

**Public
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**MANITOBA HYDRO
FISCAL 2026-2028 GENERAL RATE APPLICATION
PUB/GSS-GSM INFORMATION REQUESTS**

October 15, 2025

PUB/GSS-GSM I-1

Part and Chapter:	GSS-GSM-05 (Davies Report) MFR 20	Page #:	12
Topic:	Recommended Rate Increases		
Subtopic:			

Preamble (if any):

On page 12, Ms. Davies states:

All this to say, Manitoba Hydro’s test year revenue requirement has built in substantial operating cost increases, fully absorbs impacts from past financial hurdles such as Keeyask GS in-service and drought, and increases costs/decreases revenue to protect from downside financial risks. To additionally set rates over the next three years that also collect over \$500 million in net income, to pre-emptively start contributing towards potential future costs that will be assessed and quantified more accurately in due course is an overreach for current ratepayers.

Recommendation: Rate increases of 3.5% for each test year are not warranted based on test year revenue requirement, which as it stands incorporates considerable cost escalations (revenue decreases) while additionally collecting over \$241 million cumulatively in net income prior to any rate increases and/or cost adjustments ordered by the PUB. Rate increases in line with inflation would balance the current economic constraints faced by ratepayers today, while still demonstrably contributing to retained earnings (cumulatively \$406 million over the test years) and maintaining Manitoba Hydro’s financial targets.

Prior to starting construction of Keeyask (\$8.2 billion) and Bipole III (\$4.8 billion), Manitoba Hydro's debt ratio was 73%, the lowest since at least 1992, as shown in MFR 20.

Question:

Please explain whether, in Ms. Davies’ view, Manitoba Hydro will be in a suitably strong financial position by the end of the rate period to add \$8.2 billion of non-revenue generating assets (\$6.8 billion HVDC refurbishment and \$1.4 billion dispatchable capacity resources) to its asset base and debt levels if rate increases in line with inflation are approved for each of the test years.

Rationale for Question:

To help evaluate the recommended rate increases.

Response:

There are many indications that support Manitoba Hydro’s ability to maintain a suitably strong financial position by the end of the rate period to add non-revenue generating assets. The key, in Ms. Davies’ view, *at this time* is how much of the responsibility for

Manitoba Hydro's long-term financial health should be shouldered by ratepayers today and how much should remain the responsibility of Manitoba Hydro and the provincial government (given its recent directions increasing decision-power on Manitoba Hydro expenditures) to improve through cost efficiencies and more detailed capital planning.

Indications in support of Manitoba Hydro's financial position with 2% test year rate increases include:

- The recommended inflationary rate increases, would contribute approximately \$406 million to retained earnings over the test years prior to any cost decrease directives from the PUB.

In Ms. Davies' evidence, there is support to reduce test year revenue requirement in areas including O&A for salaries and wages and vegetation management specifically, while other expert evidence recommends cost controlling top-down recommendations to O&A (Bowman, Rainkie) and business operations capital (Rainkie). If revenue requirement decreases are incorporated, increased net income would contribute further to retained earnings over the test years and Manitoba Hydro's resulting financial position.

- While the current financial position (2024) has an 86% debt ratio it also includes \$3.478 billion in retained earnings. Meanwhile in 2011 (before Keeyask and Bipole III) when the debt ratio was last 73%, retained earnings were comparatively \$2.389 billion.¹ There is more retained earnings now overall to support financial risks such as drought – which comparatively has not changed much in overall financial impact since that time.²
 - At 2% rate increases over the test years, Manitoba Hydro's retained earnings would grow to a forecast level of \$3.59 billion, compared to Manitoba Hydro's proposed rate increases which would grow retained earnings to \$3.716 billion; and the debt ratio would be 85% in both instances (i.e. is not impacted by the difference in retained earnings of \$126 million).³ Again, this is before any cost savings are implemented as a result of this GRA.
- Even after the last few years of financial losses, the financial position after 2% rate increases is in line with what Manitoba Hydro expected in its Needs For and Alternatives To (NFAT) review, which approved Keeyask and the 750 MW US Interconnection. For 2028, financial projections for the resource plan that was

¹ MFR-20

² The impact of a 5 year drought during this time was \$1.553 billion as per page 17 of IFF12 (filed in support of Manitoba Hydro's Needs For and Alternatives To proceeding), while currently the impact of a 5 year drought is forecast at \$1.7 billion as per Tab 3 - Financial Forecast, page 41

³ MFR-17

ultimately approved anticipated a debt ratio of 85% and retained earnings of \$3.443 billion.⁴ Not only was Manitoba Hydro completely comfortable with this level of financial position during the NFAT, it was further supporting additional capital development with this financial position of over \$10 billion+ (Conawapa GS), in a much more expedited timeframe than the HVDC Reliability and dispatchable capacity projects.

- While the costs of both Keeyask and Bipole III ballooned following the NFAT review,⁵ at 2% rate increases over the test years Manitoba Hydro will be able to achieve almost exactly its anticipated financial position for 2028.
- Both capital projects are noted by Manitoba Hydro as being in the early stages and very preliminary.⁶ The \$6.8 billion HVDC refurbishment capital forecast seems extremely uncertain given Midgard's evidence regarding the need for near-term investment on the basis of domestic capacity requirements and the lack of detailed cost estimate (section 7.4.2 of CC-13). Additionally, the \$1.4 billion budget for a dispatchable capacity resource is not approved and has not been justified in light of the lack of resource plan. While these costs may be incurred over the coming 5-15 years, it is the responsibility of the utility to provide cost-efficient, convincing and testable evidence in support of costs that drive rate increases.
 - The HVDC refurbishment also seems to differ from Keeyask and Bipole III in controllability for financial impacts - as the work involves many parts over a long period of time (15+ years). Manitoba Hydro has the ability to pace and prioritize spending on this project in consideration for its financial position.⁷
 - Dispatchable capacity generation capital timelines are driven by a load forecast which currently includes substantial and uncertain electrification growth.⁸
 - Dispatchable capacity generation may be non-revenue generating but does have potential financial benefits in reduced import costs and/or increased export/domestic revenue. Cost-Benefit Analysis and ratepayer impacts are the types of information reviewed in an Integrated Resource Plan, providing a more fulsome understanding of anticipated impacts. For example, when

⁴ Exhibit MH-104-12-4 in the NFAT review, pdf pages 25 & 27 of 360 – Plan 5 is what was ultimately closest to what has been developed with Keeyask in 2019, the 750 MW US Interconnection built and Gas as the next generation resource after Keeyask with a 'base level' of DSM.

⁵ See for example the 2020 report to Government of Manitoba by Brad Wall which reviewed the economics of both projects, available online: https://www.manitoba.ca/asset_library/en/proactive/2020_2021/ERBK-Report-Volume1.PDF

⁶ Appendix 6.4, pages 14 & 16

⁷ Appendix 6.4, pages 15-16

⁸ As explained in GSS-GSM-5, page 7, 40% of Manitoba Hydro's long-term load growth is due to expected electric vehicle growth for example.

Manitoba Hydro used Brandon Thermal in 2024 – 2025, it was used for economic reasons as well as system reliability – providing cost savings of approximately \$2.8 million over a three-month period.⁹

- From a ratepayers perspective, increasing rates prematurely to fund unsupported future capital projects is risking intergenerational inequity, as these assets are clearly not used and useful in the test years and it is not certain when or if they will be. Rate increases in the test years are not going towards revenue requirement, it is going towards Manitoba Hydro’s reserves – therefore could be considered prefunding of future capital. While the PUB has prefunded capital projects before (Bipole III, for example with the Bipole III deferral account which pre-collected ratepayer revenue) the projects were certain, had definitive schedules and budgets and were externally approved. It is a slippery slope to approve rates based on prefunding capital development that has not been properly justified as needed and tested for cost control and pacing purposes to be in the best interest of ratepayers.
- Finally, it is unclear whether there will be a public review before the PUB for the upcoming Integrated Resource Plan,¹⁰ which would be the first time to test the need for HVDC refurbishment (as expediting this work seems to be for economic reasons related to the export market¹¹), and dispatchable capacity generation. The uncertainty developed around the regulatory compact by recent government actions is strong rationale for limiting the scope of review in rate applications to what is known in order to make sure ratepayer interests and impacts are safeguarded and that it remains the responsibility of Manitoba Hydro to maximize cost efficiencies.

Ultimately, over the course of this proceeding, the PUB will need to decide between strong protection of ratepayer interests where prefunding of capital has not been justified or allowing extra revenue to prefund potential future capital from approving rates above inflation (ie. cumulatively collecting an additional \$126 million over the test years if the 3.5% rate increases are approved over 2%).¹²

⁹ GSS-GSM/MH II-24a

¹⁰For example, GSS-GSM/MH II-25, page 2 of 3, states “including *potential* review of Manitoba Hydro’s Integrated Resource Plan...”, implying that a public review of the IRP is not guaranteed.

¹¹ Exhibit CC-13, Evidence from Midgard Consultants, section 7.4.2

¹² As explained in GSS-GSM-5, page 11

PUB/GSS-GSM I-2

Part and Chapter:	GSS-GSM-05 (Davies Report) CC/MH I-47	Page #:	14, 16
Topic:	Vegetation Management		
Subtopic:	Impact on SAIDI and SAIFI		

Preamble (if any):

On page 14, Ms. Davies states:

While reliability improvements should always be strived for, they are not a blanket justification for increased costs. Compared to other Canadian utilities there does not appear to be an issue with frequency or duration of outages – of which tree contact is only a percentage of the issue.⁴³ Manitoba Hydro's current approach to prioritize areas at highest risk of outage and customer density seems to have efficiently maintained favourable reliability levels compared to its peers.

In its response to CC/MH I-47, Manitoba Hydro lists the factors that cause distribution-level outages: trees and vegetation 24.2%; condition-based equipment failures 28.2%.

On page 16, Ms. Davies states:

Recommendation: Longer-term, to ensure Vegetation Management is undertaken in a manner that maximizes expenditure while protecting rate impacts, the PUB should direct Manitoba Hydro to include in its long-term Vegetation Management Plan:

iii) Reporting on how Manitoba Hydro is addressing qualified labour shortages, including retention strategies to actualize cost efficiencies from retaining experience of production and crew (even though they are externally contracted).

Question:

- a) Recognizing that Manitoba Hydro's SAIDI and SAIFI are better than the Canadian average, please explain whether increasing vegetation management activities can still improve SAIDI and SAIFI scores more economically than capital investments that address condition-based equipment failures. Please explain how this could be assessed to determine the most optimal use of funds.
- b) Notwithstanding the recommendation to maintain current efforts of vegetation management, if Manitoba Hydro is ramping up its vegetation management activities and there are labour shortages, please explain whether Manitoba Hydro should consider on-boarding skilled arborists and undertaking these activities with internal resources. Please provide the pros and cons of this approach.
- c) What specific benchmarks, if any, does Ms. Davies recommend for a vegetation management plan?

Rationale for Question:

To understand the trade-offs between operational spending on vegetation management versus capital spending.

Response:

- a) Generally speaking, it's possible that increased vegetation management activities could help improve SAIDI and SAIFI scores more economically than capital investments that address condition-based equipment failures. However, Manitoba Hydro does not presently include this type of assessment in its development of vegetation management plans.

Longer-term benchmarking of SAIDI and SAIFI outages split by primary reason for outage along with a review of individualized spending would likely provide the ability to compare the incremental value in reliability per dollar spent on vegetation management vs. capital spending.

- b) In Manitoba Hydro's evaluation of cost efficiencies for its Vegetation Management Plan, consideration for hiring internal skilled resources compared to procuring external services is likely a valuable step to ensure activity undertaken is done at the best value.

Pros of hiring skilled labour (arborists) for higher risk vegetation management activities include maintaining a skilled knowledge base and higher level of responsiveness to maintain and evaluate contracts, more consistent program completion and assessment of risk with consideration for internal priorities and designs, and longer-term activity and planning efficiencies.

Cons for hiring skilled labour (arborists) over contracting externally includes labour flexibility (especially regionally), potential need for flexibility of these services due to restrictions in work time frames (if there are weather related limitations as an example), and overall cost competitiveness and availability of skilled arborists to fill an internal position.

It is important to distinguish the types of activities that would more appropriately be managed through external contract compared to those that are more efficiently done with internal resources – i.e. between skilled work and general vegetation management activities.

The major issue is that this does not seem to be a common approach employed by North American utilities, except for Hydro One.¹³

To be clear (based on the wording of the question above), the recommendation in Ms. Davies' evidence is not explicitly to retain existing levels of vegetation management. Specifically on page 16 the recommendation states that "a more measured cost increase in the test years that prioritizes the highest priority backlog

¹³ As noted by Hydro One on its Vegetation Management section of its website that it is the only utility in North America with a "dedicated, in-house vegetation management team", available online: <https://www.hydroone.com/about/corporate-information/vegetation-management>

until a long-term Vegetation Management Plan can be filed seems reasonable for ratepayers while still prioritizing reliability and safety.”

While not explicitly provided in the evidence, it would be more reasonable to incorporate a more linear cost increase into the test years than presently proposed. Manitoba Hydro is currently forecasting a 108% cost escalation in Distribution-related O&A vegetation management from 2024/25 – 2031/32,¹⁴ however 92% of this growth is occurring over the three test years. Pacing the increased activity across the years 2024/25 – 2031/32 would still result in annual spending increases of 11% to address backlog and still ends up more than doubling current expenditure levels, it just does so in a more measured way. This seems extremely reasonable, especially for the test years where there is no formal Vegetation Management Plan or benchmarking to justify or ensure the level of expenditure Manitoba Hydro is proposing will provide beneficial results.

This is shown in the table below:

Table 1: Paced Vegetation Management Annual Expenditures for Distribution O&A¹⁵

\$ Millions	Budget 2025	Test Years			Forecast				Cumulative Variance
		2026	2027	2028	2029	2030	2031	2032	
Distribution O&A									
Manitoba Hydro Proposed:	16.9	23.4	29	32.4	33.1	33.7	34.4	35.1	18.2
Increase %		38.5%	23.9%	11.7%	2.2%	1.8%	2.1%	2.0%	107.7%
Spending at Measured Annual Increase	16.9	18.8	20.8	23.1	25.7	28.5	31.6	35.1	18.2
Increase %		11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	107.7%
Resulting Cost Differential	0.0	-4.6	-8.2	-9.3	-7.4	-5.2	-2.8	0.0	

- c) To start, continued monitoring of reliability improvements, such as outages primarily caused from tree contact, and comparing tree specific outage statistics to other utilities provides a long-term benchmark of overall customer perceived outcomes from vegetation management activities. Benchmarking the number of customer complaints received for tree-related outages can also help to identify the relative level of importance customers place on outages and if vegetation management is improving customer satisfaction overtime. These would be lagging indicators though, so longer-term trends would be more important to assess than short-term or individual year results.

Other specific benchmarks that can help assess the reasonableness and effectiveness of a vegetation management plan include:

- i) Efficiency/Performance measures for effectiveness of expenditures – this includes reporting unit (or span) based costs by activity (tree trimming/pruning,

¹⁴Appendix 6.2, page 44

¹⁵ Manitoba Hydro proposed spending from response to GSS-GSM/MH I-1(a)

brushing, herbicide), and number of spans completed year over year to measure progress and cost efficiencies.

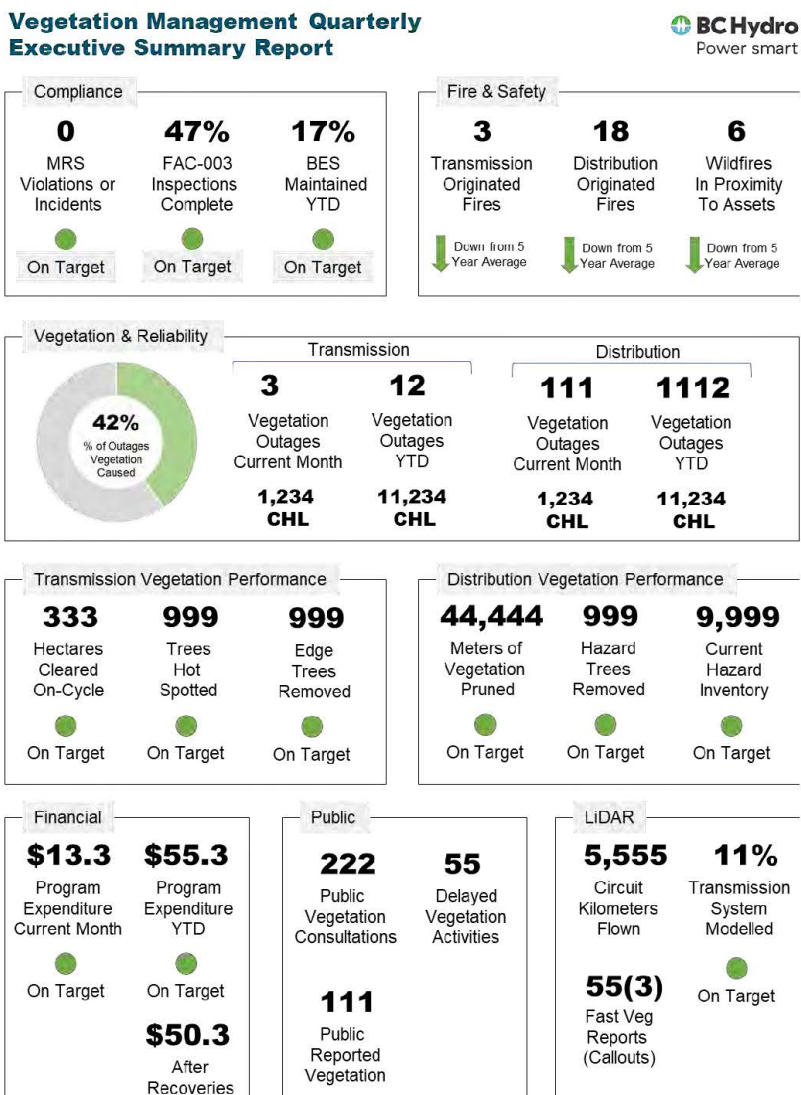
- (1) Where there are major regional differences in unit costs (based on type of vegetation, distance of spans, or activity between urban/rural, etc.) splitting these spans and unit costs/span up by area can be helpful to understand potential complexities/cost-driver distinctions. This could also apply to asset type (for example, if there are meaningful activity differences in brushing required between single- and three- phase lines).
- (2) Comparing annual spans completed by each program to total number of system spans is necessary to benchmark the overall cycle time (or how much of the system is managed each year) and whether Manitoba Hydro is making progress on this and/or meeting a target cycle time.
 - (a) Cycle times should be evidence backed (i.e. linked to vegetation growth rates) and likely vary by region and/or by type of activity (which will be required in different intervals for tree trimming/pruning, brushing, herbicide tree control).
- ii) As Manitoba Hydro has identified a significant backlog (approximately 300,000 spans),¹⁶ tracking the overall percentage of backlog addressed each year is also a meaningful benchmark.
- iii) Tracking climate-related considerations for vegetation management (from changes to vegetation growth rates to wildfires/storm impacts) could be a useful metric to establish now for objectives that may have increasing importance in future. For example, this could include tracking of activity undertaken primarily due to identified wildfire risk, or identifying areas of highest concern where cycle times may be advanced compared to average.
- iv) For vegetation management employment, worker/contract turnover rates could be considered as a benchmark to assess cost-effectiveness from retention in experienced employees/contractors.
- v) Safety is also valuable to track with key performance indicators, including measuring safety incidents due to vegetation management activities (for example, could be measured by level of severity, lost days/FTE due to workplace, etc).

BC Hydro provided an illustrative example of its quarterly benchmarking report in its most recent Vegetation Management Plan which includes some of the above-mentioned indicators but importantly, commits to consistent, transparent and comparable reporting:¹⁷

¹⁶ Response to GSS-GSM/ MH I-2(a)iv

¹⁷ BC Hydro provided its latest Vegetation Management Plan as Appendix G in the 2023 – 2025 Revenue Requirements Application. Figure from pdf page 479 of 2694, available online:

Figure G-8 Illustrative Example Quarterly Vegetation Executive Summary Report



* Actual report to be developed in fiscal 2022 as part of the delivery of the VMS. Illustration purposes only.

Efficiency metrics can also be benchmarked across peer utilities. BC Hydro included two jurisdictional benchmarking reports in support of its latest Vegetation Management plan (although both were filed confidentially) – 1) First Quartile Benchmarking report, which is undertaken annually and focuses on financial expenditure (distribution system cost per customer), reliability and overall performance; and 2) the CEA Vegetation Management Benchmarking report which provided specific approaches as well as overall cycle durations for participating utilities.¹⁸

https://docs.bcuc.com/documents/proceedings/2021/doc_64006_b-2-1-bch-f23-f25-rra-appendix-public.pdf

¹⁸ Ibid, detail on benchmarking reports is provided at pdf pages 463 – 464 of 2694

Manitoba Hydro already has benchmark targets it reports that compare vegetation management spending compared to peers, which are useful to maintain.¹⁹

The intention for benchmarking is not to micromanage line-by-line spending, but to measure results and effectiveness such that Manitoba Hydro can provide an evidence-based Vegetation Management Strategy over time to maximize benefit to ratepayers and allow for a more effective review to take place in future rate hearings.

For example, in a previous rate filing, Hydro One filed a Vegetation Management Plan that provided the estimated cost increase percentage to decrease the cycle time from 8 years to 7 years. However, the Ontario Energy Board found that reliability improvement benefits had not yet materialized from past spending increases and that activity cost efficiencies needed improvement. It did not approve Hydro One's forecast cost increase and instead noted that Vegetation Management was an area where expenditure reductions should be achieved.²⁰ Since then, the auditor general recommended a changed approach to prioritize hazard tree removal and optimal cycle clearing for areas of largest impact to customers which Hydro One implemented allowing for flattened vegetation management expenditures.²¹

Benchmarking may look different for the Transmission system, where reliability standards dictate clearance requirements by voltage class and benchmarking could be developed in relation to these requirements (including unit cost by activity per span split by voltage, and measuring reliability standard violations as a result of vegetation).

¹⁹ GSS-GSM/MH I3c

²⁰ OEB Order EB-2009-0096, pages 19 – 20, available online : https://www.oeb.ca/oeb/Documents/2010EDR/Dec_Reasons_HONI_20100409.pdf

²¹ As detailed in Hydro One's 2018 – 2022 Distribution Rate Application in Matter EB-2017-0049, Exhibit C1, Tab 1, Schedule 2, starting on pdf page 35 of 1139, available online: https://www.hydroone.com/abouthydroone/RegulatoryInformation/dxrates/20182022dxrates/Documents/HONI_Update_Ex_C_20170607.PDF

PUB/GSS-GSM I-3

Part and Chapter:	GSS-GSM-05 (Davies Report)	Page #:	18
Topic:	SAP S/4 HANA		
Subtopic:			

Preamble (if any):

On page 18, Ms. Davies states:

Recommendation: In setting rates for the 2027/28 test year (and the longer-term implications of this) the PUB should consider taking one of the following approaches:

1) Capitalize any expenditures related to the SAP S/4HANA ERP project until Manitoba Hydro can justify the magnitude of expenditure and the appropriate level of costs to amortize in rates;

Rule 7 of subsection 39(5) of *The Manitoba Hydro Act* currently states that:

7. If the regulator directs the corporation to defer the recognition of costs or revenue, it must also specify, as part of that direction, when, or the conditions under which, the corporation may recognize those costs or that revenue.

Question:

- a) Is it Ms. Davies' understanding that the PUB may direct the capitalization of SAP S/4HANA expenses without establishing a regulatory deferral account? If so, please elaborate. If not, please clarify what, if any, conditions Ms. Davies is recommending that the PUB impose under Rule 7.
- b) Does Ms. Davies have a view on the appropriate amortization period for an SAP S/4HANA account, if approved by the PUB?
- c) To what extent should the amortization period be based on the terms of SAP's software licensing agreement, including any renewal terms?

Rationale for Question:

To clarify Ms. Davies' recommendation regarding the deferral or capitalization of SAP S/4HANA expenses.

Response:

- a) As clarification, the recommendation quoted above does not comment on whether or not a regulatory account should be established in this proceeding, it focuses on ensuring SAP project expenses are not included in revenue requirement for the test years (either expensed or collected through a regulatory deferral account).

It is understood that accounting rules may require software licenses to be treated as an O&A expense, if this is the case and accounting rules are applicable to revenue requirement for rate setting purposes,²² then establishing a regulatory deferral account seems appropriate as it replicates a more typical depreciation expense for capitalized assets – as long as interest isn't being accrued. It's not clear if an account needs to be established in this rate proceeding, especially if the PUB disallows recovery of these costs in the test years.

If the PUB determines it needs to establish a regulatory account for these test years, similar to Mr. Rainkie's recommendation (CC-23, pg. 104 – 106), it is recommended that approval should be on an interim basis with an upper limit for SAP project spending with final approval of the account and overall spending included in the account determined once a fulsome business case is provided in accordance with PUB Order 101/23.²³

b) & c)

Without a fulsome business case it seems premature to recommend a definitive amortization period – especially given the overall cost of the project, the useful life and potential long-term operational cost efficiencies are sure to be important factors to justify project costs in evaluation against alternatives.²⁴

While a 10-year licensing agreement is Manitoba Hydro's justification for a 10-year amortization period this does not recognize the long-term economic benefits and usefulness of this project, and therefore linking an amortization period to one licensing term seems to be too conservative.

The \$156 million cost also includes business transformation activities (i.e. significant changes in processes and technology to do work differently and more efficiently)²⁵ - including implementation and customizations, transitioning, and training to switch from the current SAP EEC ERP system, which has had a useful life of 20 years, to the new SAP S/4HANA ERP. Simply put, the amount of cost and effort to implement this new system is not justifiable for only one 10-year licensing term, and it would be concerning to approve a project of this nature and magnitude if it was only useful for 10 years.

SAP has an innovation commitment for SAP S/4HANA until 2040,²⁶ however implementation from SAP ECC to SAP S/4HANA has been slow with a high

²² It is understood that IAS 38 is currently being re-evaluated specifically for cloud computing arrangements including SAP S4/HANA, see for example the IFRS presentation from October 2025: <https://www.ifrs.org/content/dam/ifrs/meetings/2025/october/asaf/ap2-potential-changes-recognition-requirements.pdf>

²³ Pages 10 - 11

²⁴ For example, IBM reported 30% reduction in infrastructure-related operating costs following migration to SAP's cloud ERP platform from consolidations and automation, as reported May 21, 2025 by CIO: <https://www.cio.com/article/3988351/ibms-massive-sap-s-4hana-migration-pays-off.html>

²⁵ GSS-GSM/MH II-2c

²⁶ SAP website, available online: <https://support.sap.com/en/release-upgrade-maintenance/maintenance-information/maintenance-strategy/s4hana-business-suite7.html>

number of customers anticipated to remain on the legacy system past 2027²⁷ and even to 2033 as SAP has recently extended their offboarding transition program for large customers from 2030 to 2033.²⁸ This hesitancy and difficulty to switch to SAP S/4HANA, even though its been available since 2015, speaks to the importance of a company's enterprise system and the complexity to make a transformational change – not something that is going to be done once every decade.

While there are not extensive examples of implementation of SAP S/4HANA costs in rates given the current transition timing, a few examples include:

- BC Hydro's transition to SAP S/4HANA was recently approved by the BCUC in February 2025, at an authorized cost estimate, including a contingency reserve, between \$66.3 - \$73.2 million (less than half Manitoba Hydro's estimate even though its annual revenue requirement is over double Manitoba Hydro's). BC Hydro's evaluation of the SAP S/4HANA project compared to alternatives and estimated annual bill impacts used a 13 year time horizon, based on its anticipated commitment of at least two 6.5 year subscription terms.²⁹
- Consumers Energy (natural gas distribution company in Michigan), requested a 15-year amortization period for its SAP S/4HANA costs via deferred accounting treatment (including the cloud implementation costs for the Software as a Solution 'Saas' that will be part of the SAP S/4HANA project over the 15-year period).³⁰ The amortization period was justified by the utility because, "[t]his software asset will provide significant value and functionality over an extended period, as it is deeply integrated into the Company's business processes, and there is a substantial investment in its development and integration. The benefits of continuing to use the existing software outweigh the costs of transitioning to new software sooner than 15 years. This approach will also benefit customers by spreading these costs over 15 years to minimize the impact on customer rates."³¹ This treatment was recently approved by the Michigan Public Service Commission.³²
- Teco Peoples Gas (an Emera company) has filed with the Florida Public Service Commission to use a 20-year amortization period for SAP S/4HANA

²⁷ As reported by CIO on May 21, 2025, available online: <https://www.cio.com/article/3988351/ibms-massive-sap-s-4hana-migration-pays-off.html>

²⁸ SAP website feature, updated March 7, 2025, available online: <https://news.sap.com/2025/02/sap-erp-private-edition-transition-option-navigate-complex-rise-with-sap-transformations/>

²⁹ As per pages 7 & 14-15 of BCUC Order G-44-25, available online: <https://www.ordersdecisions.bcuc.com/bcuc/orders/en/522648/1/document.do>

³⁰ MPSC Case No. U-21806, Consumers Energy, Natural Gas Distribution Utility in Michigan, filed with the Michigan Public Service Commission on December 16, 2024, pdf pages 35-36 (application pages 14-15) and 152 – 159 (application pages 104 – 111), available online: <https://www.consumersenergy.com/-/media/CE/Documents/rates/u-21806-application.pdf>

³¹ Ibid, pdf page 159

³² Order U-21806 by the Michigan Public Service Commission, September 25, 2025, page 226 – 227, available online : <https://adms.apps.lara.state.mi.us/Mpsc/ViewCommissionOrderDocument/27261>

software (through a FERC depreciation subaccount) as the previous SAP ERP system was on the market for 33 years and its anticipated the SAP S/4HANA replacement will have similar lifespan in the market, so the 20 year period will more appropriately reflect the asset's life.³³ This matter has not yet been decided on by the Florida Public Services Commission.

It seems most appropriate to determine an amortization period along with review of the business case and final approval of a regulatory deferral account, as recommended in part (a) above, but from the information that is on the record and publicly available, 10 years seems far too conservative and does not appropriately represent the enduring and economic value of upgrading an ERP system.

³³ Direct Testimony on behalf of Peoples Gas System in the Petition for Rate Increase by Peoples Gas System, filed March 31, 2025 with the Florida Public Service Commission, pdf pages 22 – 23 (application pages 19-20), available online:
https://www.peoplesgas.com/496a7c/contentassets/b3b0e5ff2a7e4a1c89cbbef5eb0c46a6/05.-final_direct-testimony-and-exhibit-of-christian-richard.pdf

PUB/GSS-GSM I-4

Part and Chapter:	GSS-GSM-05 (Davies Report)	Page #:	20
Topic:	Operating and Administrative Expenses		
Subtopic:	Salaries and Wages		

Preamble (if any):

On page 18, Ms. Davies states:

The regulatory compact is meant to introduce cost pressures in lieu of competition - adding sweeping cost escalation to the O&A forecast in addition to specific line item increases does not encourage cost containment. The PUB should set rates for the test years that include reduced O&A spending. At a minimum for the test years, operational Salaries & Wages and Overtime should be held at a flat 2% inflationary factor. If increases are needed in this category at a higher level to cover union settlements it should come from offsetting savings in other O&A cost categories. Inflationary increases would reduce O&A expense in the test years by approximately \$50 million cumulatively (approx. \$14.75 million reduction to annual Salaries & Wages, \$1.5 million reduction to Overtime).

Question:

Please provide the rationale for choosing a 2.0% inflationary factor. Are there reasons beyond general cost control because of which Ms. Davies is recommending this rate?

Rationale for Question:

To clarify Ms. Davies' recommendation regarding salaries and labour escalation.

Response:

The recommendation of a maximum increase to Salaries & Wages and Overtime in the test years of 2% escalation is based on Manitoba Hydro's general O&A increase (which is 2%), in line with general inflation for the forecast period,³⁴ and can still reasonably absorb union settlement wage increases in the test years of 2.75% with some cost control in other areas. This was also in consideration of the large increases already absorbed in these cost categories over the past three years (cumulatively 19% for Salaries & Wages and Overtime from 2021/22 – 2024/25), and noting a lack of increases to FTEs over the test years, so there are no increases needed in these cost categories for increased personnel.

³⁴ Spring 2024 Economic Indicators for Manitoba Real GDP, as per MFR 58, page 2

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Part and Chapter:	GSS-GSM-05 (Davies Report)	Page #:	28
Topic:	Load Research Report		
Subtopic:			

Preamble (if any):

On page 28, Ms. Davies states:

Broadly speaking, while there are a few deviating results happening in the 2023/24 1-Year data (for example, many GSL rate classes having CP load factors above 100% - well above the other year data sets, and Street Lighting 2023/24 CP load factor for the one year data set is quite low while the 5 yr average data set for 2023/24 is quite high), and the Residential class is hard to compare for the 1 year recent results, the CP and NCP load factors across all data sets show relatively consistent behaviour.

...

In adopting the 5 year methodology, the Load Research results have become much less transparent, system cost drivers and potential price signals are being muted, and major changes in customer demand usage trends will take years to start to show up in results (such as conversions to electric heat, increased installation of heat pumps, increased electric vehicle usage, etc.).

Question:

- a) Please explain the meaning of coincident peak load factors in excess of 100%, or explain how such values may result.
- b) Please provide the pros and cons of Manitoba Hydro's new load research methodology compared to the prior methodology (2014/15 report using 8 years of data).

Rationale for Question:

To understand the meaning of greater than 100% load factors.

Response:

- a) The Coincident Peak Load Factor is simply the average customer class load (energy usage over the year divided by 8,760, number of hours in a year) divided by the class coincident peak (CP). It can be in excess of 100% if the class coincident peak occurs at a low usage point, i.e. when peak demand is being used at a lower level than the average usage (or conversely when average energy usage exceeds the usage at system peak).

This can happen for customer classes that are not coincident (not using energy in a manner that drives peak usage), which is the case in the 2023/24 Load Research

one year data set for the GSL 30-100kV, GSL >100kV curtailable and GSL >100kV rate classes.

- b) In evidence preparations, Ms. Davies did not review the 2014/15 Load Research methodology in detail as it was understood to be dated.

Generally speaking, it is understood that positives for the 2022/23 load research methodology includes a wider sampling of customer data to develop class input statistics, and a shorter range of years used in averaging coincident peak results (5 instead of 8).

A con for the 2022/23 method compared to the 2014/15 Load Research Report methodology is the lack of transparency in results from the amount of manipulation undertaken to the input data with the 'ranking and averaging' step and the artificially reconstructing merged results (explained in detail in Appendix A of Mr. Bowman's evidence, Exhibit MIPUG-08). While the 2014/15 report did also overly smooth coincident peak demand estimates by selecting the top 50 values and using an 8-year rolling average (i.e. effectively using 400 peak hours to develop the CP estimate), the separate annual calculated CP values were maintained by the simple averaging formula. While this will dilute near-term customer class load profile changes and mute cost drivers by over averaging, it at least is more transparent and underlying values that support the final CP calculation can be clearly identified.

Load research provides important detail to help understand customer class usage profiles and cost drivers over time. The allocation step in the Cost of Service study is designed specifically to assign costs based on cost causation. Specifically for the Coincident Peak and Non-Coincident Peak allocators, they are used to ensure the customer classes that drive the system capacity costs and more local capacity costs are properly allocated those costs. Any muting of the underlying peak cost drivers – basically everytime the underlying peak is averaged or ranked or muted, is diminishing the effectiveness. Occasionally this is useful when results are anomalous or potentially very inconsistent year-over-year, but that should be decided with a full understanding of the data being reviewed. While the 2014/15 methodology averaged results by using 400 values over 8 years, the 2022/23 method essentially mutes each peak and reshuffles the level of overall importance by trying to smooth potential anomalous results. It goes too far, a major con of the method.

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Part and Chapter:	GSS-GSM-05 (Davies Report)	Page #:	30
Topic:	Cost of Service Study		
Subtopic:	Distribution Classification to Demand and Customer		

Preamble (if any):

On page 30, Ms. Davies states:

When using 100% demand-classification, effectively the customer will not be allocated any distribution plant costs in the Cost of Service (for Poles & Wires and Transformers especially). This is standard industry practice and widely accepted, including in the NARUC Cost Allocation Manual:

When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs.

Question:

Please clarify whether Ms. Davies is stating that a 100% demand classification is standard industry practice or whether a split classification is standard industry practice.

Rationale for Question:

To clarify the statement reproduced in the preamble.

Response:

Not confirmed.

To clarify, the above statement should read:

When using 100% demand-classification, effectively the customer will not be allocated any distribution plant costs in the Cost of Service (for Poles & Wires and Transformers especially). **Splitting the classification of distribution plant costs (primarily for Poles & Wires and Transformers) between both demand and customer** is standard industry practice and widely accepted, including in the NARUC Cost Allocation Manual:

When the utility installs distribution plant to provide service to a customer and to meet the individual customer's peak demand requirements, the utility must classify distribution plant data separately into demand- and customer-related costs. [added text for clarification has been bolded]

PUB/GSS-GSM I-7

Part and Chapter:	GSS-GSM-05 (Davies Report)	Page #:	38
Topic:	RCC Rebalancing		
Subtopic:	Net Export Revenue		

Preamble (if any):

On page 38, Ms. Davies states:

The future of export revenues is an important component to consider for RCC ratios, as 2025/26 and PCOSS26 by extension is based on an anomalous year of export revenues that is not anticipated moving forward. PCOSS26 results include offsetting export revenue of \$867 million,¹³² however thereafter export revenue is forecast to decrease by almost \$100 million in 2026/27 to \$771 million, and further thereafter – largely a result of decreasing on-peak export prices and expiring long-term contracts.¹³³ As this GRA covers three test period years this is a worthwhile qualitative consideration for differentiated rates over the full test period.

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:

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 ratios) 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.

Rationale for Question:

To understand the impacts of decreased net export revenues on the PCOSS results and rate rebalancing.

Response:

It is reasonable to update PCOSS26 if the Board has concerns with the accuracy of the underlying forecast inputs driving results and preparation of rate class rebalancing.

The PUB has traditionally adopted a 95% - 105% zone of reasonableness that will absorb a good measure of year over year fluctuations and in consideration of the fact that forecast input values will not provide perfect results in actuality.

For example, in response to GSS-GSM/MH II-4b, Manitoba Hydro provides RCC ratios if export revenues in PCOSS26 were more in line with 2026/27 forecast values (i.e. a decrease in net export revenue from \$867 million to \$771 million). The table below is pasted from this response:

Table 3 – Comparison of PCOSS26 using 2025/26 versus 2026/27 Export Revenue

CLASS	PCOSS26 RCC Export Revenue \$867 million	PCOSS26 RCC Export Revenue \$771 million	Change in RCC
Residential	96.9%	97.1%	0.2%
GSS ND	108.0%	108.2%	0.2%
GSS D	96.0%	96.1%	0.1%
GSM	97.8%	97.8%	0.0%
GSL 0-30 kV	100.9%	100.6%	-0.3%
GSL 30-100 kV	110.4%	109.4%	-1.0%
GSL >100 kV	110.6%	109.3%	-1.3%
A&R Lighting	104.2%	106.2%	2.0%

In this scenario, Residential and GSS-D have slightly increasing RCC ratios but remain within the zone of reasonableness. The GSS-ND rate class also sees an even greater increase to its RCC ratio outside the zone of reasonableness. And while GSL 30-100kV and GSL >100kV see decreases to RCCs, they are not magnitudes large enough to shift RCCs to within the zone of reasonableness. Under this scenario, A&R lighting class RCC is also outside the zone of reasonableness. Even with \$100 million reduction to net export revenue, GSS-ND, GSL 30-100kV and GSL >100kV still have RCCs significantly outside the range of reasonableness.

While reduced export revenues in 2025/26 would impact RCCs, and future decreases to net export revenues in the 2026/27 and 2027/28 test years will also impact RCCs, the GSS-ND, GSL 30-100kV and GSL >100 kV rate classes have a sustained history of RCC ratios outside of the zone of reasonableness that for fairness should be addressed and corrected over the proposed test period. For this reason, Ms. Davies recommends addressing RCCs through differentiated rates over the test years, but aiming for rate adjustments that bring classes to within the zone of reasonableness and not striving for full cost coverage (i.e. 100% RCCs).

Of note, the impact of the 2023/24 drought was approximately \$604 million compared to budget - impacting not only extraprovincial revenue but also fuel and power purchased, finance expenses.³⁵ The above example does not reach that level of magnitude (approximately 1/6 of that amount) and if this were to occur again for 2025/26 its reasonable for the PUB to request, or Manitoba Hydro to voluntarily bring forward updated information including a new PCOSS.

³⁵ Tab 9, MFR-31, page 53 of 55

PUB/GSS-GSM I-8

Part and Chapter:	GSS-GSM-05 (Davies Report) Tab 7 Section 7.2	Page #:	38 8
Topic:	RCC Rebalancing		
Subtopic:	GSL >100kV Rebalancing		

Preamble (if any):

On page 38, Ms. Davies states:

The estimated cumulative impact of holding rates steady for the GSS-ND and GSL >30kV rate classes to correct for high RCCs over the test years is \$76 million. As this results in RCCs for each class approaching 100% it is likely 0% rate increases are not fully required to satisfy the principle of reasonable cost coverage for each rate class (within 95 – 105%).

On page 8 of Tab 7, Manitoba Hydro provides the RCC results of PCOSS26

Figure 7.2: PCOSS26 RCC Results Compared to RCC Results of PCOSS24

Customer Class	PCOSS24		PCOSS26	
	RCC	ZOR	RCC	ZOR
Residential	94.4%	Below	96.9%	In
General Service Small Non-Demand	109.7%	Above	108.0%	Above
General Service Small Demand	101.8%	In	96.0%	In
General Service Medium	100.3%	In	97.8%	In
General Service Large 750V-30kV	97.9%	In	100.9%	In
General Service Large 30-100kV	112.4%	Above	110.4%	Above
General Service Large >100kV	113.2%	Above	110.6%	Above
Area & Roadway Lighting	108.2%	Above	104.2%	In

Question:

Considering the GSL >100 kV class has an RCC ratio of 110.6% which exceeds the GSS-ND and GSL 30-100 kV RCCs, please explain why Ms. Davies recommends that only the GSS-ND and GSL 30-100 kV class rates be held constant in order to move these classes within the zone of reasonableness.

Rationale for Question:

To understand why the GSL >100 kV class is excluded from the recommended RCC rebalancing.

Response:

In the above referenced quote, using the “GSL >30kV” term was intended to reference both the GSL 30 - 100kV and the GSL >100kV rate classes (i.e. as both are above 30kV).