load serving capability MH provided Figure 21 and Figure 22.

...

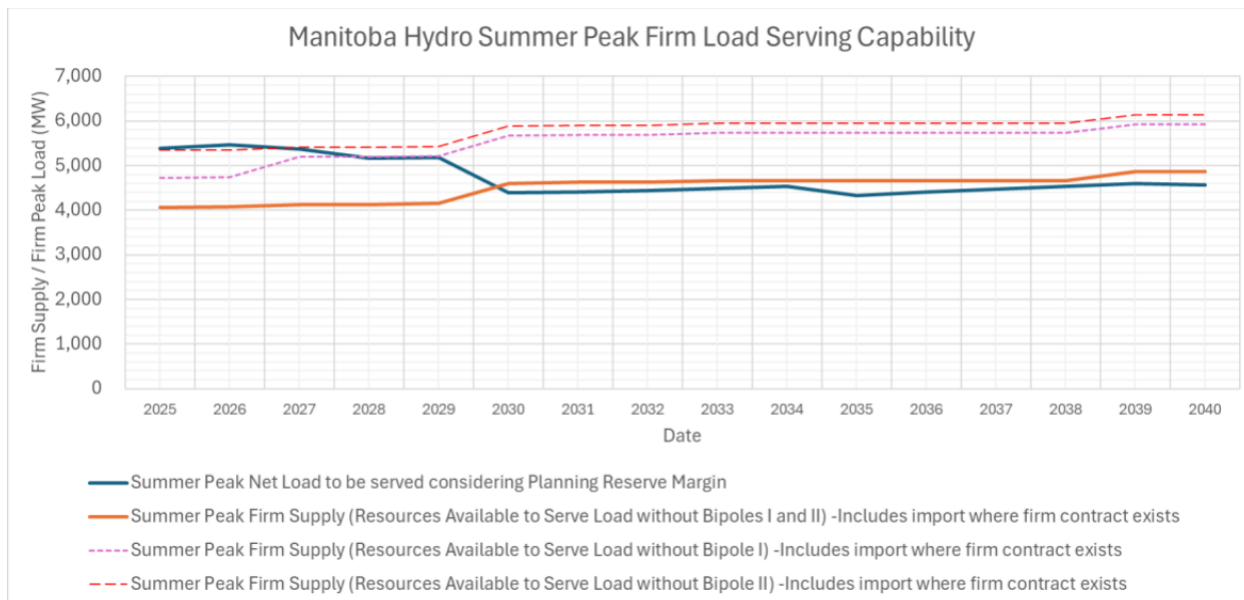
²⁰ Note that electric utility assets are typically underutilized for most hours of the year because adequate system capacity must be available to serve the system peak load hour, while loads during most hours are only a fraction of the peak. This capital underutilization is difficult to avoid given the capital-intensive nature of electric utilities and the challenges associated with increasing system capacity factors by leveling loads. Maintaining redundant critical assets further contributes to apparent underutilization, as such assets are fully utilized only when their counterparts fail. This observation does not indicate Midgard's disagreement with the need for utilities to maintain reasonable redundancy for system-critical assets.

²¹ This discussion excludes routine asset investments required to prevent avoidable catastrophic failures through regular maintenance (e.g., replacing bearing oil to avoid wiping a Babbitt bearing or monitoring transformer oil gases to prevent explosions).

²² Engineering and equipment procurement lead times should be considered when scheduling investments, but they are implementation details, not justification for investment.

Accordingly, Figure 21 shows that in the summer MH has adequate load serving capability throughout the entire 2025 to 2040 period, in particular from 2030 onwards after which firm export obligations decline and MH has sufficient peak firm load serving capacity to manage complete failures of both Bipole I and Bipole II.

Figure 21: Manitoba Hydro Summer Peak Firm Load Serving Capability²³



Similarly, Figure 22 shows that in the winter MH is expected to have adequate load serving capability throughout the entire 2025 to 2040 period with a Bipole failure because failure timings may not coincide with the few hours of peak load and non-firm resources may be available:

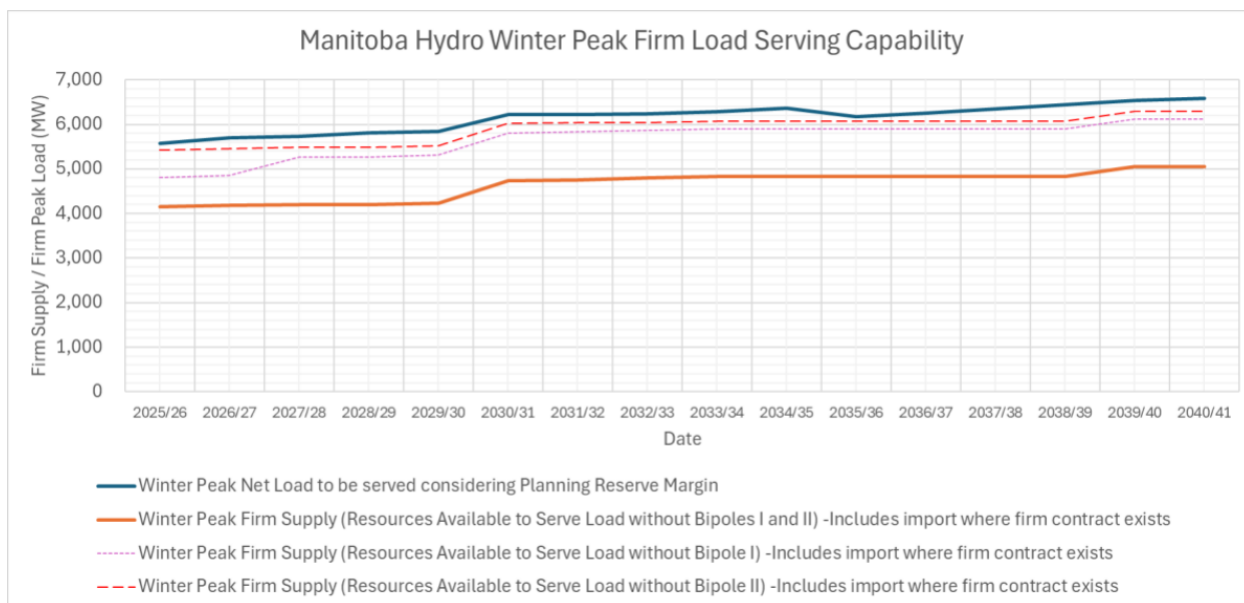
“The shortfalls illustrated above would not necessarily result in load shedding in Manitoba. If firm load is less than expected or if neighbouring systems have excess capacity at the time, firm load may be able to be served.”²⁴

Figure 22: Manitoba Hydro Winter Peak Firm Load Serving Capability²⁵

²³ Manitoba Hydro Response to COALITION/MH I-71(e), p. 6 of 7.

²⁴ Manitoba Hydro Response to COALITION/MH I-71(e), p. 7 of 7.

²⁵ Manitoba Hydro Response to COALITION/MH I-71(e), p. 6 of 7.



In summary, MH has the system capability to serve firm load in the event of Bipole failures because in real time MH can utilize its firm and non-firm contingency resources which are “a combination of Contingency Reserve Sharing deployments, Curtailable Rate Program curtailment, curtailment of Manitoba Hydro’s contracts, curtailment of non-firm energy exports, and/or purchases of non-firm energy in the Day Ahead and Real Time market.”^{26,27}

Midgard does not dispute that asset replacement is eventually required when it is the most effective option to mitigate system risk. However, MH has not demonstrated the urgency of certain proposed generation and transmission replacements (e.g., the HVDC Bipole upgrades) from a system perspective. MH’s evidence indicates that firm domestic and export loads would remain adequately served by the rest of the system if one of these assets failed, at least until domestic load growth offsets surplus capacity freed up by expiring export contracts. Accordingly, Midgard has recommended investment deferrals rather than outright rejection of specific capital projects. This approach recognizes that as domestic load grows over time, the consequence and risk of specific asset failures will commensurately increase over time. The timing of replacements should be based on mitigating unacceptable system risks rather than reducing the failure probabilities of individual assets.

²⁶ Manitoba Hydro Response to COALITION/MH I-71(g), p. 3 of 6.

²⁷ Exhibit CC-13, Section 7.4.1 p. 75, l. 1 to p. 76, l. 8.

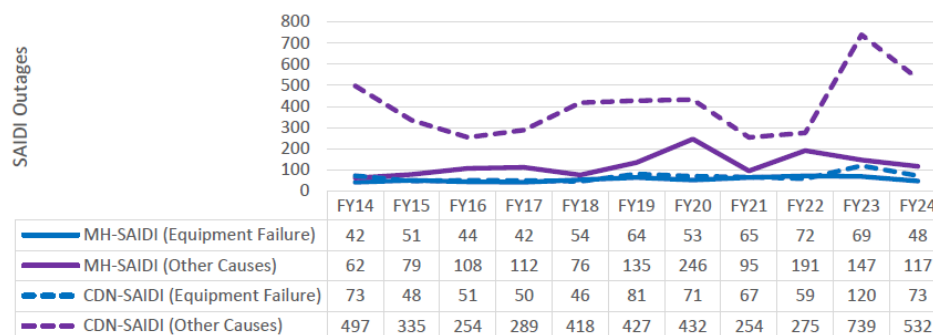
PUB/Coalition I-16

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|--------------------------|------------------------------|----------------|----|
| Part and Chapter: | CC-13 (Midgard Report) | Page #: | 32 |
| Topic: | Capital Expenditure Plan | | |
| Subtopic | Distribution SAIDI and SAIFI | | |

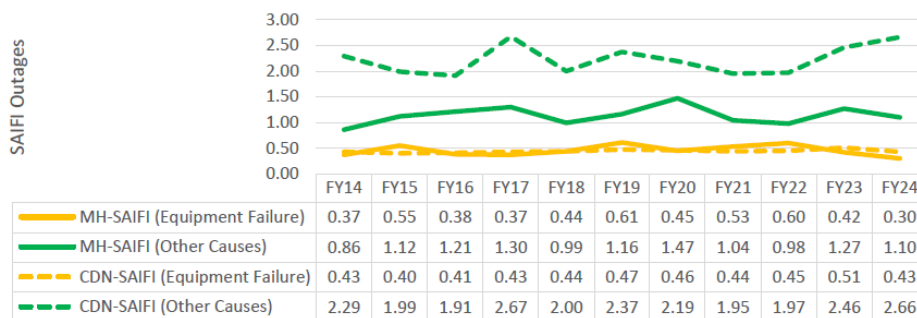
Preamble (if any):

Midgard contrasts SAIDI and SAIFI events caused by equipment failure against events resulting from other causes:

System Average Interruption Duration Index (SAIDI) - Equipment Failure vs. Other Causes



System Average Interruption Frequency Index (SAIFI) - Equipment Failure vs. Other Causes



On page 34 of its evidence, Midgard concludes that:

In summary, MH’s evidence does not demonstrate that distribution system asset condition degradation is materially negatively impacting MH’s reliability performance, so ramping up capital spending to address distribution asset condition should not be expected to produce material improvements in reliability.

Question:

- a) Please explain whether Midgard expects customers to notice a 10% improvement in the Equipment Failure SAIDI and SAIFI scores, within the context of overall SAIDI and SAIFI.

- b) Please estimate the FY24 overall SAIDI and SAIFI if the Equipment Failure SAIDI and SAIFI scores were improved by: i) 10% and ii) 25%.
- c) Please provide Midgard's views as to whether an asset management system that scores above 3 as "mature" would be able to translate a dollar amount of spending into improvements in equipment failure SAIDI or SAIFI. In Midgard's view, is Manitoba Hydro's asset management system capable of doing this?

Rationale for Question:

To understand the magnitude of SAIDI and SAIFI improvements that may arise from increased capital spending to address equipment failures.

Response:

- a) Midgard does not expect residential customers to notice a 10% improvement in Equipment Failure SAIDI and SAIFI scores, because Equipment Failures are a minor contributor to total SAIDI and SAIFI, and the year-to-year variability in the reliability perceived by customers is large relative to such an improvement.

The average Equipment Failure SAIDI and SAIFI for FY14–24 are 55 minutes per year and 0.46 outages per year, respectively. A 10% improvement equates to 5.5 minutes per year and 0.046 outages per year, respectively.

The FY14-FY24 trendline value in FY24 for SAIDI and SAIFI are 232 minutes per year and 1.65 outages per year, respectively. A trendline value was used as a baseline to remove annual variability. The standard deviation between the FY14–FY24 trendline and actual values is 48 minutes per year for SAIDI and 0.184 outages per year for SAIFI.

A 5.5-minute improvement is small relative to a 232-minute average duration and is unlikely to be perceptible given the 48-minute standard deviation. Similarly, a 0.046-outage improvement is minor relative to a 1.65-outage average and is unlikely to be noticed given the 0.184-outage standard deviation. In both cases, the improvements are small compared to normal variability, and accordingly would not be discernible to residential customers.²⁸

- b) If the SAIDI Equipment Failures improved by 10%, the FY24 SAIDI²⁹ would improve from 232 minutes/year to 227 minutes/year.³⁰

If the SAIFI Equipment Failures improved by 10%, the FY24 SAIFI³¹ would improve from 1.65 outages/year to 1.60 outages/year.³⁰

²⁸ For supporting calculations, please refer to Midgard Attachment 1 - Reliability Workbook, Tab "CC-MH I-51a-d", submitted with this deliverable.

²⁹ Based on trendline analysis to remove the effects of year to year variability.

³⁰ For supporting calculations, please refer to Midgard Attachment 1 - Reliability Workbook, Tab "CC-MH I-51a-d", submitted with this deliverable.

³¹ Based on trendline analysis to remove the effects of year to year variability.

If the SAIDI Equipment Failures improved by 25%, the FY24 SAIDI³² would improve from 232 minutes/year to 218 minutes/year.³⁰

If the SAIFI Equipment Failures improved by 25%, the FY24 SAIFI³³ would improve from 1.65 outages/year to 1.54 outages/year.³⁰

- c) Midgard expects a mature asset manager to be able to translate spending levels into estimated improvements in equipment failure-related SAIDI and SAIFI. Midgard does not expect that achieving an overall organizational score of “3” will necessarily have this capability, as that score represents an average across multiple Asset Management Plan (“AMP”) components, some of which may remain below “3”. Areas where MH lags may limit its ability to estimate reliability improvements associated with specific investments, particularly investments intended to mitigate distribution system risks.

As MH continues to improve and increases its organizational score beyond “3”, the ability to link investments to reliability improvements should develop and can be achieved if doing so is prioritized. An overall score of “3” represents achieving a foundational level of maturity rather than completion of the full asset management journey, as the scale extends to “5”. Continued progress beyond “3” would benefit ratepayers, especially as MH operates within an asset sustainment phase where effective asset management is necessary to balance reliability, risk, and cost. As stated in Midgard’s evidence:

“...the revenue requirement and consequently the rates paid by ratepayers, regulatory boards must make trade-offs between ratepayer costs (the proposed ... investments which will affect rates), system performance (the expected service quality and reliability impact of the investments) and risks (the system, safety, environment and economic hazards and opportunities the investments are intended to address). This trade-off concept is illustrated in Figure 11.

³² Based on trendline analysis to remove the effects of year to year variability.

³³ Based on trendline analysis to remove the effects of year to year variability.

Figure 11: Regulatory Trade-off Between Cost, Performance and Risk



³⁴ Exhibit CC-13, Section 6, p. 36, l. 19 to p. 37, l. 2.

PUB/Coalition I-17

| | | | |
|--------------------------|---------------------------|----------------|--------|
| Part and Chapter: | CC-13 (Midgard Report) | Page #: | 58, 65 |
| Topic: | Capital Expenditure Plan | | |
| Subtopic | Corporate Value Framework | | |

Preamble (if any):

On page 58 of its evidence, Midgard states:

Accordingly, Midgard recommends that as MH's asset management maturity improves MH should further transition its CVF implementation from an asset focus to a system focus, because this will better reflect actual system risks and therefore reduce capital misallocation.

On page 65 of its evidence, Midgard states:

Reprioritization of MV switchgear spending, supported by improved outage classification, refined risk thresholds, and updated Corporate Value Framework (“**CVF**”) analysis, is needed to ensure investments align with safety and reliability outcome targets.

Question:

- a) Please confirm whether Midgard sees evidence that Manitoba Hydro uses the CVF to prioritize capital spending, such that capital investments with lower CVF scores are deferred and those with high CVF scores are advanced. Please provide examples that support Midgard's views.

- b) Please provide Midgard's views as to whether the CVF should be used to prioritize capital spending.

Rationale for Question:

To understand whether and how Manitoba Hydro makes use of the CVF.

Response:

- a) Based on the available data, Midgard observes a general trend where projects with higher Corporate Value Framework (“**CVF**”) scores, particularly when normalized by capital cost (CVF per Capital Cost), are scheduled for earlier completion relative to lower-scoring projects. This indicates some prioritization using CVF to advance higher-value investments. However, incomplete data, including missing CVF scores for later-period or deferred projects, prevents a full assessment of whether MH consistently applies this approach across its portfolio or deviations reflect legitimate constraints such as scheduling, resource availability, or interdependencies.

Midgard's review of available CVF scores shows examples consistent with this trend, such as generator overhauls where higher CVF per Capital Cost projects (e.g., Kettle Unit 10 Overhaul at approximately 3.8 versus LS Unit 9 Overhaul at 1.4) are scheduled earlier. Deviations also occur where lower CVF per Capital Cost projects (e.g., Wilkes Station New Feeder W72) are advanced ahead of higher-value alternatives, which may reflect inconsistent CVF prioritization or scheduling related constraints.³⁵

Despite this observed trend, the identified lack of organizational integration and harmonization of asset management practices across business lines persists. As it has done historically MH continues to operate and plan largely as separate Generation, Transmission, and Distribution silos. Consequently, investments are not evaluated consistently across these silos, potentially allowing projects with lower CVF scores in one silo to advance ahead of higher-scoring projects in another silo when viewed at an enterprise level. As stated by MH's expert AMCL+:

*"... modern asset management practices require both structural and cultural changes at utilities to be effective. MH has apparently started to make some of the senior level changes necessary to support development of a modern asset management program, but is lagging at making the operational level improvements and changes that must be implemented for its asset management program to become useful to effectively inform corporate capital investment decisions."*³⁶

MH may argue that resource constraints justify adjusting project timing, asserting that this is acceptable since all projects have positive CVF scores. However, this rationale is flawed. In the Centra Gas Manitoba 2025 General Rate Application, Centra Gas describes its gated approval process, which uses CVF scoring during the Scope Development phase to determine whether projects advance. Projects may proceed if their score is positive or deemed acceptable, even when delays pose minimal quantified risk. For example, regarding its Service Riser Remediation project, Centra Gas stated:

*"While the CVF score and associated cost of delaying the ramp up to 3-years may seem acceptable, in the longer-term, it increases the risk of natural gas leaks due to strained riser piping or corroded below grade entry piping, which Centra finds unacceptable."*³⁷

Treating a positive CVF score as automatic justification for approval undermines the value of CVF as a prioritization tool. A positive CVF does not indicate that the project maximizes potential value or efficiency. The CVF is intended to rank and optimize investments, not simply confirm a minimal level of acceptability. Advancing all positive-score projects removes this optimization function and

³⁵ For supporting calculations, please refer to Midgard Attachment 2 - CAPEX Workbook, Tab "CVF Review", submitted with this deliverable.

³⁶ Midgard Consulting Inc. Evidence filed in Manitoba Hydro 2023/24 & 2024/25 GRA, Exhibit CC-8, Section 7, p. 32. [Link](#).

³⁷ Centra Gas MB Inc. 2025 GRA, Response to CAC-Midgard/Centra II-14, p. 1 of 1. [Link](#).

enables subjective or inefficient capital allocation, particularly across silos where cross-business line comparisons are not performed.

Midgard expects that, since Centra Gas and MH use similar asset management practices, MH likely also advances investments based on having positive CVF scores rather than prioritizing projects to maximize CVF outcomes. This approach overlooks the importance of normalizing CVF by capital cost to account for scale differences, as larger projects may score higher due to size rather than cost-effectiveness in reducing system risk. For example, failing to evaluate alternatives such as project deferral may miss opportunities to achieve higher CVF scores through optimized timing. Similarly, disregarding CVF per Capital Cost reduces the framework's ability to identify projects that deliver greater value per dollar invested.³⁸

- b) CVF is an appropriate tool for prioritizing capital spending once MH addresses identified implementation issues. These issues include Lack of Alternatives/Deferrals, Lack of System Focus, and Risk Valuation Inflation/Misestimation.

Lack of Alternatives/Deferrals occurs when MH advances projects with positive CVF scores rather than maximizing project value through alternative or deferral analysis. Lack of System Focus occurs when MH evaluates risk at the asset level rather than the system level (see Sections 6.3.4 and 7.5 of Midgard's evidence). Risk Valuation Inflation/Misestimation occurs when the consequence or probability of asset failure is overstated. Probability of failure estimation issues related to OEL are discussed in Section 6.3 and its subsections,³⁹ while consequence overestimation is discussed in Sections 6.3.4 and 7.5 of Midgard's evidence.⁴⁰

Examples of potential risk overstatement include Lost Generation Risk, Export Transfer Capacity Risk, and Import Transfer Capacity Risk. In each case, MH assumes full capacity loss upon asset failure without accounting for other system assets that could compensate for the loss. This approach contrasts with MH's improved Safety Risk methodology, which more accurately estimates risk by incorporating both the probability of asset failure and the probability of exposure (e.g., personnel presence at the time of failure):

"This [safety risk] model should be applied in instances where there are no operational restrictions. For example, a substation transformer is deteriorating, and employees are physically present in the vicinity of the

³⁸ This is akin to the investment problem where absolute Net Present Value ("NPV") should be evaluated alongside investment rate of return to see that the investment is both positive NPV and it is efficient at obtaining that positive NPV.

³⁹ Exhibit CC-13, Section 6.3, p. 48 l. 10 to p. 57, l. 12.

⁴⁰ Exhibit CC-13, Section 6.3.4, p. 57 l. 13 to p. 58, l. 27 & Section 7.5, p. 81 l. 1 to p. 89, l. 3.

asset. Their presence is occasional, which reduces the probability of safety risk, but they are still exposed to potential safety risk.”⁴¹

As a final note, CVF is an investment prioritization tool, not a scheduling tool. Resource constraints (e.g., project sequencing or long procurement timelines) and external factors such as permit delays, may affect project scheduling. However, these factors should not materially change prioritization once preferred projects are selected.

⁴¹ Manitoba Hydro Response to COALITION/MH I-56(a-b), Attachment 1: Manitoba Hydro Corporate Value Framework User Guide.

PUB/Coalition I-18

| | | | |
|--------------------------|---|----------------|----|
| Part and Chapter: | CC-13 (Midgard Report) PUB/MH I-64 PUB MFR 35 | Page #: | 70 |
| Topic: | Capital Expenditure Plan | | |
| Subtopic | Risk of Unserved Load Due to HVDC Failures | | |

Preamble (if any):

On page 70 of its evidence, Midgard states:

Although improved automation, diagnostic and vendor support are laudable benefits, by themselves they do not justify nearly \$7B in incremental capital spending. And despite these benefit claims, historical performance data shows that outages on Bipole I and II have not materially affected domestic customers in recent years. As noted previously, there has been no unserved Manitoba Load due to a forced HVDC subsystem outage since 2020/21. Impacts have been managed through contingency reserves, imports, and curtailments of MH's contracts and non-firm energy exports.

On page 2 of the response to PUB/MH I-64 Attachment 1, Manitoba Hydro states:

The loss of Bipole II would bottle about 639 MW firm NCS generation, which is equivalent to the entire capacity of Keeyask GS, or 15% of the total NCS firm generation. Permanent loss of one Bipole I valve group will bottle an additional 140 MW of firm generation from Kettle and Keeyask. Due to the integrated nature of the HVDC system and the NCS generation, the HVDC transmission deficiency arising from the permanent loss of the Bipole II system and a single Bipole I Valve Group can potentially be mitigated in a variety of ways. Direct replacement of the aging assets is the obvious method. However, enhancements to NCS improves the generation plant power output transfer capability between the three Bipoles, allowing better utilization of the HVDC transmission capacity. Life extension of HVDC control systems are also being investigated during scope development.

Manitoba Hydro provided the HVDC and Lower Nelson generation capacities in MFR 35.

Question:

- a) In the event that one of the HVDC poles (i.e. 977 MW for Bipole I or 1000 MW for Bipoles II or III) is down for an extended period of time for maintenance, please confirm whether the risk of unserved load increases in the event of the failure of another valve group or pole to an extent that justifies the investments in upgrading Bipoles I or II.
- b) How should the Manitoba Hydro and the PUB evaluate the value of unserved load in comparison with the cost of upgrading the Bipoles?

Rationale for Question:

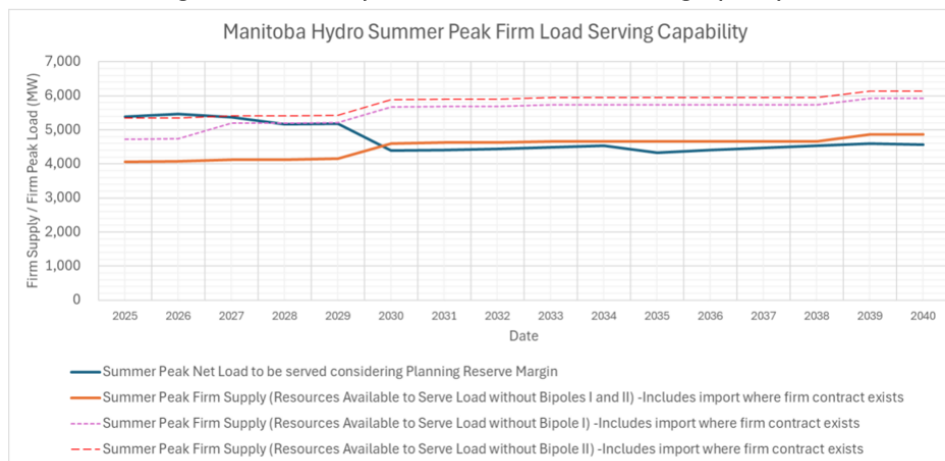
To understand the cost trade-offs between unserved load and investments in the HVDC system.

Response:

- a) If one HVDC Bipole is out for an extended maintenance period, the risk of unserved firm load should not increase. Midgard assumes that MH would schedule maintenance during a low-demand period when failure of another valve group or pole would not result in unserved firm load or could be mitigated through alternate means. If maintenance must occur during the summer peak, evidence shows that MH’s system has sufficient capacity to manage complete failures of both Bipole I and Bipole II from 2030 onward. As Midgard’s evidence states:

“Accordingly, Figure 21 shows that in the summer MH has adequate load serving capability throughout the entire 2025 to 2040 period, in particular from 2030 onwards after which firm export obligations decline and MH has sufficient peak firm load serving capacity to manage complete failures of both Bipole I and Bipole II.

Figure 21: Manitoba Hydro Summer Peak Firm Load Serving Capability¹⁹⁶



” 42

As a result, MH has most of the year to schedule maintenance activities. Exposure to unserved load would only occur during the winter peak if one complete Bipole is taken out for maintenance and another experiences an unexpected complete failure. Midgard does not expect MH to schedule maintenance during the winter peak. As concluded in Midgard’s evidence:

“...MH has the system capability to serve firm load in the event of Bipole failures because in real time MH can utilize its firm and non-firm contingency resources which are “a combination of Contingency Reserve Sharing deployments, Curtailable Rate Program curtailment, curtailment of

⁴² Exhibit CC-13, Section 7.4.1, p. 75, l. 8 to 12.

Manitoba Hydro's contracts, curtailment of non-firm energy exports, and/or purchases of non-firm energy in the Day Ahead and Real Time market". ”
[footnotes omitted]⁴³

It is important to note that once the Bipole I and II neutral electrodes have been rehabilitated (investments which are supported in Midgard's evidence), individual monopole failures can generally be treated as N-1 events, full Bipole failures as N-2 events, and failure of two Bipoles as N-4 events. Few HVDC component failures identified in the evidence should lead to extended failures of the two monopoles comprising either Bipole I or II. Midgard's evidence further supports completing other key capital work necessary to maintain and improve the operational flexibility of the HVDC system, including replacement of HVDC transformers and wall bushings, refurbishment of the neutral electrodes, and completion of the Dorsey-Riel transmission reinforcement.

Most common-mode failure risks posed by Bipoles I and II arise from their southern termination at the same converter station, Dorsey. Most of these risks will remain after upgrades to converter hardware and protections (i.e., such common mode failures are the result of the common converter terminal station for Bipole I & II). Any CVF calculations supporting the scope and timing of Bipole I and II upgrades should evaluate the net system risk reduction achieved by the upgrades relative to the proposed capital spending. Risks that exist before and remain after upgrades should not be counted as CVF value produced by the upgrades.

In summary, the evidence supporting the Bipole I and II upgrades does not justify urgent initiation of either project during the upcoming test period. The risk of being unable to serve all firm loads can be mitigated over the test period and beyond through prudent maintenance planning and the use of internal and external transmission and supply resources. The system has adequate capacity to serve all summer peak load hours following a complete loss of both Bipole I and II (an N-4 event) until 2040.

- b) To evaluate the Value of Lost Load (“VOLL”), the PUB should direct MH to conduct a VOLL study and incorporate the results into its risk assessments such as CVF valuations. VOLL represents a risk to be managed and compared against proposed investments. Midgard recommends that MH continue to mature its asset management processes and apply them, including CVF, to all capital investments. A new evaluation framework is not required, and improvement of existing processes is preferred.

Additionally, for capital investments of the scale of Keeyask or the HVDC Reliability Project,⁴⁴ a separate hearing similar to the 2013–14 “Needs For and Alternatives To” (“NFAT”) proceeding may be appropriate to fully examine alternatives, VOLL, and related risks.

⁴³ Exhibit CC-13, Section 7.4.1, p. 76, l. 4-8.

⁴⁴ Exhibit CC-13, Section 7.4.2, pp. 78-79. MH characterizes the \$6.8B capital cost as an early, high-level Class 10 estimate.

PUB/Coalition I-19

| | | | |
|--------------------------|--|----------------|----|
| Part and Chapter: | CC-13 (Midgard Report) | Page #: | 75 |
| Topic: | Capital Expenditure Plan | | |
| Subtopic | Risk of Unserved Load Due to HVDC Failures | | |

Preamble (if any):

On page 75 of its evidence, Midgard states:

In the event of a Bipole failure, that the 12% Planning Reserve Margin is intended to be available to serve load. Therefore, the Peak Net Load is conservative and overstating the actual load by the amount of the 12% Planning Reserve Margin.

Question:

- a) Please confirm or otherwise explain whether there is a NERC or other limit to how long a utility can rely on its reserve margin to serve load before it must shed load and re-establish the reserve margin.
- b) Please explain Manitoba Hydro's options to respond to a situation where it was using its full reserve margin to serve load and then experienced another generator outage.

Rationale for Question:

To understand Manitoba Hydro's options to address HVDC and generation failures.

Response:

- a) Planning Reserve Margin ("PRM") is a resource adequacy planning framework. The Midcontinent Independent System Operator ("MISO") states:

"...Planning Reserve Margins (PRMs) must be sufficient to cover:

- *Planned maintenance;*
- *Unplanned or forced outages of generating equipment;*
- *Deratings in the capability of Generation resources and Demand Response Resources;*
- *System effects due to reasonably anticipated variations in weather;*
and

- *Variations in customer demands or forecast demand uncertainty.*⁴⁵

As opposed to PRM, Operating reserves enable the utility to maintain adequate reserves in real time to serve the real-time load. Accordingly, MH's operating reserves can be restored in real time (as required by MISO⁴⁶) by calling on:

“...a combination of Contingency Reserve Sharing deployments, Curtailable Rate Program curtailment, curtailment of Manitoba Hydro's contracts, curtailment of non-firm energy exports, and/or purchases of non-firm energy in the Day Ahead and Real Time market.”⁴⁷

Based on the available evidence, MH is planning to carry an adequate PRM over the planning period. Similarly, evidence indicates MH can access sufficient Operating Reserves in real time. Therefore, MH is considered to be using its Operating Reserves appropriately to return the system to a normal condition, in line with NERC Reliability Standard BAL-002, which mandates recovery of the Area Control Error (“ACE”) within a 15-minute Contingency Event Recovery Period following the event and full restoration of contingency reserves within a subsequent 90-minute Contingency Reserve Restoration Period.⁴⁸

- b) Midgard assumes the scenario posed in the question is intended to describe a real-time operating circumstance⁴⁹ in which a major asset failure has fully consumed all operating reserves, which is then followed by another major asset failure prior to restoration of the failed asset or its replacement using any of the various tools available to MH as described in the response to part (a).

First, as stated by MH, it would utilize firm and non-firm contingency resources, which are:

“...a combination of Contingency Reserve Sharing deployments, Curtailable Rate Program curtailment, curtailment of Manitoba Hydro's contracts, curtailment of non-firm energy exports, and/or purchases of non-firm energy in the Day Ahead and Real Time market.”⁵⁰

Next, if these contingency resources were inadequate, it is reasonable to expect that, as has been seen recently in other jurisdictions (for example, in Alberta on January 13, 2025),⁵¹ MH would make a public appeal to its customers to reduce

⁴⁵ Midcontinent Independent System Operator, Business Practice Manual for Resource Adequacy (BPM-011-r11), Section 2, p. 2-11. [Link](#).

⁴⁶ Midwest Independent System Operator, NERC's regional electric system operator for Manitoba and 15 central US states.

⁴⁷ Manitoba Hydro Response to COALITION/MH I-71(g), p. 3 of 6.

⁴⁸ NERC Reliability Guide – Operating Reserve Management Version 3. *Contingency Reserve*, pp. 8-10. [Link](#).

⁴⁹ The failure of multiple independent major assets is not a typical planning scenario used by utilities in resource adequacy assessments to determine an appropriate Planning Reserve Margin.

⁵⁰ Manitoba Hydro Response to COALITION/MH I-71(g), p. 3 of 6.

⁵¹ AESO, *AESO Thanks Albertans for Quick Response to Call for Power Conservation*, January 13, 2024. [Link](#).

domestic load and avoid rolling blackouts. If the public appeal failed to reduce load sufficiently, MH would execute its Remedial Action Schemes and begin rolling blackouts as necessary to reduce firm domestic load and stabilize the MH grid.

Midgard emphasizes that, although a scenario in which multiple independent major assets simultaneously fail during the relatively short annual system peak period⁵² is theoretically possible, utility systems are not typically planned using such extreme scenarios, since planning to make the capital investments necessary to fully insulate the system from such extreme scenarios would impose undue cost burdens on ratepayers to build and maintain assets that would only be needed in rare or extremely low-probability events. Such events are more cost effectively mitigated by taking real time operating actions that are proportionate to and appropriate for the actual circumstances as they unfold in real time.

⁵² Exhibit MH-16, Manitoba Hydro Response to COALITION/MH I-143(a-b), Attachment 2 (Revised), Figure 5.1, p. 28. According to Manitoba Hydro's common bus load duration curve for FY2023/24, the system reached a peak load of 4,307 MW for one hour. Load exceeded 4,300 MW for one hour and 4,000 MW for 55 hours out of 8,760 total hours. Removing the 10 highest-load hours would reduce the effective peak load below 4,300 MW, a reduction of 0.2%. Removing the 50 highest-load hours would reduce it below 4,000 MW, a reduction of 7.1%.

PUB/Coalition I-20

| | | | |
|--------------------------|--------------------------------------|----------------|----|
| Part and Chapter: | CC-13 (Midgard Report) | Page #: | 84 |
| Topic: | Capital Expenditure Plan | | |
| Subtopic | System-Based CVF vs. Asset-Based CVF | | |

Preamble (if any):

On page 84 of its evidence, Midgard recommends evaluating CVF scores on a system basis, not an asset basis:

If the Kettle Units are evaluated as acting as a group, the lost generation risk should not be evaluated in terms of a single unit failing alone, but in terms of the entire generating facility failing to supply required generation. If the entire generation facility is able to supply the required generation and zero (or minimal) actual production is lost by that facility following a single unit outage, the risk posed by that unit alone is reduced. Midgard respects that this type of system thinking will makes the work of capital planners more nuanced, but it will provide a clearer picture of the actual risks posed by a single unit failure on the ability of an entire facility to deliver electricity, and will align with MH's stated strategic asset management objective of focusing on the system rather than the individual asset as discussed previously in Section 6.3.4.

In summary, the linkage between CVF scores and observed asset conditions for generating units is unclear, and CVF appears to be evaluated on an asset rather than system basis, thus creating the potential for overstated risks and misallocated capital.

A generator within a generating station may be redundant most of the time, and thus the generating station can deliver the required output even if one generator fails, but this may not be the case if another generating station with a similarly redundant generator also fails at the same time.

Question:

- a) Please explain how a system-based CVF addresses failures of multiples of the same asset type where the individual assets may, on their own, be fully redundant, but concurrent failures result in insufficient generation.
- b) Please explain how the long lead times for generator repairs affect the system-based evaluation of CVF scores, in the case where a generator fails in a low-load period (early autumn) but the repair to the generator is not completed until after the winter peak period.

Rationale for Question:

To understand how a system-based CVF differs from an asset-based CVF.

Response:

- a) A system-based CVF addresses the failure of multiple assets as follows:

1. The initial state is assumed to be “normal,” with all assets in service and conditions degrading over time (i.e., probability of failure increasing).
2. The group of assets is deemed to require investment when their collective reliability poses an unacceptable risk to serving system demand. The evaluation is performed on the group rather than individual assets.
3. The first asset within the group is identified and planned for replacement or refurbishment, and the group’s overall risk is re-evaluated.
4. The process repeats until the group’s residual risk is reduced to acceptable levels.

For each iteration, additional assets are replaced or refurbished only when the group poses an unacceptable system risk. Replacement continues until the residual units’ risk is reduced to acceptable levels. This approach improves ratepayer value because refurbished or replaced units cover for residual units in poor condition, thus reducing the group’s overall system risk.

This group assessment approach differs from treating all assets as requiring sequential replacement based solely on individual unit capacity, rather than considering the temporal improvement in the group’s collective capacity.

Regarding multiple independent failures and coincidence, treating the assets as a group allows the planner to model the likelihood and consequence of potential independent asset failures within the group while still determining the actual system risk attributable to the group acting together. The likelihood of a single asset failure is higher but of lower consequence than multiple asset failures. Modeling replacement options for an asset group allows planners to compare plans using CVF, such as replacing 1 of N assets, X of N assets, or all N assets. For example, the planner evaluates CVF alternatives based on the probability and consequence (typically low due to redundancy) of N-1 failures, less probable N-2 failures (consequence rising but not linearly, possibly exponential after several coincident unit failures), and so on. The planner then chooses the option that provides the best value to the system and ratepayers.

In practice, GRA filings are likely to present a single project replacing multiple units within a group, rather than a series of independent replacements. For example, the Kettle Unit Overhauls may be paced with rationales for timing to manage group system risks. The number of overhauls (X) required to adequately mitigate risk will be between 1 and 8, but not all eight units must be overhauled, as later replacements produce incrementally less risk reduction than initial unit overhauls.⁵³

- b) Long lead times for generator repairs affect system-based CVF evaluations through their inclusion in risk analysis. The probability that a generator fails during

⁵³ All else being equal. Based on the eight (8) units proposed for replacement in this proceeding.

a low-load period (e.g., early autumn) but is not repaired before the winter peak is evaluated based on the likelihood of occurrence and the consequence for the group's ability to meet winter peak requirements. For example, if seven of eight generators at a plant are required to meet winter peak, the loss of a single generator for a few hours has minimal consequence, and refurbishment is not warranted for risk mitigation. If all eight generators are required, the consequence of failure is high, and investment is likely warranted.

If a generator needed for peak load fails before the peak season and cannot be repaired in time, MH could in most cases purchase monthly or seasonal import blocks or options from external markets to mitigate a potential shortfall during a period of unexpectedly high demand.

In summary, demonstrating that an equipment failure may occur is not sufficient justification for the scope or timing of a major capital investment. Evaluations should consider net system risk, including both probability of occurrence and system consequence, as well as all economically available mitigation options, rather than focusing solely on asset-centric consequences.⁵⁴

⁵⁴ Midgard is not suggesting that asset investments required to avoid catastrophic asset failures should be deferred, although a low-cost mitigation approach for redundant assets that may be subject to catastrophic failure is temporary de-energization until the asset is again needed.

PUB/Coalition I-21

| | | | |
|--------------------------|---|----------------|----|
| Part and Chapter: | CC-13 (Midgard Report) Appendix 4.3 February 25, 2025 Letter to PUB re: Preliminary Estimate | Page #: | 92 |
| Topic: | Capital Expenditure Plan | | |
| Subtopic | Development Costs for New Combustion Turbines | | |

Preamble (if any):

On page 92 of its evidence, Midgard states:

Proceeding with execution funding in the absence of IRP clarity risks premature commitment and reduces flexibility to respond to evolving system conditions. Deferring the Proxy Dispatchable Capacity Resource until approval of MH's next IRP ensures that planning and investment remains aligned with validated system needs. Consequently, Midgard recommends deferring the Proxy Capacity Dispatchable Resource to allow for needs testing in an IRP.

Table 27 presents the consolidated adjusted capital plan for projects related to the Proxy Dispatchable Capacity Resource, comparing the original budget, Midgard's proposed deferral, and resulting adjusted values for FY2026 to FY2035. Midgard recommends retaining limited planning funds of \$0.5M in the current Test Period to allow MH to refine the project scope without overcommitting resources.

On page 4 of its February 25, 2025 Preliminary Estimate for Dispatchable Capacity Resource (link below), Manitoba Hydro stated:

Procurement of long lead equipment requires an early tendering process based on current market conditions. The energy transition is driving intense global demand for new dispatchable capacity resources; suppliers will require deposits in 2025 to meet Manitoba Hydro's anticipated need date of 2029/30. While this cost is incorporated into the preliminary cost estimate, it will impact the timing of cash flows assumed in Manitoba Hydro's financial forecast.

<https://www.pubmanitoba.ca/v1/proceedings-decisions/appl-current/pubs/mh-preliminary-estimates/mh-pub-re-preliminaryestimate-for-dispatchable-capacity-resource.pdf>

Appendix 4.3 shows the in-service date for the new dispatchable capacity resource as 2030/31.

Question:

Assuming the market conditions and the requirement for deposits in 2025 referenced by Manitoba Hydro in its Preliminary Estimate are accurate, please explain how Manitoba Hydro should maintain the timeline for a potential in-service date of 2029/30 or 2030/31

for new combustion turbines if Midgard's recommendation to defer further development of this resource beyond the test period is followed.

Rationale for Question:

To understand Manitoba Hydro's options for protecting an in-service date of 2030/31 while accommodating the need to complete the Integrated Resource Plan.

Response:

Given the magnitude of the proposed Proxy Dispatchable Capacity Resource capital investment, the lack of definition of the required resource (i.e., it is a "Planning Item" not a "Project" in the CAPEX), and the absence of testing resource need or scope in an IRP process, Midgard is concerned that MH has not adequately planned and is not allowing sufficient time for the Board to review its resource requirements and capital plans prior to rates approval.

Moreover, given the "Planning Item" classification, it is unclear that MH can define the technical requirements in sufficient detail to support a tender process or demonstrate that it has optimized the available resource options to constitute a Proxy Dispatchable Capacity Resource.

However, because MH previously failed to forecast the now urgent need for a capacity asset by a potential 2029/30 or 2030/31 in-service date, several bridging options are available to cover the period between a potential in-service date and an actual capacity resource in-service date.

Temporary bridging options based on recent Canadian precedent include, but are not limited to, flexible instruments such as external market import blocks, call options, and rental generation:

1. British Columbia: In its recent Integrated Resource Plan, BC Hydro plans to use temporary market imports to bridge potential resource shortfalls⁵⁵ while managing self-sufficiency legislated constraints and considering ratepayer interests.
2. Yukon: Yukon has historically procured rental generation to meet winter peaking requirements while a more permanent solution to its winter capacity needs is determined.

More permanent options based on Midgard's experience include, but are not limited to:

1. Rate Design: Encourage behavioral modifications to reduce system peaks.
2. Demand Side Management and Energy Efficiency Programs: Modify, accelerate, or introduce programs to reduce system peaks. For example, BC Hydro proposes new

⁵⁵ BCUC Project No. 1599287, BC Hydro 2021 Integrated Resource Plan, Exhibit B-39, Section 2, p. 7, l. 10-11, including Footnote 10. [Link](#).

direct load control, load curtailment, and peak saver incentives to lower peak demand.^{56,57}

3. Non-Wires Alternatives: Shorter lead-time non-wires solutions may be available to reduce system peaks. Example solutions include, but are not limited to, external or utility control of major loads such as hot water tanks, building thermostats, and smart EV chargers, and price signals to incentivize consumer behaviour modification (e.g., rate design or time-of-day pricing).⁵⁸
4. Short Lead-Time Capacity Resources: Utility-scale battery projects may provide peak capacity on shorter development timelines.^{59,60}

Midgard is not proposing that any single suggestion above provides a complete solution to MH's newly identified need. Rather, the measures together can act as a portfolio to address the need until a fully defined and permanent Proxy Dispatchable Capacity Resource solution is identified. Consequently, Midgard continues to recommend that the deposit for a "Planning Item" Proxy Dispatchable Capacity Resource be delayed until after the forthcoming IRP has fully explored the need and available alternatives.

⁵⁶ BCUC Project No. 1599287, BC Hydro 2021 Integrated Resource Plan, Exhibit B-1, Appendix D, Section 5.2.2, p. 21 of 111. [Link](#).

⁵⁷ Some of these programs may also be implemented in conjunction with rate design changes/options.

⁵⁸ Midgard Response to Evidence IR MEED/CC I-1 (c).

⁵⁹ BCUC Project No. 1599287, BC Hydro 2021 Integrated Resource Plan, Exhibit B-39, Section 6, Table 6-1, p. 86. [Link](#). BC Hydro's Signposts update was published in June 2023. BC Hydro estimated that it could achieve 50 MW of additional capacity as early as fiscal 2027, representing an approximate four-year lead time.

⁶⁰ OEB, EB-2024-0115, Exhibit 2 (Part 4), Tab 5, Schedule 8, Section 2.3.2.3, pp. 33-46, [Link](#). Hydro Ottawa's Distribution System Plan identifies four utility-scale BESS projects totaling approximately 25 MW, scheduled for implementation during the 2026-2030 rate period under its Non-Wires Capacity Upgrade program, representing an approximate four-year lead time for four projects.

PUB/Coalition I-22

| | | | |
|--------------------------|--|----------------|-------|
| Part and Chapter: | CC-23 (Rainkie Report) | Page #: | 17-19 |
| Topic: | Enterprise Risk Management & Integrated Strategic Management Framework | | |
| Subtopic: | | | |

Preamble (if any):

Mr. Rainkie states that:

There is no comprehensive strategy to manage key threats to ratepayer affordability of major capital project expenditures, aging infrastructure and the energy transition

Manitoba Hydro's delayed implementation of its Enterprise Risk Management (ERM) Program, including the fundamental components of developing risk tolerance and risk appetite, negatively impacts its ability to understand and assess choices and evaluate risk and cost trade-offs.

The evaluation of a utility's Integrated Strategic Management Framework (ISMF) is an important consideration in the reasonableness and reliability of its financial forecasts and associated rate-proposals.

An ISMF is essential for an organization to determine its areas of focus, make prudent choices that involve trade-offs and achieve synergies between the strategic areas of focus that lead to improved and sustained performance.

The concerns from a rate-setting perspective of the laudable list of operating imperatives contained in "strategic" plans is that they will be unwieldy for the organization and costly for ratepayers as they lack focus, trade-offs and synergistic fit – and in the end will not be successful in providing ratepayer value/affordability and responding to external threats.

[...]

An effective performance measurement system is a critical component of the ISMF. It helps track whether the organization is moving toward its strategic objectives, drives continuous improvement, improves work processes and outcomes, and allows for informed decision-making and corrective action.

Manitoba Hydro's performance measurement system is incomplete and continues to struggle in developing meaningful metrics. This stems, in part, from the lack of a long-term strategy within the ISMF.

Question:

- a) To what extent does the lack of a fully implemented Enterprise Risk Management ERM Program affect Manitoba Hydro's ability to develop a Priority-Based Budgeting (PBB) process and establish rates that reflect prudent cost control and risk management?

- b) How would a fully developed ISMF interact with a three-year PBB process to improve rate-setting decisions and align operational priorities with strategic goals?
- c) How does the ISMF guide the evaluation and justification of placeholder spending for major capital projects, and what improvements are needed to ensure rate proposals are based on reliable cost estimates?
- d) What role does the ISMF's performance measurement system play in demonstrating operational efficiency and justifying the level of rate increases?

Rationale for Question:

To clarify Mr. Rainkie's evidence regarding strategic planning.

Response:

- a) In the absence of a fully functioning ERM Program, MH's decision-making and prioritization of programs and services and associated expenditures is sub optimal.

A fully functioning ERM Program, including the fundamental components of developing risk tolerance and appetite, is essential to MH's ability to (i) understand and assess strategic possibilities and choices, (ii) evaluate risk and cost trade-offs, (iii) analyze the interconnectivity and potential for compounding or offsetting impacts of risks, and (iv) mitigate residual risks of choices and trade-offs made in the decision-making process.

These attributes of a fully functioning MH ERM Program are essential to prioritizing programs and services and related expenditures associated with prudent cost control, priority-based budgeting and ultimately establishing rates that reflect prudently incurred costs. Without a fully functioning ERM Program, MH decision-making and prioritization of programs and services and associated expenditures is sub optimal.

- b) A fully developed MH ISMF is a critical prerequisite to enable priority-based budgeting and align strategic areas of focus and operational priorities. A fully developed ISMF, includes a focused strategy, ERM program and tools, asset management maturity, debt management strategy and performance measurement system, which would allow MH to align its operational plans, activities and projects with its overarching business strategy.

The goal of priority-based budgeting is that available funding is directed to higher value programs and services and scaled back from lower valued programs and services, particularly in times of financial uncertainty or strain. Priority based budgeting shifts from a focus on inputs, spending, expenditure line-items and departments to a focus on programs and services and achieving results and outcomes that are aligned with an organizations strategy and provide value to ratepayers.

A fully developed MH ISMF enables the various steps involved to successfully implement a priority-based budgeting approach as it provides areas of focus, allows for prudent choices that involve trade-offs and to achieve synergistic fit between the areas of focus. Please also see the response to PUB/Coalition I-28 e to h, where Mr. Rainkie outlines the high-level steps that MH would need to take in order to implement a priority-based budgeting approach.

- c) The strategy component of MH's ISMF would be used to determine the utilities aspirations (vision), where to focus to achieve these aspirations, how to provide value to ratepayers in the areas of focus, the required organizational capabilities and enabling management systems. These various aspects of a MH strategy are essential in determining MH's business model on a go-forward basis and how it successfully navigates the triple threats to ratepayer affordability related to major capital project expenditures, aging infrastructure and the energy transition.

MH developing a true strategy (as opposed to an operational imperative plan) and outlining the logic of its chosen business model for both internal staff and stakeholders is an important element in the evaluation and justification of major capital projects, as these major capital projects must be consistent with and enable the chosen strategy and associated business model.

In Mr. Rainkie's view, MH needs to move from "strategic" planning that produces a list of operating imperatives to a true strategy to manage the energy transition. The move from a proxy development plan and placeholder spending to a proposed development plan needs more than an IRP to support it. A true MH strategy should form the foundation of a proposed development plan and be an essential enabling input into the IRP.

The ERM Program and asset management components of the MH ISMF are also important to the evaluation and justification of major capital projects (both development plans and HVDC reliability project) and ensuring that costs estimates are reliable for both business and rate-setting purposes. Evaluating, justifying and developing reliable cost estimates for major capital projects involves understanding and assessing risks, reliability and cost trade-offs in addition to being consistent with MH's chosen strategy and business model.

In Mr. Rainkie's view, MH needs to prioritize maturing its ERM Program and asset management activities as key required organizational capabilities and enabling management systems if it is to successfully move forward into another period of major capital projects. The move from major capital project placeholders to fully developed projects needs to involve mature risk management and asset management capabilities. This is why the delays in implementation and maturation of the MH ERM and asset management programs are both concerning and puzzling.

- d) MH's ISMF performance measurement system should include measures, key performance indicators (KPI's) and associated targets that can be used to

demonstrate operational efficiency and assist in justification of requested rate increases.

MH's performance measurement system and associated measures and targets can demonstrate to the PUB that the utility is designing and implementing the appropriate management actions in order to balance management actions (operational efficiency and cost control) and regulatory action (rate increases).

The MH performance measurement system is also important to assess if the organization is moving towards its strategic directives, to improve work processes and outcomes and allows for informed decision making and taking corrective action as is required. The MH performance measurement system should also serve as a feedback loop for continuous improvement. All of these aspects of a performance measurement system are important to demonstrate operational efficiency and ultimately assist in justification of requested rate increases.

PUB/Coalition I-23

| | | | |
|--------------------------|------------------------|----------------|----|
| Part and Chapter: | CC-23 (Rainkie Report) | Page #: | 23 |
| Topic: | Uncertainty Analysis | | |
| Subtopic: | | | |

Preamble (if any):

Mr. Rainkie states:

MH has no vision on how to further develop the next generation of the Uncertainty Analysis in order to support risk assessment, development of financial targets and ultimately rate-setting.

More advanced forms of risk management programs are able to analyze the interconnectivity and potential for compounding or offsetting effects, of various risks. As such, the Uncertainty Analysis has the potential to be a more powerful risk management tool that can aid in the development of a more advanced ERP Program.

Question:

Does Mr. Rainkie have recommendations for Manitoba Hydro to enhance its Uncertainty Analysis with the use of specific methods, processes or software tools?

Rationale for Question:

To clarify Mr. Rainkie's evidence that the Uncertainty Analysis can be improved.

Response:

Mr. Rainkie's detailed recommendations to enhance the Uncertainty Analysis are outlined on page 24 of his Evidence. The recommended enhancements include:

1. Applying probabilistic thresholds consistent with the PUB direction contained in directive 28 from Order 101/23;
2. Building in both management action (policy changes and cost control by MH) and regulatory action (rate increases by the PUB) into the Uncertainty Analysis;
3. Assessing the residual risk and sufficiency of financial reserves after management actions and regulatory actions are considered in the Uncertainty Analysis; and
4. Developing a minimum retained earnings test (MRET) or similar test to be used for rate-setting.

PUB/Coalition I-24

| | | | |
|--------------------------|------------------------|----------------|-------|
| Part and Chapter: | CC-23 (Rainkie Report) | Page #: | 8, 45 |
| Topic: | O&A Expense | | |
| Subtopic: | Escalation Scenarios | | |

Preamble (if any):

These alternative rate scenarios provided by Mr. Rainkie assume a 2% escalation of O&A and a 10% reduction in forecast BOC spending.

PUB/MH I-61(b) shows that for the years 2014/15 to 2023/24, Manitoba Hydro's O&A expenditures for electric operations have grown at a compound annual growth rate (CAGR) of 3.1% for that ten-year period while there was an acceleration with a CAGR of 8.4% for the years 2019/20 to 2023/24. The forecast now reflects a CAGR from 2024/25 to 2027/28 of 4.7%.

Question:

- a) Explain the basis for assuming 2% annual escalation in O&A in the alternative rate scenarios, including any industry benchmarks or historical MH data supporting these as "more prudent" levels.
- b) Please review PUB/MH I-61 (b) & (c) and provide your comments on the trend and indicate where Manitoba Hydro should target its cost reduction efforts to meet a 2% growth target.

Rationale for Question:

To test Mr. Rainkie's recommendation to cap O&A expenditures at 2%.

Response:

- a) Please see the response to PUB/CAC I-28 a, where Mr. Rainkie outlines the considerations that demonstrate that the alternate rate scenarios with O&A increasing a 2% are reasonable and prudent for rate-setting purposes.
- b) In order to efficiently respond to this information request, Mr. Rainkie has used the combined analysis of the 2020 to 2028 timeframe from Section 5.6. pgs. 64 to 66 of his evidence. This combined analysis contains similar time-periods (2020 to 2028) and trends as the preamble to this information request and response to PUB/MH I-61 b c.

In terms of overall trends, Mr. Rainkie notes that O&A is forecast to increase from \$512 million in 2020 to \$851 million in 2028, an increase of \$339 million or 66.2%. The 66.2% increase in O&A equates to an even annual increase of 6.6% per year.

This 6.6% increase in O&A per year is magnitudes in excess of the increase in Manitoba CPI of 26.0% from 2020 to 2028, which equates to an even annual increase in inflation of 2.9% per year. Clearly, the 6.6% per year rate of increase which is 2.5 times the rate of inflation is not sustainable and does not represent prudent control of O&A costs by MH during this timeframe.

In terms of areas of focus to meet a 2% O&A containment target, Mr. Rainkie's analysis indicates that the most material areas of projected growth, representing 92% of the \$339 million increase are (i) operational employee related increases of \$239 million or 71% of the increase (ii) construction and maintenance increases of \$41 million or 12% of the increase and (iii) consulting and professional cost increases of \$31 million or 9% of the increase. Consistent with this analysis, in Mr. Rainkie's view, these are the most effective expenditure areas for MH to target O&A cost reduction efforts.

Operational employee related costs represent the most material cost category of O&A costs and the most material projected increases in O&A costs. MH should consider an attrition strategy to reduce the number of FTEs consistent with the strategy that was successfully implemented by MH between 2015 and 2017 in order to contain the growth in O&A expenses at 1% per year. Please see the response to PUB/CAC I-28 e to h which outlines high-level steps to use the concepts associated with priority-based budgeting in order to shift the focus from expenditure line-items and departments to outcomes and programs in order to identify areas for FTE reductions and to set top-down targets for employee related cost reductions.

MH should also carefully review construction and maintenance costs, including vegetation management costs and consulting and professional costs to set top-down targets for expense reductions in these expenditure areas.

PUB/Coalition I-25

| | | | |
|--------------------------|---------------------------|----------------|----|
| Part and Chapter: | CC-23 (Rainkie Report) | Page #: | 46 |
| Topic: | O&A Expenditures | | |
| Subtopic: | Impact of Cloud Computing | | |

Preamble (if any):

Graph 6 sets out the increase in O&A expense between the forecast filed in the last GRA and the one filed in the current GRA. This includes projected cloud computing spending

Question:

Please file a revised version of Graph 6 and Table 6 that excludes all cloud computing spending from O&A. If possible, please overlay this assumption onto the existing graph.

Rationale for Question:

To visualize the impact of cloud computing expenditures.

Response:

Please see the revised version of Graph 6 and Table 7 below that exclude all cloud computing arrangement (CCA) expenditures (SAP Core project and small-scale CCA) from the O&A expense comparisons between financial forecasts MH25 (current GRA) and MH22 (last GRA). Please note that it is assumed that the information request is referring to Table 7 from Mr. Rainkie's evidence and not Table 6 as Table 7 contains the data that was used to produce Graph 6.

Mr. Rainkie notes that when all CCA expenditures are excluded from the O&A expense comparisons the total increase in O&A expenses between MH25 and MH22 for the period from 2025 to 2042 remains at \$4.2 billion, consistent with the amount that he used to conclude that the total increase in O&A and BOC expenditures in MH25 of \$5.9 billion is not prudent for rate-setting purposes.

Please also note the following data was used to produce the revised Graph 6 and Table 7:

1. For MH25, small-scale CCA expenses for 2025 of \$14 million (PUB/MH I-3 d, Figure 2) were deducted from the O&A forecast of \$744 million to result in a net O&A of \$730 million. There are no SAP Core project expenditures forecast for 2025 in MH25;
2. For MH22, SAP Core project expenses of \$23 million (MH 2023/24 & 2024/25 GRA, Appendix 4.3, Figure 3, pg. 12) and small-scale CCA expenses of \$9

million (Coalition/MH I-32 f) for 2025 were deducted from the O&A forecast of \$687 million to result in a net O&A of \$655 million;

3. For MH25, the net O&A amounts from 2026 to 2042 were provided by MH in the response to Coalition/MH I-32 f, Figure 2; and
4. For MH22, the net O&A amounts from 2026 to 2042 were calculated based on the SAP Core project amounts provided in the response to Coalition/MH I-32 f, Figure 2 and assuming \$9 million of small-scale CCA expenses per year in accordance with the response to Coalition/MH I-32 f.

Graph 6 Excluding All CCA Expenses from O&A

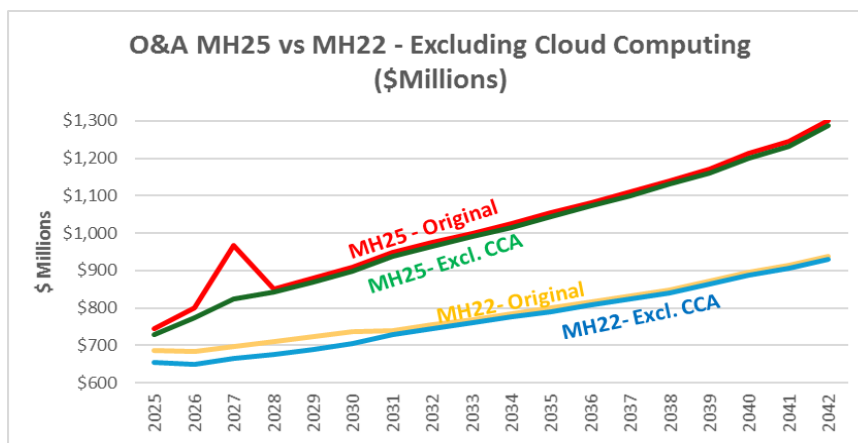


Table 7 Excluding All CCA Expenses from O&A

| O&A and BOC Increases MH25 vs MH22 (\$ Million's) - Excluding All Cloud Computing Arrangements | | | | | | | | | |
|--|---------------|---------------|--------------|------------|---------------|---------------|--------------|------------|--------------|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
| | | | (1 - 2) | | | | (5 - 6) | | (4 + 8) |
| | Annual | Annual | Annual | Cumulative | Annual | Annual | Annual | Cumulative | Total |
| Year | O&A | O&A | O&A | O&A | BOC | BOC | BOC | BOC | Cumulative |
| | MH25 | MH22 | Increase | Increase | MH25 | MH22 | Increase | Increase | Increase |
| 2025 | 730 | 655 | 75 | 75 | 671 | 559 | 112 | 112 | 187 |
| 2026 | 773 | 650 | 123 | 198 | 777 | 617 | 160 | 272 | 470 |
| 2027 | 823 | 664 | 159 | 357 | 791 | 647 | 144 | 416 | 773 |
| 2028 | 842 | 677 | 165 | 522 | 711 | 722 | (11) | 405 | 927 |
| 2029 | 870 | 690 | 180 | 702 | 747 | 750 | (3) | 402 | 1,104 |
| 2030 | 899 | 704 | 195 | 897 | 752 | 788 | (36) | 366 | 1,263 |
| 2031 | 939 | 730 | 209 | 1,106 | 775 | 827 | (52) | 314 | 1,420 |
| 2032 | 964 | 745 | 219 | 1,325 | 895 | 866 | 29 | 343 | 1,668 |
| 2033 | 990 | 760 | 230 | 1,555 | 920 | 905 | 15 | 358 | 1,913 |
| 2034 | 1,016 | 776 | 240 | 1,795 | 964 | 919 | 45 | 403 | 2,198 |
| 2035 | 1,044 | 791 | 253 | 2,048 | 1,021 | 933 | 88 | 491 | 2,539 |
| 2036 | 1,072 | 807 | 265 | 2,313 | 1,041 | 948 | 93 | 584 | 2,897 |
| 2037 | 1,100 | 824 | 276 | 2,589 | 1,085 | 963 | 122 | 706 | 3,295 |
| 2038 | 1,130 | 840 | 290 | 2,879 | 1,136 | 979 | 157 | 863 | 3,742 |
| 2039 | 1,160 | 863 | 297 | 3,176 | 1,189 | 994 | 195 | 1,058 | 4,234 |
| 2040 | 1,201 | 887 | 314 | 3,490 | 1,213 | 1,010 | 203 | 1,261 | 4,751 |
| 2041 | 1,233 | 905 | 328 | 3,818 | 1,237 | 1,027 | 210 | 1,471 | 5,289 |
| 2042 | 1,288 | 930 | 358 | 4,176 | 1,256 | 1,043 | 213 | 1,684 | 5,860 |
| Total 2026 to 2028 | 2,438 | 1,991 | 447 | | 2,279 | 1,986 | 293 | | 740 |
| Total 2026 to 2035 | 9,160 | 7,187 | 1,973 | | 8,353 | 7,974 | 379 | | 2,352 |
| Total 2025 to 2042 | 18,074 | 13,898 | 4,176 | | 17,181 | 15,497 | 1,684 | | 5,860 |
| Total 2026 to 2042 | 17,344 | 13,243 | 4,101 | | 16,510 | 14,938 | 1,572 | | 5,673 |

PUB/Coalition I-26

| | | | |
|--------------------------|------------------------|----------------|-------|
| Part and Chapter: | CC-23 (Rainkie Report) | Page #: | 67-68 |
| Topic: | O&A Expenditures | | |
| Subtopic: | FTEs and Staff Changes | | |

Preamble (if any):

In Table 20 of Mr. Rainkie’s evidence (page 67), it is shown that while Manitoba Hydro claims that a significant portion of the VDP FTE reductions since 2017 have been maintained, if the 2017 Actual Corporate FTE Total is normalized to reduce “Major Capital Project FTEs” of 748, the comparable FTE total for 2017 drops from 6,411 to 5,663.

Comparing this normalized FTE total of 5,663 in 2017 to the 2028 forecast of 5,807 results not in a 604 or 9.4% reduction, but an increase of 144 FTEs or 2.5%. This contention is predicated by the fact that no equivalent FTEs in 2028 are categorized as “Major Capital Project FTEs” as identified with the 2017 normalization.

Manitoba Hydro provides its major capital FTE for 2023/24 in PUB(MH) 1-55 (c) and noted in PUB(MH) II-24 (b) its systems did not allow it to determine what was forecast for major capital in 2028.

Question:

- a) Manitoba Hydro is forecasted to spend \$684 million in Major Capital and Business Operations Capital in 2027/28 (MH Application, Appendix 6.4, Figures 1 and 2). What is the basis for the contention that there are no equivalent “Major Capital Project FTEs” embedded in the 2028 FTE forecast?
- b) Please redo the analysis provide in Table 20 to use 2023/24 as the end year and provide comments on the changes.
- c) Would the FTE costs related to capital and intended to be capitalized in 2028 be considered in part “Major Capital Project FTEs” if their capitalized costs are translated into FTE equivalents?
- d) Please also provide an analysis that excludes all capital projects from 2017 to 2028 and comment on the change in operating FTE numbers.

Rationale for Question:

To further understand the impact of the FTE changes.

Response:

- a) MH was unable to provide information with respect to the FTEs that are engaged on major capital projects during the Test Period. The information from the last MH

GRA with respect to the forecast of major capital project FTEs (PUB/MH I-64 e from the 2023/24 & 202/25 MH GRA) indicated that the total major capital project FTEs forecast for 2025 were 9 FTEs.

As such, Mr. Rainkie assumed that given the early stages of the major capital project placeholders in the current GRA, that the number of major capital project FTEs for the Test Period was not material to the analysis. A small number of major capital project FTEs in the Test Period would not change Mr. Rainkie’s conclusion that Test Period FTEs when normalized for major capital projects have increased since 2017 and not materially decreased as asserted by MH.

- b) Please see the table below that uses 2024 actual FTE figures for the comparison of normalized FTEs between 2017 and 2024. The 2024 actual FTE for major capital projects for 2024 of 27 is sourced from the response to PUB/MH I-55 c.

The truncated time period specified in the information request shows that by the end of 2024, total corporate FTEs normalized for major capital projects decreased by 328 FTEs.

However, Mr. Rainkie notes that total corporate FTEs are projected to increase by 444 FTEs between 2024 and 2028 (5,806 – 5,362 = 444 increase as per MFR 45 pg. 2). When this increase is considered, there appears to be a net FTE increase similar in magnitude to the original analysis, which supports Mr. Rainkie’s conclusion that that Test Period FTEs when normalized for major capital projects have increased since 2017 and not materially decreased as asserted by MH.

Table 20 Comparing Normalized FTEs between 2017 and 2024

| <u>Corporate FTEs Normalized for Major Capital Projects - 2024 Actual vs 2017 Actual</u> | | | | |
|--|----------------|---------------|-------------|----------------|
| | 1 | 2 | 3 | 4 |
| | 2017 Actual | FTE Change | % Change | 2024 Actual |
| Total Corporate FTEs | 6,411 | (1,049) | -16.4% | 5,362 |
| Less: Major Capital Project FTEs | (748) | | | (27) |
| Normalized Corporate FTEs | 5,663 | (328) | -5.8% | 5,335 |

- c) Yes, major capital project FTE costs that are capitalized in 2028 should be part of analysis of normalized FTEs. It is not clear to Mr. Rainkie why MH is not able to provide an estimate of the major capital project FTEs for the Test Period.

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d) Please see the table below that uses the breakdown of business unit FTEs between (i) capital construction, (ii) operations & maintenance, and (iii) governance, support & services from 2017 to 2028 in the response to PUB/MH I-55 d.

This table shows that total business unit operating FTEs (total of operations & maintenance FTEs and governance, support & services FTEs) have increased by 212 FTEs (an increase of 5.1%) between 2017 and 2028.

This analysis also supports Mr. Rainkie’s that MH’s operating FTEs have increased since 2017 and not materially decreased as asserted by MH.

| Business Unit Operating FTEs (Excluding Capital Construction FTEs) - 2017 to 2028 | | | | | | | | | | | | | |
|---|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|--------------|
| | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 |
| | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2028 vs 2017 |
| | Actual | Actual | Actual | Actual | Actual | Actual | Actual | Actual | Forecast | Forecast | Forecast | Forecast | Increase |
| Operations & Maintenance FTEs | 2,643 | 2,472 | 2,329 | 2,389 | 2,208 | 2,314 | 2,501 | 2,609 | 2,780 | 2,793 | 2,852 | 2,852 | 209 |
| Governance, Support & Services FTEs | 1,513 | 1,416 | 1,337 | 1,256 | 1,231 | 1,297 | 1,398 | 1,471 | 1,478 | 1,550 | 1,550 | 1,516 | 3 |
| Total Business Unit Operating FTEs | 4,156 | 3,888 | 3,666 | 3,645 | 3,439 | 3,611 | 3,899 | 4,080 | 4,258 | 4,343 | 4,402 | 4,368 | 212 |
| Annual Change in BU Operating FTEs | | (268) | (222) | (21) | (206) | 172 | 288 | 181 | 178 | 85 | 59 | (34) | |
| Cumulative Change in BU Operating FTEs | | (268) | (490) | (511) | (717) | (545) | (257) | (76) | 102 | 187 | 246 | 212 | |

PUB/Coalition I-27

| | | | |
|--------------------------|------------------------|----------------|----|
| Part and Chapter: | CC-23 (Rainkie Report) | Page #: | 68 |
| Topic: | O&A Expenditures | | |
| Subtopic: | Stretch Targets | | |

Preamble (if any):

Mr. Rainkie describes stretch targets as follows:

Top-Down O&A Stretch Targets: The strategic portion of the O&A budget process that includes stretch targets (\$ and FTEs) and budget guidelines specified by the Executive Committee or Board of Directors that are issued before the bottom-up budget process occurs. These top-down targets consider the focused strategy, the overall financial outlook, revenue requirements and rate pressures for many years into the future

Question:

- a) Please discuss Mr. Rainkie’s understanding of prior stretch targets utilized by Manitoba Hydro in its rate setting context.
- b) Does Mr. Rainkie have any specific recommendations for the stretch targets that Manitoba Hydro should consider with respect to O&A levels and staffing FTE levels.
- c) Please indicate what would be considered achievable and how the targets would impact the revenue requirement for 2026/27 and 2027/28.

Rationale for Question:

To further explore Mr. Rainkie’s recommendation regarding top-down stretch targets.

Response:

- a) For many years prior to 2015, MH’s top-down O&A budgeting target was generally to maintain O&A cost increases at 2% per year consistent with levels of expected inflation, excluding accounting changes that impact O&A.

For the 2015 to 2017, MH’s top-down O&A budget target was to maintain O&A cost increases at 1% per year, excluding accounting changes that impact O&A. In order to meet this stretch target, MH committed to reducing approximately 330 operational positions over that time frame.

Response to Questions b) and c):

Please see the response to PUB/Coalition I-28 a, where Mr. Rainkie outlines the considerations that support his view that the 2% escalation in O&A from 2026 and onward the are included in the alternative rate scenarios that were used to provide his 2.25% rate

recommendation for the Test Years represent appropriate and prudent levels of O&A for rate-setting purposes as part of this regulatory proceeding.

The impact on the 2027 and 2028 revenue requirement of O&A escalation at 2% would be to reduce O&A in 2027 from \$968 million to \$911 million or a decrease of \$57 million and to reduce O&A in 2028 from \$851 million to \$789 million or a decrease of \$62 million.

PUB/Coalition I-28

| | | | |
|--------------------------|--|----------------|-------|
| Part and Chapter: | CC-23 (Rainkie Report) | Page #: | 69-70 |
| Topic: | Priority Based Budgeting (PBB) & Forecast O&A Expenses | | |
| Subtopic: | | | |

Preamble (if any):

Mr. Rainkie states:

From the review of the 2020 to 2028 O&A information, the MH O&A budget process appears to be mainly a bottom-up and incremental budget approach – with an ineffective top-down stretch target and alignment process. Incremental budget approaches (also known as a line-item budgeting approach) are backwards looking where previous years budgets are the foundation for the next year and the primary focus is on expenditure category inputs. Under this approach there is no demonstrated relationship between spending and program outcomes.

MH's O&A targets are set on an incremental basis by starting with last year's actual O&A as a base and then adjusting upward for (i) general wage increases, (ii) merit and progression increases, (iii) operating imperatives, and (iv) other inflationary cost pressures.

The net impact of MH's O&A budget process is to follow the cost curve on its upward trajectory and represents passive management of O&A costs, at best.

Mr. Rainkie recommends that MH utilize a Priority Based Budget (PBB) process in establishing the O&A expense. On that basis Mr. Rainkie recommends a 2% annual increase in O&A expense.

Question:

- a) What timeframe do you believe will need to be followed to implement each of the recommended changes to the budgeting process proposed to adopt PBB, and how would it inform this rate application?
- b) Please indicate whether, to Mr. Rainkie's knowledge, Manitoba Hydro had considered or studied the use of PBB.
- c) Please explain how MH's forecast O&A spending would be expected to change utilizing a PBB approach for the 2026 to 2028 period and whether Mr. Rainkie considers his revised forecast of O&A expense to be achievable on this basis.
- d) Please indicate where PBB has been incorporated for a utility on a rate-setting forecast basis.
- e) Please describe the steps Manitoba Hydro would need to take to implement PBB, and the approximate timeline required.

- f) What are the potential costs of implementing PBB (e.g., training, system upgrades, consulting)?
- g) Would an adoption of PBB be consistent with changes that could be made with the adoption of functionality within SAP S/4HANA?
- h) Describe how Manitoba Hydro prioritize programs and services under PBB, and what criteria would be used in establishing budgets?

Rationale for Question:

To test Mr. Rainkie's evidence on priority-based budgeting.

Response:

- a) In Mr. Rainkie's view, the issue before the PUB for rate-setting purposes is the prudent level of O&A costs to include in rates. The PUB does not typically explicitly approve the levels of O&A or disallow specific O&A costs as part of the approval of MH rates. Rather, consistent with its rate-setting role, the PUB typically approves levels of overall general revenues by implicitly considering revenue requirements and levels of O&A costs that are necessary and prudent.

From the last paragraph of the preamble, the premise of this question appears to be that Mr. Rainkie recommends a 2% increase in O&A costs as a revised forecast that is contingent on MH implementing a priority-based budgeting (PBB) approach during the 2026 to 2028 Test Period.

To clarify, Mr. Rainkie is recommending 2.25% rate increases for each year of the Test Period by placing emphasis on the medium-term forecasts to 2035 and considering alternative rate-setting scenarios that include more prudent levels of O&A and BOC costs than that which are forecast by MH in its long-term financial forecast. Mr. Rainkie has not made his own detailed forecast O&A based on the assumption that MH will implement PBB in the Test Period as the premise of the question appears to suggest.

To further clarify, Mr. Rainkie's recommendation for even annual 2.5% rate increases in each of the Test Years is based on the alternative rate-setting scenarios to 2035 and is not dependent on MH achieving the indicated levels of O&A cost control specifically in the short-term of Test Period. There is time in the medium term for MH to course correct and address more appropriate fiscal restraint and O&A cost control. In Mr. Rainkie's opinion, if sole-emphasis is placed on the test year forecasts (including MH forecast of costs without the more prudent cost control) then 3.5% rate increases are not justified and rate increases in the range of 1.0% to 1.5% in each Test Year would be indicated (Please see Section 6.5, pgs. 79 to 81 of Mr. Rainkie's evidence).

In Mr. Rainkie's view, the \$5.9 billion increase in O&A and BOC in the long-term forecast since the last MH GRA is not prudent for rate-setting purposes,

considering the negative financial impacts of the higher and earlier major capital project placeholders. The prudent course of action would have been for MH to significantly reduce the growth in its day to day controllable costs (O&A and BOC) in its updated financial forecast to lessen the rate pressures as a result of the increases in major capital project placeholders and to more appropriately balance management action (MH cost control) with regulatory action (PUB rate increases). Unfortunately, MH has failed to make these prudent choices and chose to move forward with proposed rate increases that include this combined \$5.9 billion increase in forecast O&A and BOC expenditures, resulting in the 3.5% proposed long-term rate path.

The alternative rate scenarios upon which Mr. Rainkie basis his recommended rate increases of 2.25% were designed to illustrate plausible alternative rate paths that include more prudent cost control than that planned by MH in its updated financial forecast, while at the same time reflecting appropriate escalation. These alternative rate scenarios assumed 2% escalation in O&A from 2026 and onwards excluding SAP Core project costs that are proposed to be deferred and amortized and a 10% reduction in forecast BOC spending.

In Mr. Rainkie's view, the alternative rate scenarios include appropriate and prudent levels of O&A in the medium term, for rate-setting purposes, based on the following considerations:

1. MH's O&A costs have already escalated by 45% between 2020 and 2025, which is an even annual increase of 7.8% per year or 2.3% times the even annual rate of Manitoba CPI of 3.4% per year;
2. Continued escalation of MH's O&A costs at levels that are double the level of Manitoba CPI are not sustainable; and
3. Escalation of 2% per year in 2026 and thereafter based on the higher O&A costs levels forecast for 2025 is still significantly higher than the levels of O&A forecast by MH at the last GRA. The 2% O&A escalation is not a reduction of O&A costs but rather a reduction in the rate of growth of O&A in the future;
4. Escalation of 2% per year in 2026 and thereafter is consistent with the projected level of Manitoba CPI and is a reasonable stretch target for MH based on past practice and the expectation that regulated public utilities control costs and run efficient operations. MH's own long-term planning assumption with respect to O&A cost escalation at the last GRA was 2% after the test years;
5. MH's long-term forecast approach tends to include placeholders for spending but no expectation or offsets for benefits and cost reductions result from this spending. MH is forecasting significant digital and technology expenditures (SAP Core project, small-scale CCA's and AMI as examples) but has not included any benefits or associated cost reductions in its financial forecast. Further, artificial intelligence (AI) is being described as the "Fourth Industrial

revolution” and is expected to significantly transform work, improving productivity across all industries and automating work tasks. There is no consideration of this transformation in MH’s 20-year long-term financial forecast; and

6. MH is projecting to enter into another period of major capital spending that will place significant pressure on its financial outlook and indicative rate increases. In these circumstances, prudence would dictate a more disciplined approach to O&A cost control than has been demonstrated by MH from 2020 to 2025.
- b) In Mr. Rainkie’s experience, MH has not considered or studied the use of PBB.
 - c) Please see the response to part (a) of this information request.
 - d) In Mr. Rainkie’s experience, utilities generally use the traditional incremental O&A budgeting approach for business and rate-setting purposes. He has not come across a utility that uses a non-traditional approach to budgeting such as PBB for business or rate-setting purposes.

However, in this time of financial uncertainty and strain, it would appear to Mr. Rainkie that utilities could benefit from the use of PBB and that PBB would be of assistance for both business purposes and rate-setting purposes. This is particularly the case for natural monopolies and public sector organizations where there are no inherent competitive pressures to promote cost control. The rate-setting process is designed to simulate a competitive environment by considering prudent levels of O&A to include in approved rates.

Response to Questions e) to h):

As part of the process of evaluating MH’s O&A cost control, Mr. Rainkie outlines his views with respect to leading O&A budgeting practices for regulated utilities, including a focused strategy, multi-year O&A budgeting, top-down stretch targets, bottom-up budgeting, alignment of top-down targets and bottom-up budgets, measurement of actual performance as well as taking corrective action and on-going reinforcement.

Mr. Rainkie then goes on to observe that these leading O&A budget practices are consistent with a priority-based budgeting (PBB) approach and that MH would benefit from such an approach.

In Mr. Rainkie’s view, MH has options to improve its O&A budgeting approach including adopting the above noted leading practices through an effective top-down, bottom-up and alignment process or adopting a non-traditional budgeting approach such as PBB. A leading practise approach (top-down, bottom-up and alignment process) could be adopted for the next budgeting cycle. Moving to a non-traditional budgeting approach such as a PBB, would likely require a second budgeting cycle to implement and require sustained effort by MH.

A PBB approach (also known as outcomes-based budgeting) is a strategic approach to O&A allocation and represents a significant shift from traditional budgeting methods.

The shift is from a focus on inputs, spending, expenditure line-items and departments - to a focus on programs and services, achieving results and outcomes that are aligned with corporate strategy and provide value to customers. As part of PBB, funding is directed to higher-value programs and services and scaled back for lower value ones during times of financial uncertainty or strain. The focus shifts from the level of O&A expenditures from the last year plus incremental escalation - to a focus on how the most value can be created for customers using the O&A funding that is available on a go-forward basis.

Specifically, MH must also shift from its current mindset that O&A costs are beyond its control to a mindset that it can control and influence its O&A costs through focus, choices and trade-offs and generating alternative possibilities and associated strategies to control growth in O&A costs.

At a high-level, the steps that MH would need to take in order to implement a PBB approach would include:

1. Identifying the level of O&A expenditures that are reasonably available on a top-down basis considering MH's overall financial outlook and indicated rate increases in order to establish a limit on how much can be budgeted for O&A for the upcoming fiscal year(s);
2. Identifying priorities of the organization based on a focused strategy and associated strategic priorities that are expressed in terms of outcomes or results that are of value to MH's customers;
3. Identify the various programs or sets of activities that MH uses to provide the desired customer outcomes or results as well as the cost of these MH programs. A program view of costs for electric operations would need to be developed by MH in order to implement PBB;
4. Develop a process to evaluate/score how the programs achieve or influence the desired customer outcomes or results such that each program has a score that indicates its relevance to the priorities;
5. Compare scores between programs to develop a top to bottom comparison/ranking of the prioritized programs;
6. The available O&A funding is allocated to the prioritized programs to align resource allocation consistent with the results of the priority-driven scoring. There are a number of methods to carry out this allocation that need to be tailored to the organization. Programs can be ordered according to their prioritization within a priority result area and a line can be drawn by senior management considering available O&A resources with programs above the line being funded and the ones below the line not being funded. Alternatively, programs can be organized into tiers

of priority and reductions can be allocated by tier with programs in the top tier not being reduced and programs in the lowest tier being allocated the highest reduction; and

7. Accountability for deliver of results has to be created to ensure that programs deliver the results that they were evaluated on, including establishing performance measures to determine if the desired results are being provided and take corrective action as necessary.

As noted above, Mr. Rainkie has suggested in his evidence that MH would benefit from a PBB approach on a conceptual basis but has not been engaged to develop a detailed implementation plan and associated costs estimates as part of the scope of his engagement. There is limited information on the record of this proceeding with respect to SAP S/4HANA functionality. Mr. Rainkie's basic understanding is that SAP S/4HANA can support PBB. However, this would need to be confirmed with MH in terms of the functionality that it plans to implement as part of its SAP Core project.

PUB/Coalition I-29

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|--------------------------|------------------------------------|----------------|---------|
| Part and Chapter: | CC-23 (Rainkie Report) | Page #: | 80, 102 |
| Topic: | Financial Health of Manitoba Hydro | | |
| Subtopic: | Financial Benchmark Metrics | | |

Preamble (if any):

Table 22 on page 80 shows that, while the net income varies significantly with changes in the rate increase percent, all other financial metrics vary minimally, by very small fractions (Retained Earnings, Net Debt, Equity Ratio, EBITDA Interest Coverage Ratio, Capital Coverage Ratio).

In particular, a 1% increase for 2026 yields a capital coverage ratio (at 1.04), that is identical to the capital coverage ratio with a 1.5% increase.

In table 30 on page 102, Mr. Rainkie presents his recommended rate increase, along with the resultant financial metrics.

Question:

- a) Given the narrow results seen with the changes in rate increase percents seen in Table 22, and contrasting these results with Table 30, please provide a detailed explanation of the meaningfulness of each financial metric for Manitoba Hydro as a benchmark for evaluation.
- b) Are there specific minimum or maximum thresholds for financial metrics to target with the preferred rate increase?
- c) Should any of these targets take precedence over other listed financial metric targets in pursuing the financial health of Manitoba Hydro?
- d) Does Mr. Rainkie recommend any other financial metrics and associated targets, that should be addressed by Manitoba Hydro to pursue financial health?

Rationale for Question:

To test Mr. Rainkie's evidence on financial metrics.

Response:

- a) In Mr. Rainkie's view, the narrow results of the various financial metrics in Table 22 of his evidence for the Test Period do not demonstrate the lack of meaningfulness of the financial metrics, but rather are attributed to the fact that MH has requested that each of the three proposed rate increases be made effective at the start of the 4th quarter in each of the Test Years (January 1 of each

year). As a result, the annualized impact of the various rate scenarios in Table 22 are not readily apparent in the 3-year Test Period.

As the period of analysis is extended to the 5-year period from 2026 to 2030 (Table 28, pg. 97 of Mr. Rainkie's evidence) and the 10-year period from 2026 to 2035 (Table 29, pg. 99 of Mr. Rainkie's evidence), the impact of various rate increase scenarios on the financial metrics will become much more significant if the same level of costs are assumed in each rate scenario.

Tables 28, 29 and 30 of Mr. Rainkie's evidence compares the financial metrics between MH25 with MH's cost forecasts and Consumers Coalition alternative rate scenarios CC6, CC7 and CC8 which all contain more prudent levels of cost control related to O&A and BOC.

The fact that the financial metrics of MH25 and CC6 to CC8 are within a reasonable range in these tables does not demonstrate the lack of meaningfulness of the financial metrics, but rather is attributed to the fact that more prudent cost control by MH is a powerful lever to reduce the required rate increases and achieve financial results that are similar to that which is desired by MH.

The traditional financial metrics (net income, retained earnings, net debt, equity ratio, EBITDA interest coverage ratio and capital coverage ratio) that have been used by the PUB to set electricity rates in the past, incorporate elements of the three primary financial statements. Equity, retained earnings and debt from the statement of financial position, net income and EBITDA from the statement of income and cash flow from operations from the statement of cash flows. Levels of retained earnings can be assessed against the impacts of significant risks to MH such as the impacts of a major drought and levels of net debt can be assessed to determine if MH is generating sufficient cash flow to fund sustaining capital expenditures over time (major capital projects are usually financed with debt).

Taken as a whole, these traditional financial metrics provide a robust picture of MH's financial health, for rate-setting purposes. The use of these traditional financial metrics also (i) allow for flexibility in setting rates to achieve rate-stability and predictability for ratepayers, and (ii) reduce the risk of over reliance on only one metric to set rates (such as return on rate base that is commonly used to set rates for investor owned utilities).

- b) It is assumed that the reference to "the preferred rate increase" in the information request means Mr. Rainkie's recommendation of 2.25% rate increases for each of the Test Years.

In conducting his analysis and making this recommendation, Mr. Rainkie has relied on

1. The analytical framework used by the PUB to set rates in the last MH GRA, including consideration of all three of MH's prior financial targets and comparison of retained earnings and the impact of a 7-year drought; and

2. The prior targets that have been traditionally used by MH related to Equity Ratio, EBITDA Interest Coverage and Capital Coverage as well as the practice of gradual movement towards these targets as opposed to ridged adherence to the prior targets.

Pending the completion of MH's financial target review and subsequent public review at the next MH GRA, Mr. Rainkie does not see the value in proposing interim targets for the various financial metrics, for rate-setting purposes.

- c) As noted in the response to PUB/Coalition I-29 a, the traditional financial metrics used by the PUB for rate-setting, when take as a whole, provide a robust picture of MH's financial health, allow for flexibility to achieve rate stability and predictability and reduce the risk of over reliance on one metric to set rates. As such, Mr. Rainkie recommends that the PUB continue to use all of these metrics on a holistic basis to set rates in the 2026 to 2028 Test Period and that one of these metrics/targets should not take precedence over the others.
- d) As outlined in the response to PUB/Coalition I-23, Mr. Rainkie recommends that the Uncertainty Analysis be enhanced and used to develop a minimum retained earnings target (MRET) for MH.

PUB/Coalition I-30

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|--------------------------|-------------------------|----------------|-------------|
| Part and Chapter: | CC-23 (Rainkie Report) | Page #: | 78, 102-103 |
| Topic: | Overall Recommendations | | |
| Subtopic: | Fairness to Ratepayers | | |

Preamble (if any):

Mr. Rainkie on page 78 identifies a number of concerns with respect to Manitoba Hydro's cost estimates:

Sections 3.0, 4.0 and 5.0 of this Evidence have raised a number of concerns with respect to uncertainty, reliability of significant placeholder spending and prudence of cost estimates.

In Section 3.0 of this Evidence, it was concluded that many aspects of the MH ISMF are incomplete which negatively impacts its ability to determine areas of strategic focus, make prudent trade-offs and achieve strategic synergies. The areas that support this conclusion are:

- (1) MH has no comprehensive strategy to manage key threats to ratepayer affordability of major capital project expenditures, aging infrastructure and the energy transition;
- (2) The implementation of MH's ERM Program has been significantly delayed and risk tolerances and appetite have yet to be developed;
- (3) MH has no vision on how to further develop the Uncertainty Analysis to improve risk management and for rate-setting purposes;
- (4) MH does not plan to achieve asset management competence until 2032 which puts in question its commitment to prioritize BOC spending;
- (5) MH's Debt Management Strategy is in a holding pattern pending an external review and appears to be still relatively risk-averse to using higher levels of variable-rate debt;
- (6) There are substantial capital project placeholders (\$11.7 billion) in MH25 in early stages of development that lack investment justifications; and
- (7) MH's performance measurement system continues to be a work in progress.

Mr. Rainkie also notes in summary on page 103:

The 2.25% rate recommendation assists the PUB its mandate to balance the impact on ratepayers with the financial health of MH. The cumulative rate increase is used as metric in this Evidence to represent the impact to ratepayers. The financial health of MH is represented by the financial metrics described above.

Question:

- a) In consideration of the purported lack to MH planning functions and tools noted in the item (1) above, how likely does Mr. Rainkie consider it to be that costs will significantly increase during the rate period or future periods beyond what is currently projected?
- b) If such an increase were to materialize and rates are set at 2.25%, please comment on the potential for rate shock in future applications or financial problems to Manitoba Hydro caused by the 4.0% rate cap. How should the Board weigh this risk against the benefit of lower rate increases for the current rate period?

Response:

- c) Mr. Rainkie notes the concerning trend of substantial increases in MH controllable costs (O&A and BOC) on a forecast over forecast basis since the MH 2018/19 GRA (combined increase of \$2.3 billion in the last GRA and \$5.9 billion in the current GRA).

In the absence of (i) improvements in the MH Integrated Strategic Management Framework to address the deficiencies that are outlined in Mr. Rainkie's evidence (and the preamble to this information request) and (ii) regulatory signaling by the PUB through the level of costs that it allows in rates and findings with respect to the prudence of O&A and BOC – it is quite likely that this trend will continue and cost forecasts will escalate beyond that which is currently projected.

- d) Mr. Rainkie is of the view that awarding higher than required rate increases in order to mitigate the risk of higher MH costs at future GRAs is not consistent with the PUB's rate-setting role and mandate and would have the opposite effect of contributing to the risk of of MH costs increasing beyond that which is currently projected in this GRA.

Mr. Rainkie notes that using the MH projected costs and assuming 2.5% rate increases from 2026 to 2028, MH projects indicative rate increases of 3.78% from 2029 to 2045 to achieve a 21% equity ratio by 2045 (Please see the response to Coalition/MH II-82 d). Mr. Rainkie also notes that using the MH projected costs, the Uncertainty Analysis indicates indicative rate increases of 4.3% at the upper quartile (P75).

From a quantitative perspective, using the above noted rate scenario and Uncertainty Analysis as indicators, there is potential for rate volatility/indicative rate increases in excess of 4.0% or weak financial results if the past trend of significant forecast over forecast increases in MH's controllable costs persists and is not suitably addressed by MH management action and PUB regulatory signaling.

In contrast, at the more prudent levels of costs included in the Consumers Coalition rate scenarios, and assuming 2.5% rate increases from 2026 to 2028, MH projects indicative rate increases of 2.83% to achieve a 20% equity ratio by 2045 (Please see the response to Coalition/MH I-27 (Updated, Figure 10). Both Mr. Rainkie (evidence pgs. 90 to 91) and Mr. Bowman (evidence pgs. 26 to 27) are of the similar view that the more prudent level of costs included in the Consumers Coalition rate scenarios would serve to reduce the 4.3% upper quartile (P75) indicative rate increase in the Uncertainty Analysis to 3.3%.

Clearly, from a quantitative perspective, using these indicators, the best approach to mitigate the risk of rate volatility/indicative rate increases in excess of 4.0% or weak MH financial results is more prudent cost control by MH and appropriate regulatory signaling by the PUB with respect to the prudence of forecast costs.

From a policy perspective, the PUB awarding higher than required rate increases in the Test Period to mitigate the potential of future rate volatility/indicative rate increases in excess of 4.0% or poor MH financial results as a result of the risk of MH not prudently controlling its costs in the future is not consistent with (i) the PUB rate-setting role of setting rates based on prudently incurred costs, and (ii) the PUB mandate of balancing the interests of ratepayers with the financial health of MH.

In addition, such an approach would not be effective in mitigating this risk and could represent an element of moral hazard. In Mr. Rainkie's view, awarding higher than required rate increases would signal/reinforce to MH that its current approach to cost control and ever increasing costs on a forecast over forecast basis is reasonable and would have the opposite effect of contributing to the risk of MH costs increasing beyond that which is currently projected, as well as increasing indicative rate increases in the future.

PUB/Coalition I-31

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|--------------------------|----------------------------------|----------------|-------|
| Part and Chapter: | CC-24 (Derksen Report) | Page #: | 4, 20 |
| Topic: | Cost Allocation | | |
| Subtopic: | Treatment of Government Payments | | |

Preamble (if any):

On page 4, Ms. Derksen states:

1. The Residential and General Service Small – Non-Demand (GSSND) classes are negatively impacted by the PCOSS treatment of the reduction in Government payments. This change in financial circumstances has no bearing on the costs to serve these customers and should not be permitted to unduly influence RCCs. The directional indication of the inter-class impacts available for this GRA suggests that ATB rate increases are justified, should any increase be granted;

On page 20, Ms. Derksen states:

By altering MH's current rate base (and revenue requirement) to reflect the anticipated higher proportions of generation and transmission investment and reducing the relative proportion of distribution investment is likely to result in a greater benefit provided to the GSL classes as a result of reduced PGF and Capital Tax payments. Conversely, distribution intensive classes such as Residential and GSS, will benefit to a lesser degree than what is represented in the above two tables.

On page 15, Ms. Derksen states:

The reduction in generation-related costs and increase in sub-transmission and distribution-related costs is expected given that Water Rental Fees are functionalized as generation (and transmission through Net Export Revenue), which when reduced, results in reduced generation and transmission-related costs. The change in the relative proportions of functional assets also results in an impact on each class' cost to serve and RCC as can be seen in the table below:

Question:

- a) Please confirm whether the government payments (debt guarantee fee, water rentals, and capital tax) are mandatory costs incurred by Manitoba Hydro to provide service to Manitoba electricity consumers. If confirmed, please explain why a reduction in those payments has no bearing on the costs to serve Residential and General Service Small customers. Alternatively, please clarify the above statement.

- b) Please elaborate on why, in Ms. Derksen's view, the change in the relative proportions of functional assets is conceptually different from other changes in the relative proportions of COSS functions that arise in the normal course of completing cost studies.

Rationale for Question:

To understand the COSS treatment of government payments.

Response:

- a) The PGF, Water Rental Fees and Capital Tax are mandatory costs incurred by MH in the provision of electricity service to Manitobans which have a bearing on the cost to serve.

However, and importantly, Manitoba Hydro has acknowledged that it has not had any conversations with the Government on the use of the funds nor has the Government specified the intent of the fee reduction⁶¹. It is not expected that the Government intended for the disproportionate sharing of the payment relief that would see some classes benefit significantly more than other classes. Therefore, the payment reductions, in Ms. Derksen's view, should not be viewed narrowly as available only to reduce PGF, Water Rentals and Capital Tax fees.

On this basis, the reduction in the PGF, Water Rental Fees and Capital Taxes are simply a convenient mechanism for the Province to flow through general electricity rate assistance. While Ms. Derksen proffers several alternatives to applying these funds directly against the PGF, Water Rental Fees and Capital Tax costs, this is specifically to address the COS impact concerns raised.

Ms. Derksen has not been retained for purposes of assessing MH's revenue requirement. Hence, it is simply noted that there may be other alternatives for the use of the payment relief that could be addressed at the revenue requirement level given the long standing concerns raised by the PUB regarding the energy burden faced by lower-income customers, particularly in a time of major capital construction of MH which puts upward pressure on electricity rates at a level greater than the rate of inflation⁶².

- b) Often, there is no conceptual difference. The PCOSS is built upon a Rate Base/ROR methodology. Typically, assets are only allowed into Rate Base when they become operational or "used and useful". Once assets are used and useful, utilities can then begin recovering the annualized costs of the assets in rates, along with a return on investment (or Net Income in the case of MH). Net Income is allocated based on rate base – in other words there is alignment between the used and useful asset investments and the return on investment (or Net Income) the utility is allowed to earn.

However, in this case, MH is essentially saying that it wants to collect a Net Income on future assets that are not yet used and useful. And this is where the conceptual break occurs for the PCOSS. This results in a disconnect because Net Income collected today, in part for future investment, is being allocated on current rate

⁶¹ AMC/MH I-1

⁶² Order 59/18

base that has implications on each class’s cost to serve. As the level of incremental Net Income increases to support future generation and transmission investment that is not yet used and useful, the disconnect becomes larger and impacts to each class’s cost to serve will also increase.

A hypothetical example is provided in the following table:

| | Generation | Transmission | Distribution | Total |
|-----------------------------|------------|--------------|--------------|-------|
| Current Rate Base | 60% | 15% | 25% | 100% |
| Incremental Net Income (\$) | 30.0 | 7.5 | 12.5 | 50.0 |
| | | | | |
| Eventual Rate Base | 0.68 | 0.18 | 0.26 | 1.12 |
| | 61% | 16% | 23% | 100% |
| Incremental Net Income (\$) | 30.4 | 8.0 | 11.6 | 50.0 |

As can be seen in the table, incremental net income of \$50 intended for future investment in generation and transmission would currently be allocated 75% based on G&T, with the remaining 25% allocated as distribution. However, the incremental net income should be allocated 77% based on G&T and 23% based on distribution. As the incremental net income to build reserves for future generation and transmission increases, so to will the disconnect.

This means that distribution-level classes will contribute to a greater level of generation and transmission investment, through net income, in the absence of a cost allocation methodology change and/or qualitatively addressing through the interpretation of class RCC’s and rate differentiation.

PUB/Coalition I-32

| | | | |
|--------------------------|--------------------------------|----------------|---|
| Part and Chapter: | CC-24 (Derksen Report) | Page #: | 4 |
| Topic: | Cost Allocation | | |
| Subtopic: | Customer Service Costs for GSL | | |

Preamble (if any):

On page 29, Ms. Derksen states:

In reviewing the nature of these costs, it would be both justifiable and reasonable that all GSL classes bear responsibility for a portion of these costs. First, line locates for MH work, public streets and roadways, oversight of work conducted near electric plant, and outage call costs are not duplicative.

More importantly, services related to line locates for customers and roadways, building moves, safety watches, outages and marketing plans benefit not only those customers/classes who specifically make use of the services, but they provide widespread broad safety benefits to the public at large. Conversely, it is difficult to rationalize how a GSL customer does not benefit from these safety-related services associated with public streets, roadways, protection of the broad electric system, system outages and even line locates for individual customers, which in the absence of such services, could result in the shut down of portions of the electric system. Similarly, residential customers at large benefit from enhanced business development despite that these services are not directly aimed at these customers. On this basis, it is not only inappropriate to exclude the GSL >30 kV class from these costs but it is more appropriate that the larger GSL classes also be allocated these costs given the overall public benefits received.

As a result, it is recommended that GSL 30-100 kV and GSL >100 kV share in the allocation of these costs to recognize the broad public safety benefits provided.

Question:

Please confirm whether any additional rationale beyond “provid[ing] widespread broad safety benefits to the public” for allocating the customer service costs related to line locates, building moves, safety watches, outages, and marketing plans to the GSL >30 kV classes. If so, please elaborate.

Rationale for Question:

To understand if there are additional reasons supporting a change in allocation beyond those considered in Order 164/16.

Response:

As part of the Information Request process, MIPUG raised the potential of excluding the GSL 0-30kV class from the allocation of some customer service costs including line locates, building moves, safety watches, marketing R&D and call center outage calls of

approximately \$12.7 million⁶³ annually, despite the PUB findings in Order 59/18, that it is appropriate to allocate these costs to classes taking distribution level service. As part of that IR, MIPUG opined that GSL >30 kV customers do not make use of these services and requested MH to justify its allocation.

Ms. Derksen continues to express concern that, from a fairness perspective, residential customers are the primary stakeholders and ultimate risk-takers for system continuity and expansion. Industrial customers can come and go and take advantage of the robust system developed with the foresight and forbearance of the residential customer base.

From this policy level perspective, it is reasonable that these largely system safety expenditures aimed at protecting the entirety of the system, all customers, and the public at large, and not just those that make specific use of the services, should rightly be allocated to all customers, including the largest GSL classes. It is certainly unclear why all customers do not benefit from these services. It follows that it would be inappropriate to exclude the GSL>30kV class from the allocation of these costs.

If the Board finds favour in excluding this class from the allocation of these largely safety-related expenditures, it would be necessary to also exclude the allocation of some of these costs from the Residential class (and possibly other smaller volume classes) who do not directly benefit from the use of these services as MH rightfully acknowledges. In Ms. Derksen's view, this is an unnecessary extreme level of cost allocation.

⁶³ MIPUG/MH I-41 f

PUB/Coalition I-33

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|--------------------------|---|----------------|----|
| Part and Chapter: | CC-24 (Derksen Report) | Page #: | 20 |
| Topic: | Cost Allocation | | |
| Subtopic: | Future Revenue Requirements and Functionalization | | |

Preamble (if any):

On page 20, Ms. Derksen states:

For purposes of the PCOSS, what is most critical is generally not the overall magnitude of the rate increase but rather, the nature/type of the investments. That is, whether the rate increase to build Reserves is for anticipated expenditures related to generation, transmission or distribution. Given that MH's rate proposals are to support future investment primarily related to generation and transmission, the assumption underpinning the PCOSS scenarios in the two tables above that applies the increase in the PGF and Capital Tax by reducing each revenue requirement cost on proportionate basis is not appropriate. This is because future investment is expected to be significantly generation and transmission intensive which, all else equal, will change the functional cost makeup by increasing generation and transmission investment and reducing the relative proportion of distribution investment. In order words, MH's rate ask is disconnected from its current underlying rate base used in the PCOSS for the allocation of current expenditures/capital investments.

Question:

Please confirm or otherwise explain whether Ms. Derksen is advocating for future changes in the revenue requirement to be reflected in the current year's PCOSS.

Rationale for Question:

It is unclear whether Ms. Derksen is recommending future revenue requirements and functionalization of costs be reflected in PCOSS26.

Response:

Yes. It is becoming clear that MH's one year snapshot PCOSS is unable to accommodate the degree of volatility of its operations for purposes of depicting class RCCs and the translation to rates/rate differentiation, despite the level of smoothing underpinning some of MH's forecasts. In a steadier state environment, MH's PCOSS was better able to keep pace, and, arguably, provide a better dependable depiction of class cost to serve.

Incorporating future revenue requirements in the current PCOSS is certainly one way of better understanding the influence of future cost changes on class cost to serve. Running multiple cost of service study scenarios in addition to the version advanced by the Corporation is another, perhaps preferable way, of understanding the degree of future changes on class cost to serve and RCCs. This is generally currently occurring through the information request process. However, Ms. Derksen is of the view that such PCOSS scenarios are better included as part of the Corporation's GRA to understand the range

of potential impacts to class RCCs that were less critical under the largely ATB rate setting framework of years past.

PUB/Coalition I-34

| | | | |
|--------------------------|--|----------------|----|
| Part and Chapter: | CC-24 (Derksen Report) | Page #: | 21 |
| Topic: | Cost Allocation | | |
| Subtopic: | PCOSS Impacts from Reductions in Government Fees | | |

Preamble (if any):

On page 21, Ms. Derksen provides a chart showing the impacts to RCCs from reductions in government fees (debt guarantee fee, water rentals, and capital tax):

Chart 5: Overall Class RCC & Net Cost Due to Government Payment Relief²²:

| CLASS | (1) PCOSS26 RCC With Higher Fees and Taxes | (2) PCOSS26 RCC | (3) (2 – 1) Differential Benefit due to Reduced Fees and Taxes | (4) Overall Direct Benefit due to Reduced Fee | (5) (3 + 4) Combined Benefit due to Reduced Fee |
|----------------|---|-----------------------|---|---|--|
| Residential | 97.4% | 96.9% | -0.5% | 13.2% | 12.7% |
| GSS Non Demand | 108.4% | 108.0% | -0.4% | 13.2% | 12.8% |
| GSS Demand | 95.9% | 96.0% | 0.1% | 13.2% | 13.3% |
| GSM | 97.4% | 97.8% | 0.4% | 13.2% | 13.6% |
| GSL 0-30 kV | 99.9% | 100.9% | 1.0% | 13.2% | 14.2% |
| GSL 30-100 kV | 108.1% | 110.4% | 2.3% | 13.2% | 15.5% |
| GSL >100 kV | 108.0% | 110.6% | 2.6% | 13.2% | 15.8% |
| A&R Lighting | 108.3% | 104.2% | -4.1% | 13.2% | 9.1% |

Question:

Please explain how much of the Residential, GSS Non-demand, and GSL differential benefits are related to the reduction in water rental fees.

Rationale for Question:

To understand the magnitude of the test year's change in government payments which are the reduction in the debt guarantee fee and elimination of the capital tax.

Response:

The annualized impact associated with the reduction in Water Rental Fees is provided in Table B below⁶⁴. As the RCCs can be difficult to interpret at times, focus is placed on the net cost allocation by class.

Table A provides the overall PCOSS26 impacts, on an annual basis, as a result of all payment reductions.

As can be seen, on an annualized basis based on PCOSS26, the Residential class is allocated approximately \$5.2 million more than average which is largely a result of the \$4.2 million less than average allocation to the largest GSL class. Of the \$5.2 million higher cost allocated to the Residential class, approximately \$3.2 million relates to lower Water Rental Fees; conversely, approximately \$2.2 million of the less than average cost allocation, on an annual basis, relates to Water Rental Fees of the largest GSL class.

As Ms. Derksen notes in her evidence, it is also expected that these impacts are underestimated based on the PCOSS26 scenario assumptions which do not consider anticipated functional cost changes.

Table A: PCOSS26 Impacts – All Payment Reductions:

| CLASS | (1) PCOSS26 Net Cost With Higher Fees and Taxes (\$ million) | (2) PCOSS26 Net Cost (\$ million) | (3) (2 – 1) Change in Net Cost due to Reduced Fees and Taxes (\$ million) | (4) (3 / 1) Percentage Change in Net Cost due to Reduced Fees and Taxes |
|----------------|---|--|---|---|
| Residential | 931.5 | 936.7 | 5.2 | 0.6% |
| GSS Non Demand | 191.1 | 191.8 | 0.7 | 0.4% |
| GSS Demand | 185.5 | 185.4 | (0.0) | 0.0% |
| GSM | 270.1 | 269.2 | (0.9) | -0.3% |
| GSL 0-30 kV | 133.8 | 132.5 | (1.3) | -1.0% |
| GSL 30-100 kV | 110.5 | 108.2 | (2.3) | -2.1% |
| GSL >100 kV | 174.6 | 170.4 | (4.2) | -2.4% |
| A&R Lighting | 25.1 | 26.1 | 1.0 | 3.9% |

⁶⁴ Coalition/MH II-55, pg. 6 of 14

Table B: Water Rental Fee Reduction PCOSS Impacts:

| CLASS | PCOSS26 As Filed RCC | PCOSS26 Scenario RCC | Change in RCC | PCOSS26 As Filed Net Cost (\$ Million) | PCOSS26 Scenario Net Cost (\$ Million) | Change in Net Costs (\$ Million) |
|-------------------|----------------------------|----------------------------|------------------|---|---|--|
| Residential | 96.9% | 97.2% | 0.3% | 936.7 | 933.5 | (3.2) |
| GSS Non Demand | 108.0% | 108.2% | 0.2% | 191.8 | 191.5 | (0.3) |
| GSS Demand | 96.0% | 96.1% | 0.1% | 185.4 | 185.1 | (0.3) |
| GSM | 97.8% | 97.7% | -0.1% | 269.2 | 269.3 | 0.1 |
| GSL 0-30 kV | 100.9% | 100.4% | -0.5% | 132.5 | 133.1 | 0.6 |
| GSL 30-100 kV | 110.4% | 109.2% | -1.2% | 108.2 | 109.4 | 1.2 |
| GSL >100 kV | 110.6% | 109.2% | -1.4% | 170.4 | 172.6 | 2.2 |
| A&R Lighting | 104.2% | 105.5% | 1.3% | 26.1 | 25.7 | (0.3) |

PUB/Coalition I-35

| | | | |
|--------------------------|---|----------------|-------|
| Part and Chapter: | CC-24 (Derksen Report) | Page #: | 21,23 |
| Topic: | Cost Allocation | | |
| Subtopic: | Interclass Impacts of Government Payment Reductions | | |

Preamble (if any):

On page 21, Ms. Derksen states:

There are several potential options to address the disproportionate inter-class impacts associated with reduced Government payments, each with advantages and disadvantages:

On page 23, Ms. Derksen states:

The advantages of this option include: i) the PCOSS treatment conforms with spirit of MH's overall rate path which is seeking to build reserves (through higher Net Income) for future significant generation and transmission investment, that in the absence of government payment relief, would be higher; ii) the PCOSS will explicitly improve the current disproportionate inter-class impacts that otherwise occurs; and iii) it likely addresses the secondary impact associated with the payment relief that occurs as the functional cost make up of rate base shifts to reflect higher levels of generation and transmission investment. The disadvantage of the option is that it is less intuitive than the first option above. [underlining added]

Question:

Please explain what the interclass impacts are disproportionate to, and what the alternative is against which Ms. Derksen is assessing proportionality.

Rationale for Question:

To clarify Ms. Derksen's statement regarding proportionality.

Response:

The statement is intended to mean that based on the current PCOSS methodology, some classes benefit more than average from government payment fee reductions. This occurs because in addition to the average government payment fee reductions, there is an additional benefit that shifts some of the average government payment fee relief to most classes, away largely from the Residential class (and the GSSND class, so a small degree).

As MH demonstrates in Table 7⁶⁵, the overall average benefit provided from lower government payments is 13.2%, annually. However, because of the current PCOSS methodology, the Residential class's (and GSSND) benefit is lower than this average,

⁶⁵ Coalition/MH II 55, page 13 of 14

approximately 12.7% and 12.8% respectively. Conversely, the largest GSL class benefits by 13.2% annually plus an additional 2.6%, or 15.8%, on an annual basis. Left unmitigated, this equates to over \$5 million each year, or over \$100 million over the 20-year period, prior to any compounding effects for the Residential class.

PUB/Coalition I-36

| | | | |
|--------------------------|---|----------------|----|
| Part and Chapter: | CC-24 (Derksen Report) | Page #: | 21 |
| Topic: | Cost Allocation | | |
| Subtopic: | RCC ratio changes due to changes in government fees | | |

Preamble (if any):

On page 22, Ms. Derksen states:

3. As discussed above, because the sensitivity analysis does not consider the effects of adding large investment in generation and transmission, the true inter-class impacts shown in the table are understated.

...

The fundamental problem with this approach is that while other ratemaking objectives (including other definitions of cost or cost that may not be readily apparent in the test year) can/should be taken into account in the rate making stage in the assessment of class RCCs – frequently when it comes to rate making this qualifier is over looked and rates are required to conform to the COSS/ZOR (Range of Reasonableness) results. Further, the potential for differentiated rate increases due to recent adherence on the RCCs flowing from the PCOSS, despite that at best, RCCs are a directional indicator, and will compound, rather than improve, inter-class disparities. A further disadvantage with this approach is that the directional RCCs as provided by MH in Chart 6 above are understated because of the anticipated shift in rate base to reflect higher levels of generation and transmission investment.

Question:

- a) Please clarify which chart is being referred to, as Chart 6 appears on page 26 and relates to O&A, and the chart immediately following Chart 5 does not show RCCs.
- b) Please explain which RCCs in Chart 6 are understated and elaborate why there is a problem with across-the-board increases due to the anticipated shift in rate base reflecting higher levels of generation and transmission investment.

Rationale for Question:

To clarify the chart and findings on page 21.

Response:

Response:

- a) To clarify, it is Chart 5 that is being referred to on the bottom of page 22 and top of page 23 and not Chart 6.
- b) It is the RCCs in Chart 5 that are understated.

The problem is not with across-the-board increases, but rather, potentially with differentiated rate increases. This is because the RCCs flowing from PCOSS26 (and shown in Chart 5, column 2) do not reflect: i) the greater benefits provided to the larger GSL classes on account of government payment reductions; and ii) the higher levels of Net Income allocated to distribution-level classes, that will increase over time, for purposes of future Generation and Transmission investment.

PUB/Coalition I-37

| | | | |
|--------------------------|-------------------------------------|----------------|----|
| Part and Chapter: | CC-24 (Derksen Report) | Page #: | 30 |
| Topic: | Cost Allocation | | |
| Subtopic: | Reflecting Reliability in the PCOSS | | |

Preamble (if any):

On page 30, Ms. Derksen states:

It is noteworthy that in observing MH's system from a reliability perspective, like other electric utility systems, the reliability requirements and demands of residential customers compared industrial customers differs. Industrial customers, given the process nature of their operations are much less able to withstand or tolerate semi-frequent interruptions (such as 6-cycle interruptions), and in some cases, unable to withstand such interruptions at all. It is possible that in such circumstances, MH would invest in transmission upgrades (which can be significant) in order to moderate the potential for such interruptions, the cost of these investments is typically shared among all customers. In contrast, a residential customer can withstand much longer outages and would not notice this type of interruption. From this perspective, if the system was only built to meet residential reliability standards/needs, the overall cost to serve would be lesser.

Question:

Please explain whether industrial customers should pay more than residential customers if industrial customers desire a more reliable level of service than residential customers. If so, how would the additional amounts they should pay be quantified?

Rationale for Question:

To further explain Ms. Derksen's observations about reliability investments.

Response:

Yes. It is unclear at this time whether such incremental reliability costs can be reasonably quantified by MH. In the absence of such analysis, incremental reliability costs can only be addressed qualitatively in the assessment of class RCCs for purposes of rate differentiation at this time.

PUB/Coalition I-38

| | | | |
|--------------------------|------------------------|----------------|----|
| Part and Chapter: | CC-24 (Derksen Report) | Page #: | 31 |
| Topic: | Cost Allocation | | |
| Subtopic: | Load Research Report | | |

Preamble (if any):

On page 31, Ms. Derksen states:

Manitoba Hydro also provided an updated Load Research Report for the 2024/25 year which was revised to correct for a significant error on September 10, 2025³³, which remains unexplained. It is expected that this study was not available at the time of the preparation of PCOSS26.

Question:

Please explain whether Ms. Derksen is of the view that the 2023/24 Load Research report should be used to recalculate POCSS26 and the resulting RCC ratios in order to provide more current information with which to evaluate Manitoba Hydro's rate proposals.

Rationale for Question:

To understand whether an update to the PCOSS is recommended.

Response:

In Ms. Derksen's view, it is not necessary to explicitly reflect the 2023/24 Load Research report in PCOSS26, to the extent that the Board accepts its findings. It is these kinds of matters that are entirely the spirit and intent of the use of a Range of Reasonableness for purposes of rate setting by class.

PUB/Coalition I-39

| | | | |
|--------------------------|------------------------|----------------|--------|
| Part and Chapter: | CC-24 (Derksen Report) | Page #: | 33, 34 |
| Topic: | Cost Allocation | | |
| Subtopic: | Load Research Report | | |

Preamble (if any):

On page 34, Ms. Derksen states:

First, while MH's sophisticated Load Research program conforms with accepted statistical standards, it nevertheless still results in 99.8% of customer meter⁴³ consumption being subject to estimation and extrapolation, directionally representing up to 70% of MH's annual consumption⁴⁴. And while Load Research analysis exists from known hourly system demand and demand metering data for large industrial customers, it too is subject to estimation, extrapolation and uncertainty. Since peak loads are fundamental to cost allocation that must be derived and estimated for a significant portion of MH's load, the result is uncertainty in the PCOSS results.

Question:

Please explain whether multiple years of load research (either the prior practice of averaging several one-year load research reports or the current practice of averaging five years within one report) would help avoid estimation errors.

Rationale for Question:

To understand ways to improve the application of load research.

Response:

Not really. In Ms. Derksen's view, multiple years of load research is important for smoothing anomalies that will otherwise occur. While it is plausible that some estimation error can be moderated, class demand and energy determinations are still based on estimation techniques for 500,000 customers, that regardless of their level of sophistication, are subject to estimation error that is simply unavoidable.

PUB/Coalition I-40

| | | | |
|--------------------------|---|----------------|----|
| Part and Chapter: | CC-24 (Derksen Report) | Page #: | 40 |
| Topic: | Cost Allocation | | |
| Subtopic: | Rate Comparisons to Other Jurisdictions | | |

Preamble (if any):

On page 40, Ms. Derksen states:

The key observations flowing from this analysis are:

- MH rates for the Residential class range from 21% to 31% higher than the lowest residential rates in Canada and represent the highest rates compared to other MH class rates, or a spread of 40%;
- MH rates for customers in the equivalent to the Small Power Class are the lowest in Canada, ranging from 2% to 9% lower than any other jurisdiction; and
- MH rates for Large Power users range from 4% to 14% higher than the lowest rates in Canada.

In its response to CC/MH I-149, Manitoba Hydro showed that residential rates in Montreal are the lowest in Canada.

Question:

- a) Please provide the RCC ratios for Hydro Quebec's main customer classes. Please explain if there are significant differences in the rate classes such that the rate comparisons to Manitoba Hydro are not valid.
- b) Please explain whether there is any external policy direction, either from the provincial government or the Régie de l'énergie, that directs Hydro Quebec to target or maintain RCC ratios for certain classes.

Rationale for Question:

To understand the comparison between Hydro Quebec and Manitoba Hydro COSS results.

Response:

Response to Questions a) & b):

The relative comparison of rates across jurisdictions and its reliability has long been a source of contention. Some argue that jurisdictional rate comparisons are of little consequence because of a multitude of differences between utilities including the types

of generation (hydraulic vs. natural gas vs. coal etc), types of customers served, climate, topography, political regime, history, payments to government, and many others.

On the other hand, MH, for decades has place a high degree of value on these comparisons and have, for much of the last three decades, considered having the lowest rates in Canada as a strategic imperative, regardless of factors that may affect the degree of reliability.

Certainly, to the extent that customers consider their rates in comparison to another jurisdiction(s), it is doubtful that any consideration is given to these factors; that is, it is expected that rates are viewed at face value.

Ms. Derksen's view is that jurisdictional rate comparison, regardless of context, is one useful comparator, that should be considered in rate setting. It is unclear why this comparator would be any less relevant than the multitude of other jurisdictional comparisons including cost allocation methodologies, rate design, ZOR, return on equity, depreciation, contribution policy, O&M per customer, number of days from sign-up to service connection and so on, that are routinely used as a basis of comparison between utilities.

Jurisdictional rate comparisons have been used in Manitoba for decades, despite the legislative or self-imposed operating conditions in other jurisdictions. MH's rates have benefited by the extra provincial market in past decades enabling it to benefit from the lowest or close to the lowest rates across Canada, in part because of favourable geological conditions and foresight that made hydraulic electric generation possible – and is simply a different source of rate subsidization compared with other jurisdictions. MH's rates continue to be financed, now through extraordinary government payment reductions of nearly \$10 billion (over time). Similarly, in BC, there has been dividend payment relief, mandated rate pause, and the funding of transmission electrification programs to BC Hydro by the province in order to meet the provincial environmental objectives, aimed likely at lowering/moderating electric rates in that jurisdiction.

Further, despite class RCCs that are highly volatile depending on the chosen cost allocation methodology, the MPUB found it to be fair and equitable to apply across-the-board rate changes for much of the last three decades. More recently and importantly, in Order 101/23, the MPUB has found it appropriate to differentiate rates, to move class RCCs closer to the bounds of the Range of Reasonableness, but has done so through an attenuated and constrained bandwidth of rate differentiation maximum of – 1.0% to + 0.4%, or less, despite class RCCs that reside outside of the 95% - 105% bounds.

PUB/Coalition I-41

| | | | |
|--------------------------|---|----------------|--------|
| Part and Chapter: | CC-24 (Derksen Report) Q1 2025/26 Financial Report | Page #: | 42, 43 |
| Topic: | Cost Allocation | | |
| Subtopic: | PCOSS Impact of Reduced Net Export Revenue | | |

Preamble (if any):

On page 42, Ms. Derksen states:

Despite lower forecasted levels of NER, the inter-class impact associated with NER continues to have significant impacts on class RCCs. The table below indicates the impact to class RCCs as reflected by MH in PCOSS26 as well as the RCCs assuming that NER is reduced by 50%:

On page 43, Ms. Derksen states:

3. Current drought conditions are likely to drive NER down in the current 2025/26 Test Year and potentially in the second Test Year, depending on water storage levels, further impacting class RCCs from those depicted by PCOSS26.

On page 5 of its first quarter 2025/26 financial report, Manitoba Hydro states:

Manitoba Hydro is currently projecting a net loss for the 2025-26 fiscal year which could fall within the range seen over the last two fiscal years. The deterioration in earnings is primarily driven by lower net exports due to unfavourable water conditions and the need to responsibly manage water to rebuild storage levels to meet winter load requirements. There remains uncertainty associated with weather impacts, energy markets, and other external factors, and therefore the projected financial results are still subject to significant variability. However, even with a return to average precipitation for the remainder of the year, it is unlikely that Manitoba Hydro will recover from a net loss position for the 2025-26 fiscal year.

Question:

- a) Please explain why Ms. Derksen selected a net export revenue reduction of 50% as an appropriate factor with which to remove certain interclass inequities.
- b) If net export revenue is much lower in 2025/26 than projected in the Application because of the current drought, this would be expected to move the RCC ratios (increasing the Residential and GSS RCC ratios, and decreasing the GSL RCC ratio) if the updated net export revenue were to be incorporated into an amended PCOSS26. Please explain whether the PCOSS should be updated or how the change in net export revenue should be taken into account.
- c) If net export revenue is much lower in 2025/26 because of the current drought, and this moves the RCC ratios (increasing the Residential and GSS RCC ratios, and

decreasing the GSL RCC ratio), please explain whether and how this should be taken into account.

Rationale for Question:

To understand how net export revenue changes should be reflected in the COSS or used to interpret the COSS results.

Response:

- a) The 50% net export revenue reduction was simply chosen to understand, from an order of magnitude perspective, the impact to class RCCs.
- b) The PCOSS certainly could be updated to reflect a change in Net Export Revenue. However, it is Ms. Derksen's view that it is not necessary to update the PCOSS to address this, along with a multitude of other potential changes that can and do occur. It is understood that the PCOSS is a point in time determination of RCCs by class and it needs to be recognized as such – and the reason it is imperative that class RCC consequences of material changes are analyzed and provided in the GRA, preferably at the time of the filing – particularly in volatile periods such as the energy transition.

A Range of Reasonableness should be broad enough to capture these kinds of differences such that the RCCs flowing from a PCOSS for purposes of rate differentiation/determination are reasonably reliable – understanding that a ZOR cannot accommodate every possible issue. That said, to the extent that RCCs can fluctuate significantly to such a degree that could impact rate differentiation, is suggestive that the Range of Reasonableness is too tight. It is expected that this is one factor in the Board's determination to narrowly limit the degree of rate differentiation to not exceed -1.0% to +0.4% in recent years.

- c) Yes, lower Net Export Revenue compared to forecast should be considered in the setting of revenue by class. Lower Net Export Revenue, along with a number of other PCOSS inter-class issues raised, in Ms. Derksen's view, suggests that MH's ATB rate proposals, should a rate increase be granted, are reasonable. That said, based on recent findings of the Board, the Board has not relied mechanistically on the output of the PCOSS for purposes of rate differentiation. Instead, it has taken an attenuated, gradual approach that has limited the bandwidth of rate differentiation. In Order 101/23, the PUB found:

“...under the PCOSS24 results and the average 1.0% rate increase approved in this order, a mechanistic rate differentiation would result in an increase of 1.43% for residential and commercial customers while leading to a rate reduction of 0.49% for large industrial customers. The Board finds that this level of differentiation is not just and reasonable as it does not adequately balance cost of service criteria against the need for rate stability and affordability. The Board also finds that it would not be just and reasonable to impose a rate differentiation of 0.43% on the commercial customer classes that are already in the zone of

reasonableness, and that Manitoba Hydro's proposal for a 0.1% rate differentiation for those classes strikes an appropriate balance."⁶⁶

"...in reaching a decision on rate differentiation, the Board balanced cost of service criteria against the principles of rate stability, affordability, and gradualism. Based on this balancing, the Board finds that the timeline set out in Order 59/18 is no longer just and reasonable. The Board instead approves the level of rate differentiation proposed by Manitoba Hydro, as reflected in Column 5 of Figure 1.4. This approach reflects a more gradual move of different customer classes towards the zone of reasonableness compared to the Board's previous approach. It also reduces the level of differentiation for those classes that are already within the zone of reasonableness....

With the overall approved rate increase being less than what Manitoba Hydro applied for, the approved level of rate differentiation results in all classes — including the residential class — receiving rate increases less than inflation during each of the two fiscal years in question, while no class is receiving an overall rate decrease."⁶⁷

In the current GRA, with three proposed overall rate increases of 3.5%, represent substantially different circumstances. Rate differentiation of +0.4%, which is at the very outer end of the PUB's tolerance, would result in rate increases double the rate of inflation. This is suggestive that MH's ATB rate increases reasonably align with recent PUB rate increase tolerances, should MH's 3.5% rate increases be approved. A rate increase of less than 3.5% may allow for some minimal amount of rate differentiation, based on the PUB's stated tolerance, but considerably lesser than +0.4%.

⁶⁶ Order 101/23, pg. 183

⁶⁷ Order 101/23, pgs. 15 & 16