Public Utilities Board
Régie des services publics

MANITOBA HYDRO
FISCAL 2026-2028 GENERAL RATE APPLICATION

PUB/MIPUG INFORMATION REQUESTS

October 1, 2025

PUB/MIPUG I-1

Part and Chapter:	MIPUG-08 (Bowman Report) Tab 9 MFR 31 Tab 3 Section 3.5	**Page #:**	21-22 36 33
Topic:	Corporate Allocation		
Subtopic:			

Preamble (if any):

On pages 21 and 22, Mr. Bowman states:

> Finally, the Board has now indicated the justification of "synergies" as the basis for the Corporate Allocation "may have outlived its usefulness". The Board indicates that allocation of bona fide costs between electric and gas ratepayers should be studied as part of preparing future business plans, but indicates gas customers may appropriately be allocated none of the costs of the acquisition debt, indicating: "Ordinarily a company's customers are not responsible for the cost of that company being acquired by a different company." Reflecting the same rationale, there is no ongoing rationale for retaining any allocation of Centra acquisition debt to electrical ratepayers.
>
> …
>
> Specifically, Centra acquisition debt cost would no longer reside with Centra (as customers are not responsible for the costs incurred by the acquirer), but also not reside in any way with electricity operations, as they form no part of investments or assets used, useful or required to provide electrical service.

Mr. Bowman makes the following recommendation:

> Implementing this change will result in improved electrical financial projections of $5 to $9 million per year throughout the financial forecast horizon, including the test years…The corporate allocation of debt costs which were used to acquire Centra Gas are of no ongoing relevance to electricity operations. The corporate allocation reflects no used or useful electricity assets, and should not be included in the electricity operations revenue requirement.

On page 36 of MFR 31, Manitoba Hydro states:

> Corporate allocation includes Manitoba Hydro electric operations' share of the acquisition costs relating to Centra. The total annual acquisition cost of Centra includes the interest and Provincial Guarantee Fee ("PGF") on the acquisition debt, the amortization of the acquisition and integration costs as well as the impact of a sinking fund investment by the Manitoba Hydro-Electric Board to retire Centra acquisition debt. Historically, the total ranged from $19 to $20 million annually; however, with the impact of the sinking fund investment, the total, beginning in 2023/24 ranges from $13 to $16 million annually. The finance expense portion of corporate allocation is apportioned to electric and natural gas operations based on their respective number of customers. As such, one third of the finance expense portion is charged to natural gas operations, with the remainder charged to electric operations.

On page 44 of Tab 3, Manitoba Hydro states:

> Please note, as overall financing requirements of Manitoba Hydro and its subsidiaries are managed on a consolidated basis, the Financial Forecast used in the DMS and in the discussion below refers to consolidated information.

Question

a) If not by way of a corporate allocation, how should the carrying costs related to the servicing of the $254 million in debt issues related to the acquisition be recovered? Provide an illustration of its recovery.

b) Does Mr. Bowman consider the financing costs to be used and useful for natural gas ratepayers? If so, please comment on the appropriateness of assigning the entirety of the costs to natural gas ratepayers after 20 years of the corporate allocation approach. If not, please elaborate.

c) Please explain Mr. Bowman's view as to how Manitoba Hydro should deal with the $100 million sinking fund established to retire the acquisition debt.

Rationale for Question:

To understand the revenue requirement implications of the proposed elimination of the corporate allocation.

Response:

a)

The $254 million of debt issues established to purchase the assets of Centra are not a component of providing electrical service in Manitoba. They should not be recovered from electrical ratepayers.

b)

The costs in question are a component of the investment in assets to provide service to gas ratepayers. The corporate allocation approach arose out of natural gas proceedings which attempted to implement the Board's decision in Order 208/02, which noted:

The shareholders of Hydro initiated the purchase of Centra. The ratepayers of Hydro and Centra should be held harmless as a consequence of the Transaction. Therefore, the risks and benefits associated with the Transaction and the Integration should accrue to the shareholders of Hydro.

In Board Decision 135/05, the Board concluded:

> *The Board agrees with CAC/MSOS that a total return to MH in the range of $14-16 million is adequate and, together with synergy savings, should allow MH to meet the annual costs of amortizing and financing its acquisition costs.*

In short, the debt associated with the acquisition costs were parked in Manitoba Hydro's statements, but the returns from owning Centra (assumed to be $14-$16 million) were adequate to compensate Hydro for carrying this cost. In short, gas ratepayers paid for the costs of the acquisition debt through returns to Hydro.

Under the current allocation arising from the previous Centra GRA, this outcome no longer arises. A fundamental reconsideration of the approach to carrying the Centra acquisition debt is therefore required. This is not a repeal of the 20 year approach, it is Centra's management driving the need for a revised approach given the proposals in the Centra GRA to now prevent Centra gas customers from paying valid costs of investing in gas assets and equity.

c)

Hydro's debt is managed on a consolidated basis. As such, it is a misstatement to characterize this sinking fund as being selectively established for one debt retirement purpose. This is simply $100 million in cash generated from Hydro activities (electrical related subsidiaries) that can be used to manage consolidated debt.

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Part and Chapter:	MPIUG-08	**Page #:**	14-16
Topic:	Operating Costs		
Subtopic			

Preamble (if any):

At p. 14 of Mr. Bowman's evidence, he discussed the scenario resulting from Coalition/MH-I-27U. That scenario capped operating costs at 2% escalation, resulting in the 20-year operating cost forecast dropping by $2.8 billion compared to the GRA financial forecast. At p.16, Mr. Bowman submits that this revised scenario would permit a revised rate path of 2.5% per year for the three test years, followed by 2.83% for the remainder of the forecast.

This scenario resulted from the Consumers Coalition's motion for further and better responses by Manitoba Hydro to information request Coalition/MH-I-27. Manitoba Hydro disputed the motion, in part because it did not deem it appropriate to create scenarios that requested operating and administrative expense increases to be capped at 2% annually, as this would not be a realistic scenario.

Manitoba Hydro's 2024/25 annual report, released on September 26, 2025, discloses that Manitoba Hydro's electric operations incurred a $49 million loss during the fiscal year.

Question:

a) Please elaborate on why Mr. Bowman believes that a 2% scenario for operating costs is realistic, and comment on Manitoba Hydro's position in the motion that indicates it is not realistic.

b) Does Mr. Bowman have a particular view as to which aspects of the operating and administrative costs should be cut to achieve the 2% scenario? In particular, should FTEs be reduced in any particular business area?

c) Does the loss during the 2024/25 fiscal year affect Mr. Bowman's recommendation regarding the appropriate rate path during the rate period? If so, please elaborate.

Rationale for Question:

To better understand how operating costs could be capped at 2%, and the effects of doing so.

Response:

a)

Mr. Bowman has not independently assessed the merits of Hydro's claim that a 2% escalation is unrealistic. However, given the 2% scenario is already materially above (by $50 million to $150 million per year) the scenario Hydro prepared in 2023, the prima facie case that this level of spending is so low as to be unrealistic is unclear.

Indeed, had Hydro solely filed an O&M forecast in this GRA equal to the Coalition/MH-I-27U scenario, it would have indicated a material 11-16% upward shift in the entire O&M cost curve compared to the previous GRA over and above inflation, while still retaining all the same ongoing escalation. Such a scenario would be hard to justify on its own, much less to sustain a case that this is a patently low level of O&M to forecast, as suggested by Hydro.

Operating and Maintenance Costs ($000s)

	Year Ending 2026	2027	2028	2029	2030	2031	2032	2033	2034
2023-25 GRA Scenario	683	697	711	724	736	739	754	769	785
2026-28 2% Cap Scenario (Coal/MH-I-27U)	759	714	789	805	821	853	870	888	905
increase from 2023-25 GRA scenario	*76*	*17*	*78*	*81*	*85*	*114*	*116*	*119*	*120*
	11%	2%	11%	11%	12%	15%	15%	15%	15%

	Year Ending 2035	2036	2037	2038	2039	2040	2041	2042
2023-25 GRA Scenario	800	816	833	849	872	896	914	939
2026-28 2% Cap Scenario (Coal/MH-I-27U)	923	942	961	980	1000	1029	1050	1093
increase from 2023-25 GRA scenario	*123*	*126*	*128*	*131*	*128*	*133*	*136*	*154*
	15%	15%	15%	15%	15%	15%	15%	16%

b)

There is no concept that O&M must be cut to achieve the Coalition/MH-I-27U scenario. Indeed, the O&M can be raised by 11% to 16% above all expectations set out in the 2023-25 GRA.

c)

Only to a limited extent. The loss during the 2024/25 year is largely incorporated into the interest balances and expenses for the financial forecast period. These balances are a component of the scenarios modelled as part of the financial forecast in Appendix 3.1, and the Uncertainty Analysis in Appendix 3.2, which underpin Coalition/MH-I-27U and the remainder of the inputs to the Bowman evidence.

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Part and Chapter:	MIPUG-08 (Bowman Report)	**Page #:**	Appendix A
Topic:	Load Research Report		
Subtopic:	Jurisdictional Scan		

Preamble (if any):

Mr. Bowman provides Appendix A that discusses Manitoba Hydro's previous and current load research methodologies.

Question:

Please provide information on other Canadian electric utilities' choice of load research methodologies and, if possible, confirm the following:

- Which utilities use Manitoba Hydro's previous method (or a variation of this method) and which utilities use Manitoba Hydro's newer method?
- How many hours are used to calculate the coincident peak?
- How many peaks are used to determine cost responsibility?

Rationale for Question:

To understand the prevalence of load research methods.

Response:

Mr. Bowman is aware of no jurisdiction which uses Manitoba Hydro's latest method for preparing load research in a Cost-of-Service study.

The more common approach is to use load characteristics (often from a single year) to establish (a) class non-coincident load factors, and (b) either coincident peak load factors, or coincidence factors, to determine CP shares.

To be clear – Manitoba Hydro uses a 1 CP method for cost allocation, but estimates its 1 CP load shares using historical data based on 50 hours per year (for the previous method) or the synthetically derived peaks (for the new method). Many jurisdictions similarly use 1 CP (a limited number use 3 CP such as Nova Scotia, and previously New Brunswick). However, Mr. Bowman is not aware of any jurisdiction which uses 50 peak hours, or indeed any selection of past non-peak hours, to estimate future coincident peak load shares. The Ontario Energy Board similarly concludes that Manitoba is unusual:

> *Using a one hour (i.e. clock hour) measurement of peak is the most common approach when determining the demand allocator for electricity sector cost allocation studies. A few jurisdictions (for example, Manitoba) use a longer period. It is considered that use of a one hour measurement period of peak, along with the use of the above-mentioned 4 NCP/1 NCP test, will provide an appropriate balance of policy objectives.*[1]

The specific details in each utility's regulatory filings regarding the development of CP load shares is a technical detail that is not always made clear by peer utilities.

Specifically, as examples of those which do provide the needed detail beyond Ontario, Newfoundland Power continues to use the load characteristics from a 2006 load study which looked at 3 years (the single peak hour from each year)[2], while Nova Scotia used a 2022 load research study for their latest COS study to develop hourly load shapes for the purposes of forecast coincident peak share[3] (adjusted to use "peak design" temperatures for weather-sensitive classes). For each peak month, a single hourly value is used.

Mr. Bowman has not rejected the idea that a small number of top hours can be used to help inform the 1 CP forecast. However, 50 hours has been shown to be excessively broad and mutes the key demand signal that is of acute and growing concern.

[1] https://www.oeb.ca/documents/cases/EB-2005-0317/report_directions_290906.pdf, page 63
[2] http://www.pub.nl.ca/applications/NP2025GRA/responses/PUB-NP-104,%202006%20Load%20Research%20Study.PDF
[3] Proceeding M12451, Exhibit N-9, pdf page 1071-1073 of 1738.

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Part and Chapter:	MIPUG-08 (Bowman Report)	**Page #:**	31
Topic:	Resource Planning		
Subtopic:	Changes in the Supply-Demand Balance		

Preamble (if any):

On page 31, Mr. Bowman provides Table 3:

Table 3: Future DSM Contribution to Domestic Loads to 2033/34

	2017-19 GRA	2023-2025 GRA	2026-2028 GRA
source	App 7.3	App 5.6 and MFR 43 (Tab 10)	App 4.3 and MFR 39 (Tab 9)
DSM Contribution To Energy (GW.h)	3,620	2,409	1,809
as a percentage of domestic load	11.00%	8.18%	6.05%
DSM Contribution To Winter peak (MW)	830	664	322
as a percentage of domestic load	13.85%	11.51%	5.58%

Mr. Bowman further states:

> As a result, the decreasing relative DSM contribution to demand has exacerbated anticipated demand shortfalls in future years. This may in part relate to the fact that Efficiency Manitoba's mandate does not include seeking capacity savings, which is an unfortunate omission.

In its Appendix 4.1 (Electric Load Forecast) page 12 of 73, Manitoba Hydro states that its DSM peak forecast has changed because it has more sophisticated modeling of peak savings from DSM programs.

Question:

a) Please confirm whether the Curtailable Rate Program was included as a DSM program in the 2017-19 GRA Appendix 7.3 supply and demand tables. If confirmed, does this explain a portion of the increased DSM as a percentage of domestic load?

b) In terms of the mix of DSM programs, changes in codes and standards, or other changes in the approaches taken by Efficiency Manitoba, please identify the factors Bowman attributes to the decline in winter peak DSM contributions relative to energy DSM contributions. Is Mr. Bowman aware of any DSM programs focused on demand that Manitoba Hydro had as part of its Power Smart Plan that Efficiency Manitoba has not continued?

c) Please explain whether and how Manitoba Hydro's change to its DSM modeling may have influenced the change to relative contributions of DSM programming to winter peak and energy savings.

Rationale for Question:

To understand whether the Curtailable Rate Program is consistently treated in the comparison of supply-demand tables across the three GRAs.

Response:

a)

No. The source for the 2017 -19 GRA was Appendix 7.3, "No New Resources" tables, which note: "Incremental DSM excludes savings already achieved to date, savings achieved through codes and standards which are included in the Load Forecast, and savings from curtailable rates programming beyond existing contracts that do not qualify as winter peak capacity as these are short-term resources."

b)

Mr. Bowman has not done any form of detailed comparison of the programming from 2017 when Manitoba Hydro ran DSM to the Efficiency Manitoba more recent plans.

c)

Mr. Bowman is not aware of any particular factor in regard to how Manitoba Hydro may have done its own DSM modelling as compared to Efficiency Manitoba, but notes that ultimately DSM programming will be assessed in respect of post-project verification such that modelling inaccuracies should become apparent over time, and corrected.

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Part and Chapter:	MIPUG-08 (Bowman Report) 2023 GRA MFR 43 2025 GRA MFR 39	Page #:	34
Topic:	Resource Planning		
Subtopic:	Changes in the Need Date		

Preamble (if any):

On page 34, Mr. Bowman provides Table 6:

Table 6: Supply:Demand Balance and Need Date Changes since 2017-19 GRA

		2017-19 GRA	2023-2025 GRA	2026-2028 GRA
	source	App 7.3	App 5.6 and MFR 43 (Tab 10)	App 4.3 and MFR 39 (Tab 9)
Energy (GW.h)				
	need date	2038/39	2033/34	2031/32
	shortfall in yr 2	728	595	555
	% shortfall in yr 2	2.5%	2.2%	2.0%
Winter peak (MW)				
	need date	2039/40	2030/31	2029/30
	shortfall in yr 2	141	185	615
	% shortfall in yr 2	2.7%	3.6%	11.3%

MFR 43 “No New Resources” from the 2023 GRA has differences from the corresponding Proxy Development Plan in Appendix 5.6. Similarly, MFR 39 “No New Resources” from the current GRA and Appendix 4.3 have differences. MFR 43 and MFR 39 show the Curtailable Rate Program ending in 2027 and 2028, respectively, causing the need date for new resources to advance.

Question:

a) Please provide Mr. Bowman’s views as to whether the Curtailable Rate Program is a “new” resource.

b) Please restate Table 6 reflecting continuation of the CRP throughout the entire period.

c) Please explain whether and how unexplained differences between the power resources in the 2023 GRA “No New Resources” (MFR 43) and the Proxy

Development Plan (Appendix 5.6) such as the additional 100 MW of increased outages from 2030/31 to 2034/35 affect Mr. Bowman's analysis.

d) Please explain whether any of Mr. Bowman's conclusions change if the CRP is continued.

Rationale for Question:

To clarify the treatment of the Curtailable Rate Program and its affect on Mr. Bowman's analysis.

Response:

a)

The Curtailable Rate Program is a capacity offering that requires financial commitment each year in order to continue to secure the benefits. It also requires a customer commitment to accept the lower quality of power that comes with CRP participation.

For this reason, Hydro models the "no new resources" scenarios without the CRP, and then develops its resource plans built on this base, with renewal of the CRP as one of the resources it can elect to include (considering the combined capacity offered and the financial effects of the program). As the program has a very favourable economic profile for Hydro, particularly at the low current compensation rate offered to customers, it is always selected as priority new resource. Further, the program offers other benefits to Hydro beyond peak planning capacity, so the resource is particularly useful.

While this rationale has some underlying logic given the purpose of the "no new resources" baseline analysis, for all other intents and purposes the CRP should be viewed as a long-term and permanent offering of Hydro that customers can rely on into the future.

However, it should also be noted that relying on actual CRP far into the future in this manner also presumes participation in the program, which is not a given. There are few participants in the CRP, and the types of operations that can participate are limited to those that can curtail load on short notice. With the pressures on industrial operations and export markets, whether these customers will continue to operate in Manitoba, or continue to operate at the given load levels, remains quite uncertain. Further, ongoing erosion in the value of the credit provided by Hydro in relation to value, as compared to the challenges posed to the customers from participating, means the future participation should not be immediately assumed.

b)

Each of the years in Table 6 has been represented based on the "no new resources" approach, so each excludes CRP.

To add back CRP, assuming it is a permanent offering, it is necessarily to include only Option A. The other CRP options are not considered planning capacity, as they serve other purposes.

It is Mr. Bowman's understanding that since the elimination of Option C in 2016, the program has had the same 225 MW of participation, with 50 MW under Option R (see, for example, Appendix 9.12 in the 2017 GRA, and Appendix 7.15 in the current GRA). This leaves 175 MW for Option A, which must then be decreased to some degree due to customer on-peak load and coincidence factors. For this reason, the available capacity from the CRP program will remain fairly constant throughout the three scenarios, but will not be exactly the same.

Values of the ongoing CRP resources are available for the 2025 GRA (151 MW) and 2023 GRA (162 MW), but do not appear to have been provided for the 2017 GRA, so 162 MW has been assumed in preparing the revised Table 6 below:

Revised Table 6 Assuming CRP is Continued Throughout Horizon

		2017-19 GRA	2023-2025 GRA	2026-2028 GRA
	source	App 7.3	App 5.6 and MFR 43 (Tab 10)	App 4.3 and MFR 39 (Tab 9)
Energy (GW.h)				
	need date	2038/39	2033/34	2031/32
	shortfall in yr 2	728	595	555
	% shortfall in yr 2	2.5%	2.2%	2.0%
Winter peak (MW)				
	need date	2041/42	2031/32	2030/31
	shortfall in yr 2	239	104	527
	% shortfall in yr 2	3.4%	1.9%	9.9%

As noted in Revised Table 6 above, the continuation of the CRP can delay the need date for capacity (by 1 to 2 years) but does not change that capacity has become a much more significant driver of the next resource need, both sooner and in larger quantities than in previous forecasts.

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Part and Chapter:	MIPUG-08 (Bowman Report) Q1 2025/26 Financial Report	**Page #:**	38 5
Topic:	COSS		
Subtopic:	Impact of Net Export Revenue		

Preamble (if any):

On page 38, Mr. Bowman states:

> **Water Conditions:** The PCOSS inputs have seen a dramatic change in water conditions from PCOSS24 (extreme high water) to PCOSS26 (low reservoirs). While there has been past analysis conducted to indicate the effect of "normalizing" these conditions44, Hydro's methods remain focused on preparing a PCOSS that accurately represents the expected conditions in the year being modelled. This is appropriate. It should be noted that Hydro's approach can drive variances in the PCOSS outputs (the Revenue:Cost Coverage ratios per class, or "RCCs"), leading to somewhat higher RCC values for Residential during low water (like PCOSS26) and somewhat lower RCC values for industrials (and vice versa for high water). Nonetheless, PCOSS26 reports the expected conditions in the year in question and it remains sound to use projected conditions, as Hydro has done.

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 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.

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)

In respect of PCOSS26, it is noted that the inputs are based on the Financial Forecast scenario set out in Appendix 3.1, which forecasts a $218 million net income for 2025/26. The latest updates now project a net loss for 2025/26. This change could have an impact on the PCOSS analysis. However, as the PCOSS is prepared based on ratios, not absolute values, the question is whether the change is likely to be sufficiently (a) material and (b) disproportionate across the classes to change the conclusions relied upon.

Mr. Bowman does not expect this effect to make a material revision to the conclusions regarding the relative RCC ratios, for three reasons:

i. The change in net income has been cited that it “could fall within the range seen over the last two fiscal years” which remains highly speculative. These values have not been incorporated into financial forecasts that feed into the PCOSS. Without a specific value, assume the ultimate net income would arise at negative $100M, approximately a $300M change from the forecast underlying PCOSS26.

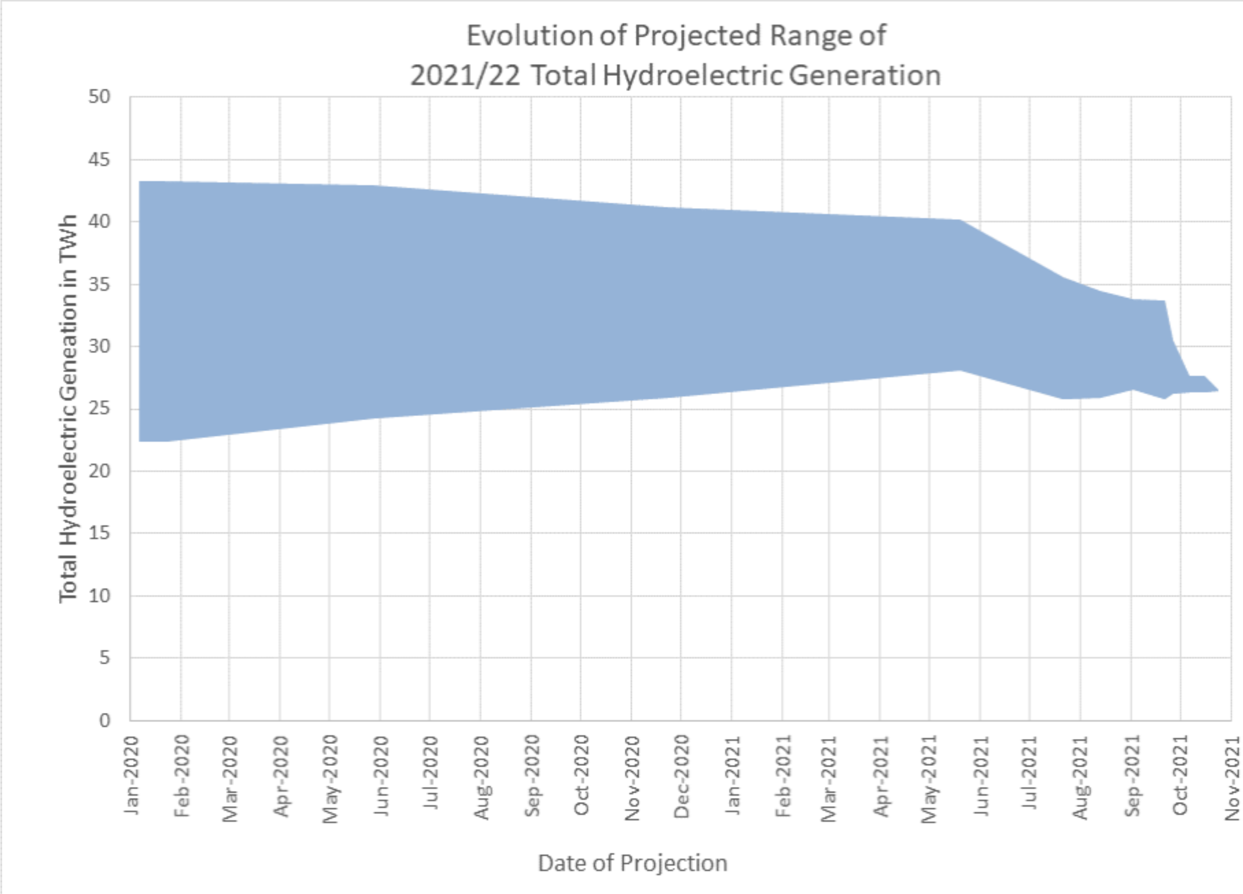
   We do not have a precise analysis from this GRA, but there is information available from the previous GRA to give an indication of the effect of this magnitude of change. In that case, the change was approximately $200 million directly to net export revenues, comparing PCOSS24 to PUB/MH-I-141a, which led to no difference in which classes were within and which were outside the ZOR. Assuming this change was all from items that operate similar to export revenue, the same conclusion is expected – i.e., none of the classes that are above the ZOR in PCOSS26 would be expected to move into the ZOR.

ii. The changes that led to the decrease in net income are cited in the 1st Quarter report as being widespread and linking significantly to O&M and not solely export revenues. The export revenue decline was cited as being driven in part by the “need to responsibly manage water to ensure reliable operations for the remainder of the year” which suggests some future offsets (Q2-Q4) may be included in the export revenues component of the impact. However, the increased net loss is also driven by O&M: “Operating and administrative expenses increased primarily due to higher materials & tools costs, overtime largely necessitated by wildfire support and restoration activities, higher employee benefits costs and a reduction in labour hours charged to capital projects.” This type of effect would have potentially no net effect on the RCC ratios in the PCOSS as O&M affects all functions equally.

iii. The focus of the recommendations for differential rate impacts is based on targeting resolution of the long-standing RCC issues over three years. The latest updates indicate that in future test years, the net income and export revenues are now higher than forecast in the GRA financial scenarios, due to “an increase in the forecasted on- and off-peak energy prices” (PUB/MH-I-7a-d). With a focus on acceptable ZOR outcomes 3 years in the future, when average water conditions should be assumed (and increased export prices are now also assumed), the reason for the recommendations remain fully valid.

If there is a net effect on the overall Bowman recommendations from the updated financial scenario, it would be to the overall average rate increase recommendations, which may see some upward pressure compared to the original financial scenario. However, this effect would be limited, and there remains a significant basis for concern that the O&M projected in the financial forecast (including the scenario in Coalition/MH-I-27U Scenario #3), along with increased assumptions about export prices, are more than able to absorb any one-time effects from variations in the 2025/26 water flow projections.

It is also important to note that further water flow information should become available to the Board as the proceeding advances. Consider the figure produced by Hydro in the 2021 IRA (Figure 10) which shows how the evolution of time narrows the projected hydroelectric generation expectations. The Q1 report was based on information to June 30, when a high degree of variability is still present in forecasts (likely equivalent to the blue range shown for June 2021, for the 2021/22 forecasts in the figure below). Updated hydroelectric generation figures did not become tightened until November 2021 for that fiscal year, and similarly the Board and all parties should be able to secure updated water flow scenario information from Hydro prior to the completion of the current GRA. At that time, it can be determined if a revised overall rate increase proposal is needed. However, for all the reasons set out above, it remains unlikely that a revised differential rate proposal will be required.


Evolution of Projected Range of
2021/22 Total Hydroelectric Generation
Total Hydroelectric Geneation in TWh
50
45
40
35
30
25
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15
10
5
0
Jan-2020
Feb-2020
Mar-2020
Apr-2020
May-2020
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Nov-2021
Date of Projection

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Part and Chapter:	MIPUG-08	Page #:	39-42
Topic:	Wind Generation – Classification		
Subtopic			

Preamble (if any):

Beginning at p. 39, Mr. Bowman reviews the history behind Manitoba Hydro's classification of wind at 100% energy. Mr. Bowman goes on to state that the reasoning behind this is no longer consistent with the factual basis facing Manitoba Hydro. This is because Manitoba Hydro has specifically stated that wind generation yields capacity value, that the Supply and Demand table used for resource planning continue to attribute a material capacity value to existing wind, and Manitoba Hydro shows an increasing reliance on purchases of wind generation as capacity.

As a result, Mr. Bowman makes the following recommendation at p. 42:

> RECOMMENDATION 3: Eliminate the special Cost of Service classification treatment for wind generation, and treat the wind costs the same as all other power supply costs, classified to demand and energy at the System Load Factor

Question:

Please explain whether Mr. Bowman is aware of the best practices and approaches used by similar utilities with respect to the classification of wind for cost of services purposes.

Rationale for Question:

To better understand how other utilities are approaching the classification of wind generation.

Response:

The latest update Mr. Bowman is aware of is in Nova Scotia, where the utility NS Power has filed a new GRA with updated cost of service methods, and has negotiated with customers leading to support from all major customer groups of the methods related to generation. The approach is to classify all generation rate base and OM&A by the system load factor. (NS Energy Board proceeding M12451, Appendix 12B Page 22-23)[4]. NS Power has also filed the evidence of Elenchus in support of their proposal, which notes:

> *The system load factor method is a simple and pragmatic approach to classifying costs that are functionalized as generation costs as energy- and demand-related in a manner that ignores the cost difference across NS Power's various supply resources reflecting factors such as vintage and current operational considerations. It instead classifies and allocates the*

[4] When downloaded from the NS Energy Board website, it is exhibit N-9, pdf page 1680 of 1738.

> *total fixed costs of the supply resources based on the overall requirement for capacity and energy as evidenced by class-specific energy and capacity requirements. (same reference, page 24).*

Page 26 of the document also notes that wind purchases are classified by System Load Factor. Elenchus also produced a survey of major Canadian utilities and Generation classification ratios, which is at Appendix 12(a) page 14 of 18, reproduced below.[5] As noted in the Table, Manitoba Hydro is the only utility in he survey that uses 100% energy as the classification for wind (note that the survey records the previous NS Power methods, not the updated negotiated approaches).

[5] Pdf page 1617 of 1780

Table 1 – Assets & Depreciation and OM&A Classification

Utility	System Load Factor Basis	Assets and Depreciation	OM&A
BC Hydro	N/A	55% demand / 45% energy	
SaskPower	1CP	System load factor 25% demand / 75% energy	
Manitoba Hydro	1CP	Eight-year average system load factor 39.3% demand / 60.7% energy - Except wind 100% energy	Eight-year average system load factor 39.3% demand / 60.7% energy - Except variable hydraulic O&M 100% energy
Hydro Quebec	1CP	35.0% demand / 65% energy	
NB Power	1CP*	Peak and average methodology 50.4% energy / 49.6% demand	
Nova Scotia Power	1CP	Hydro and Steam is based on system load factor - overall 46.3% demand / 53.7% energy. Other generation is 100% demand. Environmental & fuel conversion costs classified 100% energy.	
Maritime Electric	N/A	Point Lepreau - judgement based on analysis of various classification methodologies (25% demand/75% energy). On island generation is 100% demand. Wind is 23% demand based on capacity used for planning purposes.	Blended allocator based on classifications of assets. Weighted average is 72% demand / 28% energy.
Newfoundland Power	1CP	System load factor (45.7% demand / 54.3% energy) for hydro assets. Other generation is 100% demand.	System load factor 45.7% demand / 54.3% energy for hydro assets. Other generation is 100% demand.

* NB Power currently uses a 3CP but was ordered to replace the 3CP with a 1CP. NB Power has not yet filed an updated study with this method.

The above table does not include Newfoundland Hydro, which also classifies wind with a capacity component (22% demand).[6]

[6] http://www.pub.nl.ca/applications/2018/NLH2018CostofService/settlement/Settlement%20Agreement%20-%202019-10-04.PDF Item 25.

For very small utilities where wind plays solely a function of displacing fuel costs (such as in Inuvik (Northwest Territories Power Corporation) or Whitehorse (Yukon Energy)) wind remains typically classified 100% to energy.

PUB/MIPUG I-8

Part and Chapter:	MIPUG-08 (Bowman Report)	**Page #:**	48
Topic:	COSS		
Subtopic:	Class Peak Demand Contribution		

Preamble (if any):

On page 48, Mr. Bowman states:

> The basic factual situation is not different for an electrical utility. The system must be designed to take into account the extreme peak loads that it may experience (e.g., a P90 peak, or a P99), and the drivers of these extreme peaks are weather, and the weather-dependent classes. For this reason, Centra has already adopted a CP measure which shows the class specific contribution not at average weather, but at design peak conditions.

Question:

Please confirm whether Centra’s coincident peak is based on a peak day or a peak hour, and explain whether this has any bearing on the number of hours that should be used by Manitoba Hydro to determine its coincident peak.

Rationale for Question:

To compare the class peak demand methodologies between Manitoba Hydro and Centra.

Response:

Centra Gas Manitoba considers the peak day when determining its coincident peak using a theoretical design day based on a design day temperature. However, differences between gas and electric utilities also account for part of this difference, as gas utilities have some buffering capability that is not present for electric utilities.

This difference is not likely of significance to considering the number of hours Manitoba Hydro should use to capture its forecast peak.

PUB/MIPUG I-9

Part and Chapter:	MIPUG-08 (Bowman Report)	Page #:	54
Topic:	Rate Differentiation		
Subtopic:			

Preamble (if any):

On page 54, Mr. Bowman states:

Table 14: RCC Changes Arising from 3.5%/0% Rate Change Scenario

	PCOSS26	Scenario Yr 1	Scenario Yr 2	Scenario Yr 3
Residential	96.9%	97.8%	98.7%	99.6%
GS Small ND	108.0%	105.5%	103.0%	100.6%
GS Small - D	96.0%	96.8%	97.6%	98.4%
GS Medium	97.8%	98.6%	99.3%	100.1%
GSL 0-30 kV	100.9%	101.5%	102.2%	102.8%
GSL 30-100 kV	110.4%	107.2%	104.0%	100.9%
GSL >100 kV	110.6%	107.3%	104.0%	100.8%
ARL	104.2%	106.1%	108.0%	109.9%

Question:

Assuming the Board accepted Bowman's recommended rate differentiation but not the overall increase of 2.5%, please calculate the rate differentiation needed to achieve the same (or similar) RCCs as in Table 14 but with 3.5% rate increases for all classes.

Rationale for Question:

To understand Mr. Bowman's recommended rate differentiation.

Response:

If the average rate increase for all classes were adjusted to 3.5% rather than 2.5% proposed by Mr. Bowman, the remainder of the rates proposed would similarly increase by very close to 1% to yield the approximate same RCC ratios – i.e., average increases of 4.5% for the classes below or within the ZOR, and 1.0% for those above the ZOR. This is because the added rate revenue would arise as net income in the PCOSS, which is largely shared across all functions.

It should also be noted that the above data for Scenario Yr 3 is not the results of PCOSS28, it is simply a revised PCOSS26 with rebalanced rates. A true PCOSS28 would likely have a return to normal water, and also build in the projected other changes, such as higher on-peak and off-peak prices, and lower contracted volumes, as is included in the financial forecast for 2027/28. These values have not yet been modelled by Hydro, and therefore within the range of precision represented by Yr 3, there is likely little net impact of adjusting all rates upward by 1% on the overall RCC targets.

PUB/MIPUG I-10

Part and Chapter:	MIPUG-08 (Bowman Report) 2017/18 GRA Coalition/MH I-119	**Page #:**	57
Topic:	Rate Rebalancing		
Subtopic:	GSL Rate Rebalancing		

Preamble (if any):

On page 57, Mr. Bowman states:

> **RECOMMENDATION 7:** The firm rates for each of the GS Large classes should be rebalanced on a revenue-neutral basis, such that demand cost recovery is increased by 2 percentage points (as a percentage of overall class revenues) and energy rates reduced by an equal and offsetting dollar amount.

In response to Coalition/MH I-119 from the 2017/18 & 2018/19 GRA, Manitoba Hydro previously expressed rate design guidelines:

> For General Service customer, no customer will experience an increase in their average monthly bill over a year which exceeds the greater of $5.00 per month or five percentage points more than the class average increase.

Question:

a) Please calculate the range of bill impacts (assuming an overall class revenue increase of 0%) due to the recommended rate rebalancing for customers in each GSL class using the representative consumptions in Appendix 7.10.

b) Please provide Mr. Bowman's view on whether rate design changes should be limited such that no General Service customers experience an average monthly bill increase greater than 5% more than the class average increase.

Rationale for Question:

To understand the bill impacts that may arise from rate design changes to the GSL classes.

Response:

a)

Based on the proof of revenue (MFR 84 Excel version), the rates arising from the proposed rebalancing are as follows:

GENERAL SERVICE	2025/26 Billing Determinants	Approved Rates Effective April 1, 2024	Revenue at Approved Rate April 1, 2024	Proposed Rates Effective Jan 1, 2026	$ -
Large 750V-30kV	4,578		$ -		$ -
Energy Charge per kWh	1,933,248,062	$0.04219	$ 81,563,736	$0.04085	$ 78,966,983
Monthly Demand Charge per kVA	4,664,143	$10.35	$ 48,273,882	$10.91	$ 50,870,634
			$ 129,837,618		$ 129,837,618
LUBD Lrg 750V-30kV	68		$ -		$ -
Energy Charge per kWh	2,383,280	$0.10063	$ 239,829	$0.09785	$ 233,210
Monthly Demand Charge per kVA	36,452	$2.50	$ 91,131	$2.68	$ 97,750
			$ 330,960		$ 330,960
Large 30-100 kV	582		$ -		$ -
Energy Charge per kWh	2,099,250,897	$0.03882	$ 81,492,920	$0.03771	$ 79,161,409
Monthly Demand Charge per kVA	4,065,193	$8.63	$ 35,082,616	$9.20	$ 37,414,127
			$ 116,575,536		$ 116,575,536
LUBD Large 30-100 kV					$ -
Energy Charge per kWh		$0.08734	$ -	N/A	$ -
Monthly Demand Charge per kVA		$2.09	$ -	N/A	$ -
					$ -
Large >100 kV	238		$ -		$ -
Energy Charge per kWh	3,552,149,948	$0.03766	$ 133,773,967	$0.03663	$ 130,098,078
Monthly Demand Charge per kVA	6,479,337	$7.72	$ 50,020,481	$8.29	$ 53,696,370
			$ 183,794,448		$ 183,794,448
LUBD Lrg >100 kV	38		$ -		$ -
Energy Charge per kWh	1,335,387	$0.08094	$ 108,086	$0.07840	$ 104,688
Monthly Demand Charge per kVA	33,243	$1.86	$ 61,833	$1.96	$ 65,231
			$ 169,919		$ 169,919

This approach raises demand charges by 2% of overall revenue in the first year, with reductions in the energy portion of the bill. The resulting rate impacts for the customers shown in Appendix 7.10 are as follows (based on 730 hours in a month):

Category	Load Factor	Demand	Customer Bill (Apr 2024)	Customer Bill (Jan 2026)	Change in Monthly Bill ($)	Percentage Increase
General Service Large - 750 V to 30 kV	25%	5,000 kVA	90,248	91,826	1,578	2%
General Service Large - 750 V to 30 kV	50%	5,000 kVA	128,747	129,101	354	0%
General Service Large - 750 V to 30 kV	75%	5,000 kVA	167,245	166,377	(868)	-1%
General Service Large - 750 V to 30 kV	100%	5,000 kVA	205,744	203,653	(2,092)	-1%
General Service Large - 30 kV to 100 kV	25%	10,000 kVA	157,147	160,821	3,674	2%
General Service Large - 30 kV to 100 kV	50%	10,000 kVA	227,993	229,642	1,649	1%
General Service Large - 30 kV to 100 kV	75%	10,000 kVA	298,840	298,462	(378)	0%
General Service Large - 30 kV to 100 kV	100%	10,000 kVA	369,686	367,283	(2,403)	-1%
General Service Large - Over 100 kV	25%	50,000 kVA	729,648	748,749	19,101	3%
General Service Large - Over 100 kV	50%	50,000 kVA	1,073,295	1,082,998	9,703	1%
General Service Large - Over 100 kV	75%	50,000 kVA	1,416,943	1,417,246	303	0%
General Service Large - Over 100 kV	100%	50,000 kVA	1,760,590	1,751,495	(9,095)	-1%

b)

No customer represented in Appendix 7.10 would see a bill increase more than 5% above the average for the class.

PUB/MIPUG I-11

Part and Chapter:	MPIUG-08	**Page #:**	56-58
Topic:	Industrial Customer Rate Design		
Subtopic			

Preamble (if any):

Beginning at p. 56, Mr. Bowman states that the design of demand and energy rates for industrial customers is not directly aligned with the embedded costs. This leads to him make the following recommendation at p. 57:

> RECOMMENDATION 7: The firm rates for each of the GS Large classes should be rebalanced on a revenue-neutral basis, such that demand cost recovery is increased by 2 percentage points (as a percentage of overall class revenues) and energy rates reduced by an equal and offsetting dollar amount.

Question:

Does MIPUG have any indication on the range of increases and decreases that would be faced by customers in that class if the Board were to adopt this proposal.

Rationale for Question:

To better understand the effect of Mr. Bowman's recommendation on different customers within the industrial class.

Response:

Mr. Bowman does not have specific loads and bills for individual customers, but the template impacts are set out in PUB/MIPUG-I-10 for customers of varying load factors.

PUB/MIPUG I-12

Part and Chapter:	MIPUG-08 (Bowman Report)	Page #:	60
Topic:	Rate Design and Rebalancing		
Subtopic:	Residential Rate Design Changes		

Preamble (if any):

On page 60, Mr. Bowman states:

> **RECOMMENDATION 8:** Hydro's residential rate design excessively recovers costs from summer energy. Efforts should be made to increase cost recovery using other tools, such as increases in basic customer charges, seasonal rates based on higher winter energy charges than summer, or second block rates which charge higher prices for larger use in a month. These measures do not require waiting for AMI to be installed.

Question:

a) Please confirm whether Mr. Bowman is aware of any other Canadian jurisdiction where residential ratepayers pay a higher seasonal rate. If so, please confirm whether there are any affordability measures tied to such a rate.

b) Please explain whether or how it would be possible to avoid unacceptable bill impacts for space heating customers with higher winter energy rates.

c) Please provide a listing of major Canadian utilities that have a residential inclining block rate (e.g., BC Hydro and Fortis) and where the cutoff is for each block.

Rationale for Question:

To understand the implications of higher winter energy rates for residential customers.

Response:

a)

Please see GSS-GSM/MIPUG-I-1(b). As the current rate offerings identified are all optional rates, there is no identified affordability measures known to be in place.

b)

Avoiding unacceptable bill impacts for space heating customers would be avoided by implementing any changes with an eye to other rate design criteria such as gradualism. At this time, no Canadian jurisdiction has directly addressed seasonal rate variation for all customers, though New Brunswick has been directed to pursue such measures. It is assumed any introduction of the concept would only occur with an eye to rate impacts that arise.

However, it should also be noted that customer who heat with any other source (e.g., natural gas, wood, propane) are directly exposed to their heating fuel price variability tied to market prices, and as such it may be inappropriate to overweight consideration of rate stability for heating with electricity.

c)

Major Canadian utilities with residential inclining block structures include the following:

Utility	**Cut-Off (Monthly)**
OEB (Residential Tiered)[7]	600 kW.h (summer) 1000 kW.h (winter)
Hydro Quebec (Rate D)[8]	40 kW.h * days in consumption period
BC Hydro (Residential Tiered)[9]	675 kW.h
Yukon Energy (Residential Non-Government)[10]	1000 kW.h and 2500 kW.h

[7] https://www.oeb.ca/consumer-information-and-protection/electricity-rates
[8] https://www.hydroquebec.com/data/documents-donnees/pdf/electricity-rates.pdf
[9] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/tariff-filings/electric-tariff/bchydro-electric-tariff.pdf
[10] https://yukonenergy.ca/media/site_documents/1038_1160%20Residential%20Service%20Hydro,%20Non-Government.pdf

PUB/MIPUG I-13

Part and Chapter:	MIPUG-09 (Friesen Report) MFR 84	**Page #:**	9, 19 of 58
Topic:	Rate Differentiation		
Subtopic:	Recommended Rate Increases		

Preamble (if any):

On page 9, Mr. Friesen states:

> It is requested that the Board:
>
> - Approve differentiated component rate increases for the GSL rate classes

On page 19, Mr. Friesen states:

> Table 2.4 provides an illustrative example showing the results of a 3.5% annual increase to GSL demand component rates with a corresponding 3.5% decrease to energy component rates over a three-year period, including a five-year projection to 2030. Table 2.5 provides indication of how alignment with rates based on embedded costs improves for both demand and energy over that time.

In MFR 84, Manitoba Hydro provided a spreadsheet of rates and billing determinants.

Question:

a) Please provide the specific rate differentiation requested by Mr. Friesen, or the basis for calculating the rate differentiation. Is the recommended differentiation to increase GSL demand rates by 3.5% and decrease energy rates by 3.5%?

b) Please calculate the percentage changes in total class revenues for GSL classes resulting from the recommended rate component differentiation.

Rationale for Question:

To clarify the requested rate differentiation.

Response:

a)

Mr. Friesen did not provide a specific rate differentiation recommendation in evidence.

The illustrative example of a 3.5% increase in demand component rates and opposing 3.5% decrease in energy component rates was indicative of the type of actions that would be required to correct the current demand and energy component cost/revenue imbalance over a period of five years for the two higher voltage GSL subclasses. As the illustrative case demonstrated, this approach would not achieve balance within the lower voltage, 750 V – 30 kV rate structure. Achieving that same balance would require 5 years of 7.0% annual demand rate increases and 4.5% annual energy rate decreases (see table below).

Demand Rate	Rate Change 5.25%	Embedded Rate PCOSS26	Approved Rate 01-Apr-24	Proposed Rate 01-Jan-26	Proposed Rate 01-Jan-27	Proposed Rate 01-Jan-28	Proposed Rate 01-Jan-30
GSL <30 kV	7.00%	14.81	10.35	11.07	11.85	12.68	14.52
GSL 30 - 100 kV	3.50%	10.39	8.63	8.93	9.24	9.57	10.25
GSL >100 kV	3.50%	9.28	7.72	7.99	8.27	8.56	9.17

Demand Rate	Approved Rate - Yr 0 01-Apr-24	Proposed Rate - Yr 1 01-Jan-26	Proposed Rate - Yr 2 01-Jan-27	Proposed Rate - Yr 3 01-Jan-28	Proposed Rate - Yr 5 01-Jan-30
GSL <30 kV	69.9%	74.8%	80.0%	85.6%	98.0%
GSL 30 - 100 kV	83.1%	86.0%	89.0%	92.1%	98.6%
GSL >100 kV	83.2%	86.1%	89.1%	92.2%	98.8%

Energy Rate	Rate Change -4.00%	Embedded Rate PCOSS26	Approved Rate 01-Apr-24	Proposed Rate 01-Jan-26	Proposed Rate 01-Jan-27	Proposed Rate 01-Jan-28	Proposed Rate 01-Jan-30
GSL <30 kV	-4.50%	0.03250	0.04219	0.04029	0.03848	0.03675	0.03351
GSL 30 - 100 kV	-3.50%	0.03140	0.03882	0.03746	0.03615	0.03488	0.03249
GSL >100 kV	-3.50%	0.03100	0.03766	0.03634	0.03507	0.03384	0.03151

Energy Rate	Approved Rate 01-Apr-24	Proposed Rate 01-Jan-26	Proposed Rate 01-Jan-27	Proposed Rate 01-Jan-28	Proposed Rate - Yr 5 01-Jan-30
GSL <30 kV	129.8%	124.0%	118.4%	113.1%	103.1%
GSL 30 - 100 kV	123.6%	119.3%	115.1%	111.1%	103.5%
GSL >100 kV	121.5%	117.2%	113.1%	109.2%	101.7%

b)

The illustrative example in a) has the following annual revenue impacts for offsetting 3.5% demand (increases) and energy (decreases) for the three GSL subclasses.

	Determinants - Table A2		Table A1	Approved Rates		2026 - 2028 GRA								Year 5 Projection	
GSL Rate	Annual Demand (MVA)	Annual Energy (MWh)	Embedded Cost ($M)	Approved 1-Apr-24 ($M)	(% emb)	Annual Rate Increase Demand (%)	Energy (% emb)	Proposed 1-Jan-26 ($M)	(% emb)	Proposed 1-Jan-27 ($M)	(% emb)	Proposed 1-Jan-28 ($M)	(% emb)	Proposed 1-Jan-28 ($M)	(% emb)
GSL <30 kV	4,701	1,935,631	132.5	130.3	98.3%	7.00%	-4.50%	130.1	98.1%	130.2	98.2%	130.7	98.6%	133.1	100.4%
GSL 30 - 100 kV	4,065	2,099,251	108.2	116.6	107.8%	3.50%	-3.50%	114.9	106.3%	113.5	104.9%	112.1	103.7%	109.9	101.6%
GSL >100 kV	6,513	3,553,485	170.6	184.1	107.9%	3.50%	-3.50%	181.2	106.2%	178.5	104.6%	176.0	103.2%	171.7	100.6%

Demand Rate	5.25%	Avg Increase
Energy Rate	-4.00%	Avg Increase

PUB/MIPUG I-14

Part and Chapter:	MIPUG-09 (Friesen Report)	**Page #:**	22 of 58
Topic:	Billing Demand Definition		
Subtopic:	Changes required to implement change in billing demand definition		

Preamble (if any):

On page 22, Mr. Friesen recommends:

- That the change in Definition to Billing Demand, with any alterations approved in this proceeding, be applied to GSL 750 V – 30 kV customers with interval metering.

Question:

a) Please confirm whether the recommendation to change the definition for billing demand means there would be two distinct definitions of billing demand for the GSL 0-30 kV class.

b) Please confirm whether the recommendation to change the definition for billing demand would require an increase to the demand rate for interval metered customers to account for the reduction in demand billing determinants, if this change was expected to be revenue neutral to Manitoba Hydro.

Rationale for Question:

To understand the implications of the recommended change.

Response:

a)

The recommendation to change the definition for billing demand requires interval metering data to validate the date and time of the peak demand in the on-peak and off-peak hours within each billing period.

Based on the Load Research Report [Appendix 4.2, Table 1.1 – Population Statistics, PDF p. 6], 135 of the 371 customers in the GSL 750 V – 30 kV subclass absent of interval metering would therefore be ineligible for adoption of this recommendation, resulting in two distinct definitions for billing demand for the GSL lower voltage subclass.

Comparison to the Analysis of GSL 750 V – 30 kV Subclass [Appendix 7.3, PDF p. 3] indicate that customers eligible for adoption this recommendation may vary from 224 (65.7% per Appendix 7.3) to 236 (63.6% per Appendix 4.2).

See Table G4/G5 [Appendix 7.1]

b)

As noted in Mr. Friesen's evidence, the concept of making this change on a revenue neutral basis appears counter-intuitive to the stated objective of encouraging customers to reduce their coincident peak demand and thereby reduce the capacity requirements on the electric grid.

Examining the data provided in response to MIPUG/MH II-15 provides an understanding of the experience with implementation of the change in the Definition for Billing Demand in the GSL 30 – 100 kV and GSL >100 kV subclasses.

i) The 0.5% annual rate increase approved for the two higher voltage GSL subclasses effective April 1, 2024, materialized as a demand only increase of 2.74% and 2.93% respectively for the GSL 30 – 100 kV and GSL >100 kV subclasses. A similar 0.5% annual rate increase approved for these subclasses effective September 1, 2023, resulted in a demand only increase of 1.69% and 1.90%.

   The additional requirement for a revenue neutrality adjustment effective April 1, 2024, increased demand charges by approximately 1.0% as requested by Manitoba Hydro in its Application.

ii) As expected, half of the 66 customers in these two higher voltage GSL rate classes saw an effective increase in their demand bill in 2024/25 despite seeing a reduction in their total billing demand. This outcome is challenging for many customers given the limited opportunities for offsetting the additional 1% revenue neutrality adjustment to demand charges.

   The noted outcomes seem unnecessary given that these customers are already subject to RCC ratios that exceed 110%, well above the Board approved 95% - 105% ZOR, while demonstrating consistent consumption behavior that is already beneficial to the capacity requirements for the electric system.

PUB/MIPUG I-15

Part and Chapter:	MIPUG-09 (Friesen Report)	**Page #:**	28 of 58
Topic:	Billing Demand Definition		
Subtopic:	Customer Response		

Preamble (if any):

On page 28, Mr. Friesen states:

> This response is the most profitable response under most scenarios. Maintaining on-peak demand at existing levels protects against costly production losses. Increasing demand to the limit of the cap during the off-peak hours allows for additional production. A perfect scenario allows for a 6.5% increase in energy consumption and related production. Energy accounts for 60% (0.4 Lf) to 75% (0.9 Lf) of a customer's total monthly energy bill. Increasing energy consumption by 6.5% will increase a customer's total energy bill by 3.9% - 4.9%. Again, one hour of variability in the off-peak hours could increase the demand bill and result in a loss of all or a portion of the demand charge offset.

Question:

Please explain whether electricity makes up a substantial enough portion of an industrial customer's costs that the change in billing demand provides enough incentive to increase total production (i.e. no change in on-peak production but increased off-peak production) that would otherwise not have been increased absent the billing demand definition change.

Rationale for Question:

To understand the customer response to the change in billing demand definition.

Response:

Industrial customers generally seek to optimize all cost-effective opportunities to lower per unit production costs that are reasonably within their control. Market demand and competitiveness are primary factors for establishing targeted levels of production output.

Based on experience, the proportional share of electricity costs relative to total costs will vary considerably by industry sector, ranging from a low of 10% to a high of 70%. It would be reasonable to suggest that there is a greater concentration of industrials in the range of 15% - 25%. The proportional share of demand costs will vary based on the design of the rate structure and load factor. Under Manitoba Hydro's current GSL rate structure, demand costs typically account for about 22% - 45% of total electricity rate charges, with lower load factor customers having a higher share of demand costs. Irrespective of the above noted share of demand costs, electricity costs generally, and demand costs specifically, still represent a significant cost for larger industrial customers.

Other factors, such as market demand and available off-peak production capacity are also likely to influence actions to increase production capacity in off-peak periods. As noted in evidence, a single interval event could wipe a portion of the expected demand savings available under the revised Definition for Billing Demand.

PUB/MIPUG I-16

Part and Chapter:	MIPUG-09 (Friesen Report)	**Page #:**	29 of 58
Topic:	Billing Demand Definition		
Subtopic:	Results of the Change in Billing Demand Definition		

Preamble (if any):

On pdf page 29, Mr. Friesen states:

> The responses to PUB/MH I-76 and MIPUG/MH II-15 showed that the change to the definition did result in an average 1.0% reduction in billable demand during the first year of implementation. Unfortunately, any bill savings that may have occurred from this measure were offset by the approved 1% increase in demand charges.
>
> This result appears punitive when two key factors are considered:
>
> • GSL customers in the impacted subclasses already pay rates that are 110% higher than embedded cost allocations. Efforts to reduce rates, in the form of differentiated rate increases, have not provided a material change in RCC ratios that are well above the 95% - 105% ZOR.

On page 32 of Tab 8 from the 2023/24 GRA, Manitoba Hydro states:

> An analysis of the hourly loads for customers served at voltages > 30 kV show that the proposed change in billing demand definition will reduce the demand billing determinant to approximately 99% of billing demand under the current definition. Manitoba Hydro is proposing a slight increase to the demand charge to ensure the full revenue requirement continues to be recovered and maintain revenue neutrality for the classes. For most customers, the increase in the demand charge will be offset by the reduction in their measured billing demand resulting in negligible bill impacts.

Question:

a) Please confirm or otherwise explain whether the results of the billing demand definition change were in line with the expectations as laid out by Manitoba Hydro at the 2023/24 GRA.

b) Please calculate the cumulative rate increases to date for Residential, GSL 30-100 kV, and GSL >100 kV customers beginning with the differentiated rate increases approved in Order 68/18.

c) Please calculate the RCC ratios for the Residential, GSL 30-100 kV, and GSL >100 kV classes had across-the-board rate increases instead of the differentiated rates been approved by the Board in Orders 68/19, 140/21, and 104/23.

Rationale for Question:

To clarify the expected results of the change in billing demand definition.

Response:

a)

When queried by both the Coalition and MIPUG [MIPUG/MH I-24a] regarding its expectations, Manitoba Hydro spoke to the disconnect between the way costs were allocated to customers compared to how costs were recovered. The response indicated that the change to the definition of billing demand provided a more refined price signal [Coalition/MH I-157a, PDF p. 859].

- These statements correlate with the position taken by Manitoba Hydro during the 2023/24 GRA. [Appendix 8, Section 8.8.2, PDF p. 31]

The 2023/24 Application requested a revenue neutral adjustment to ensure that the full revenue requirement continued to be recovered. Manitoba Hydro stated that “for most customers, the increase in the demand charge will be offset by the reduction in their measured billing demand resulting in negligible bill impacts” [Appendix 8, Section 8.8.2, PDF p. 32].

- The response to PUB/MIPUG I-14 indicates that half of the impacted GSL customers experienced increases that were not offset by reductions in their measured billing demand due to the revenue neutral adjustment.

Responses to MIPUG/MH I-24a and Coalition/MH I-157a indicate that Manitoba Hydro did not expect the change in definition to result in a material change to the existing load shape or load shifting, while suggesting that there was a greater opportunity for customers to manage their energy bills that was not available under the existing rate construct. [PDF p. 859] Responses to MIPUG/MH I-111b from the 2023/24 GRA also shared these perspectives. [PDF p. 500] Responses to MIPUG/MH I-110a in the 2023/24 GRA revealed concerns about the “need to avoid potential unintended consequences to Manitoba Hydro’s system and/or costs, of unchecked load growth in hours defined as non-peak, that is unlikely but still possible”. [PDF p. 497]

- The 2024/25 results provided in response to MIPUG/MH I-15 do not appear to indicate that there was a greater opportunity for customers to manage their energy bills. There is also no striking evidence of any unintended consequences.

Responses to MIPUG/MH I-111a from the 2023/24 GRA indicate that Manitoba Hydro did not expect any adverse impacts to the GSL class RCCs or migration into the ZOR. [PDF p. 499]

- The results of PCOSS26 [Appendix 7.1] and findings of the Load Research Report [Appendix 4.2] appear to indicate that this expectation was met.

Manitoba Hydro testimony indicated a willingness to explore higher off-peak thresholds (or caps) for the definition of billing demand if ordered to do so.

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Part and Chapter:	MIPUG-09 (Friesen Report)	**Page #:**	31, 37 of 58
Topic:	Reliability		
Subtopic:	Reliability Metrics		

Preamble (if any):

On page 31, Mr. Friesen states:

> Current metrics used by Manitoba Hydro do not address the duration and frequency of momentary outages (i.e. less than one minute) that directly impact industrial operations.

On page 37, Mr. Friesen states:

> **Momentary Average Interruption Frequency Index (MAIFI):**
>
> A commonly used by metric by electric power utilities, MAFI is calculated as the “total number of customer interruptions less than a defined time” divided by the “total number of customers served.” This index is designed to track momentary power outages that can be hidden or misrepresented by an overall outage duration index such as SAIDI or SAIFI.

Question:

Please confirm whether other utilities or Electricity Canada publish reliability metrics for momentary outages. If confirmed, are there metrics specific to sub-transmission systems such that there would be comparators for Manitoba Hydro?

Rationale for Question:

To understand what metrics may be available with which to compare Manitoba Hydro.

Response:

a)

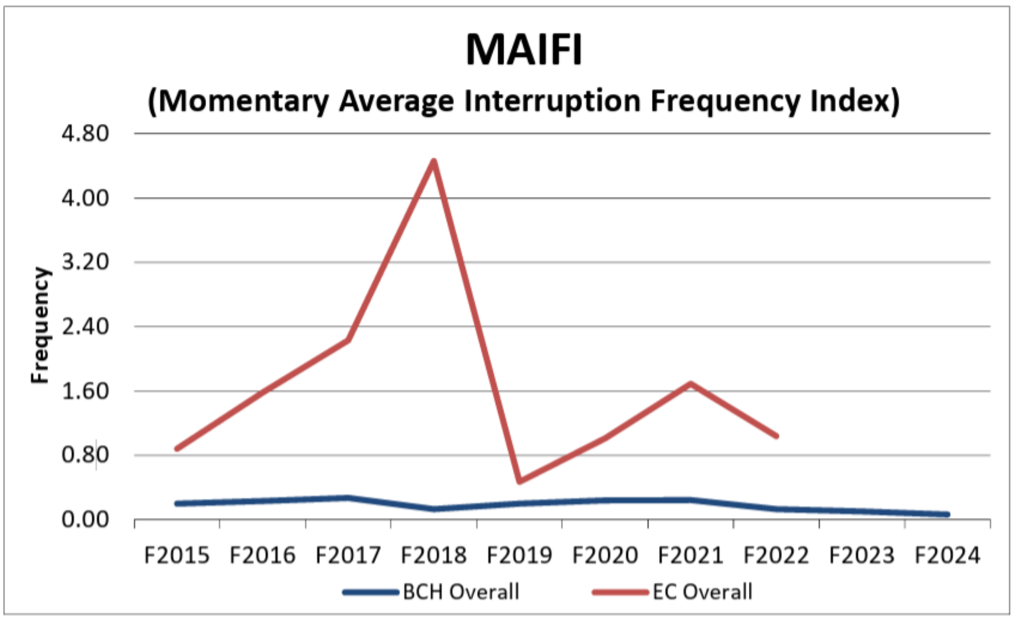
Directive 26 of the British Columbia Utilities Commission (“BCUC”) Order No. G-96-04 on BC Hydro’s F05/F06 RRA states that “BC Hydro is expected to present reliability indices (SAIF, SAIDI, CAIDI, ASAI, SARI, MAIFI, generation forces outages, availability, and generation outage rates), both combined and disaggregated (where applicable), on an annual basis with comparisons to the Canadian Electricity Association averages.”

Note: The Canadian Electricity Association became Electricity Canada on March 1, 2022.

The 2024 report, dated May 14, 2024, filed with the BCUC by BC Hydro includes references to the above noted reliability indices for distribution, transmission, and generation.11

PDF p. 5 includes a definition for MAIFI indicating "a measure of the frequency of momentary (less than one minute) interruptions per distribution customer served in a year"

PDF p. 11 includes a graph comparing customer momentary interruptions on the BC hydro distribution system and resulting MAIFI indices for any interruptions on feeders of less than one-minute duration, caused by disturbance on the distribution, substation, or transmission system.



Note: The customer momentary interruptions and the resulting MAIFI may not apply to the utility's total customer population in the Electricity Canada comparison. Momentary outages are any interruptions on the feeders of less than one-minute duration, caused by disturbance on the distribution, substation, or transmission system. Electricity Canada did not benchmark MAIFI in calendar 2022.

No MAIFI metrics specific to sub-transmission systems are provided in the BC report that could serve as comparators for Manitoba Hydro.

b)

Electricity Canada reports specific to distribution, transmission, and generation reliability are available, subject to payment. No specific references to MAIFI and/or sub-transmission reliability are made in the summaries, but references in the BC

[11] BC Hydro – 2024 Annual Reporting of Reliability Indices (https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-filings/rra/2024-05-14-bchydro-f05-f06-rra-directive-26-f2024.pdf)

Hydro report indicate that MAIFI indices may be available in Electricity Canada reports.[1,12]

c)

Section 4.2 (PDF p. 17) of a 2013 Canadian Electricity Report indicates that the Ontario Energy Board also requires reliability indices to be filed that include MAIFI, while indicating that distributors not having system capabilities enabling them to capture or measure MAIFI as being exempt from this reporting requirement.[13]

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[12] Electricity Canada – Reliability Intelligence Program (https://www.electricity.ca/programs/reliability-program/#:~:text=Benefit%20from%20one%20of%20the,for%20improvement%20and%20efficiency%20gains)

[13] Canadian Electricity Association, CAIFI and CEMI Reporting, 2013 CEA Analytics White Paper (https://www.electricity.ca/files/reports/english/SCC_2013_WhitePaper_CAIFI_CEMI_E.pdf)

PUB/MIPUG I-18

Part and Chapter:	MIPUG-09 (Friesen Report)	**Page #:**	38 of 58
Topic:	Reliability		
Subtopic:	Value of Unserved Energy		

Preamble (if any):

On page 38, Mr. Friesen states:

> MIPUG recommends that Manitoba Hydro improve its engagement and tools for assessing and recording the impact of reliability events on customer operations. This information should be used to establish a relevant metric for the cost of unserved energy as outlined in the Boston Report and supported by industry best practices. The cost of unserved energy can be an important consideration for assessing the economic benefits and prioritization of capital and operating investment in the Manitoba Hydro system.

Question:

Please provide more details on the Boston Report including where it may be found and the specific pages within that are relevant.

Rationale for Question:

To clarify the reference to the supporting document.

Response:

a)

The Boston Consulting Group report entitled "Project Heartbeat" dated July 6, 2016, was included as a redacted attachment to MFR 72 in the 2017/18 General Rate Application.

b)

The report included an appendix (PDF p. 317) with a "Heartbeat Workout Plan" dated August 22, 2016, identifying measures for "best-practice planning" that were expected to "maximize value" from capital spend. (PDF p. 344)

i) Prioritization criteria were noted as addressing the key question of "what metrics are used to prioritize across investments and how are those metrics evaluated?" with expected benefits for "flexibility to change criteria over time to reflect new priorities" and "removal of burden on planners to evaluate corporate risk values". (PDF p. 344)

ii) The report referenced change in "Expected Unserved Energy ("EUE") as a quantitative measure used by Manitoba Hydro to prioritize capital spend at the time the report was prepared, while also indicating planned changes, including the adoption of a Corporate Value Framework driving more quantification. (PDF p. 345)

c)

A subsection of the report (PDF p. 480) pertained to a Management Meeting for review of "Tie Line Economics" dated October 4, 2016, including a reference to:

i) "Estimated Loss of Load Expectation" and expected "unsupplied" energy in each scenario" as a factor considered in Manitoba Hydro's modeling of economic benefits to ratepayers based on the expected cost of outages.

ii) A tie line scenario considering an additional 698 MW import capacity of tie line access to outside generation in the event of an outage on the Manitoba Hydro system using a societal value of $10/kWh and redacted total NPV value was presented. (PDF p. 507)

iii) The societal value of $10/kWh referenced a "unserved energy study commissioned by Manitoba Hydro" (PDF p. 507), which was not included in MFR 72.

d)

The information noted in c) was repeated in a subsection of the report (PDF p.591) pertaining to a Capital Sub Committee review of Tie Line Economics. (PDF p. 536)

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Part and Chapter:	MIPUG-09 (Friesen Report)	**Page #:**	39, 48 of 58
Topic:	COSS		
Subtopic:	Further study of GSL 0-30kV cross-subsidization		

Preamble (if any):

On page 39, Mr. Friesen recommends:

- Manitoba Hydro analysis pertaining to “Potential for Reduction in Cross Subsidization” in the GSL 750 V – 30 kV subclass should be refined to consider differences in embedded unit costs for energy and demand that reflect the non-homogenous use and value of distribution assets used by larger customers connected to the distribution system via dedicated distribution substations/transformers and/or dedicated distribution feeders.

- Manitoba Hydro to develop a process by which larger GSL 750 V – 30 kV customers, better suited to sub-transmission level service, pay directly for dedicated Manitoba Hydro-owned distribution equipment used to connect their facility to the sub-transmission or transmission system and pay rates applicable to GSL30 – 100 kV customers that are more representative of the costs they impose on the system.

On page 48, Mr. Friesen states:

> The analysis does not address the core concern raised by MIPUG: that larger customers located near substations and served by dedicated assets may impose lower costs on the system than smaller customers relying on higher cost shared infrastructure. If proven to be the case, it can be assumed that these larger customers are paying rates for dedicated distribution equipment connecting them to the sub-transmission or transmissions systems that exceeds Manitoba Hydro’s cost-to-serve, conflicting with the principle of fair and reasonable rates based on costs.

Question:

a) With respect to the first recommendation for Manitoba Hydro to further analyze potential cross-subsidization, please explain how such an analysis would be used. Please identify the potential outcomes that such an analysis could lead to. Would the outcome potentially be a different customer class?

b) With respect to the second recommendation, please confirm whether any GSL 0-30kV customers have approached Manitoba Hydro with requests to connect to the higher voltage sub-transmission system. If confirmed, what have Manitoba Hydro's responses to these requests been?

Rationale for Question:

To understand how Manitoba Hydro could reduce cross-subsidization in the GSL 0-30 kV class.

Response:

a)

Manitoba Hydro's response to MIPUG/MH I-38 [PDF p. 123] indicates that four GSL 750 V – 30 kV customers are served via dedicated distribution facilities. The response to MIPUG/MH II-25 indicates that these dedicated substations and DSCs are supplied via 115 kV transmission lines or 66 kV sub-transmission lines and the customers are connected directly to the low voltage side of the substation and therefore require neither primary nor secondary distribution lines [PDF p.165].

The response also indicates that on strict basis of cost causation, it may be appropriate to entirely exclude these customers from the cost of distribution lines, in ta similar manner to how Centra Gas Manitoba treats the Mainline Firm class on the natural gas system. Manitoba Hydro notes that the adjustment could be similar to the existing 30% adjustment under Allocator D36 NCP Demand for secondary distribution [PDF p.165].

Based on the above information, Manitoba Hydro should be able to reconcile the costs for the low voltage portion of the dedicated distribution facilities and examine the opportunity for direct allocation of those costs to the applicable customers. Since the costs imposed on the distribution system by these customers are now recovered through direct allocation, it would appear reasonable that they become eligible for GSL demand and energy rates applicable to the GSL 30 – 100 kV or GSL >100 kV subclasses depending on the voltage level at which the high voltage side of their dedicated distribution facilities are connected.

Non-Dedicated Customers

Information related to the proportional share of consumption and demand that may classify a GSL customer as a principal customer served by non-dedicated distribution facilities was not available in this proceeding. It is anticipated that a greater, but still limited, number of additional large customers in this lower voltage GSL subclass are served as principal customers on a non-dedicated distribution substation or primary voltage distribution line, where they represent greater than 50 percent of the connected load. Segmentation on this basis could reflect on whether appropriate allocations of cost for non-dedicated distribution assets, particularly poles and wire, are being assigned to large GSL 750 V – 30 kV customers. An analysis on this basis would consider whether current allocations of poles and wire costs are fair and reasonable.

Existing allocators for non-dedicated station costs (D32) based on non-coincident demand appear reasonable for larger customers served by non-dedicated distribution stations. Allocators for Lines and Poles (D36) would appear to be more variable based on the anticipation that distribution stations may be in closer proximity to larger customers and therefore shorter in length.

Segmentation as outlined above, would provide a better understanding of the consumption, demand, and corresponding cost-to-serve imposed on the Manitoba Hydro distribution system by a small group of large customers within the GSL 750 V – 30 kV subclass.

Customer Class

The question about whether a different class could potential arise from this analysis is reasonable.

A detailed breakdown of consumption amongst the top 56 net-metered customers identified in Appendix 7.3 is not presently available. A simple comparison of the available information indicates that these customers are responsible for nearly 60% of total consumption within the GSL 750 V – 30 kV subclass. Average consumption comparisons illustrate that the highest grouping of interval-metered customers have average usage that is close to 4x greater than the subclass average, and between 9 and 34 times greater than the respective non-interval metered and lowest interval metered customer groupings. This comparison indicates that these customers are considerably larger than the average customer in this GSL class.

Customer Groups (interval metering)	Customers (qty)	Energy (GWh)	Energy Share		Avg Usage (GWh/cust)	Per Customer Ratios		
			(% interval)	(% total)		(total)	(non-interval)	(low interval)
Non-Interval Metered	147	299		17%	2.034	0.43	1.00	3.80
Lowest (interval metered)	56	30	2%	2%	0.536	0.11	0.26	1.00
Second (interval metered)	56	132	9%	7%	2.357	0.50	1.16	4.40
Third (interval metered)	56	283	19%	16%	5.054	1.06	2.48	9.43
Highest (interval metered)	56	1020	70%	58%	18.214	3.83	8.95	34.00
Total	**371**	**1764**			**4.755**			

Yellow	Appendix 7.3, Figure 2 (PDF p. 4)
Green	Appendix 4.2, Table 4.1 (PDF p. 26)
Pink	Calculated

A similar comparison of peak demand is limited by the available information provided in Appendix 7.3, Figure 3 and Appendix 4.2, Table 4.1. Appendix 7.3 used the sum of customer peak demands [PDF p. 4] while Appendix 4.2 used the class single highest peak demand during the 2022/23 study period [PDF p. 28]. Manitoba Hydro does however indicate that “the range in customer demands between the largest and smallest customers is similar to the range of energy usage” in Appendix 7.3 as illustrated by Figure 3 [PDF p. 4].

These comparisons clearly illustrate the non-homogeneous nature of the GSL 750 V – 30 kV subclass. An analysis of the costs imposed on the distribution system by this limited number of large GSL customers, accounting for a majority of consumption within the class, would be expected to provide a better understanding of where potential cross-subsidization exists between larger and smaller customers in this subclass. Is it anticipated that the grouping (or some portion of the group) will be sufficiently large to warrant consideration for whether they, as a sub-group of outliers, are subject to rates that are neither fair nor reasonable in proportion to the costs they impose on the distribution system. Is so, a new customer class may be warranted.

b)

Information pertaining to this question was not requested by MIPUG in IRs or provided by Manitoba Hydro in its filings.

Mr. Friesen is aware of GSL 750 V – 30 kV customers deliberating about whether to accept service at the sub-transmission level when submitting requests for service upgrades due to facility expansions. Manitoba Hydro service extension policies at that time, combined with the evolution of emerging distribution technologies (DSCs) that lowered costs for distribution substations, were significant factors for determining the outcomes of those discussions. Manitoba Hydro responses on those occasions may no longer align with current service extension policies, which are not available to customers in the public domain.

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Part and Chapter:	MIPUG-09 (Friesen Report)	**Page #:**	40 of 58
Topic:	Cost of Service Study		
Subtopic:	Proximity considerations in the COSS		

Preamble (if any):

On page 40, Mr. Friesen quotes from MIPUG's final arguments in the 2023/24 GRA:

> "Cost-of-service allocations should recognize that GSL 750 V – 30 kV customers with lesser capacity requirements have a greater need for distribution poles and wires than larger customers being supplied from dedicated utility assets located in closer proximity to their operations."

Question:

a) Please explain how cost of service allocations would recognize the differences between customers with differing capacity requirements or differing proximities to dedicated utility assets, either within the GSL 0-30 kV class or between GSL classes.

b) Please identify any jurisdictions that incorporate proximity or geographic location in their cost-of-service studies and provide a summary of how these allocations are made.

Rationale for Question:

To understand how the recommended allocations would practically be implemented.

Response:

a)

Given their limited number, information related to the costs for dedicated distribution facilities used to serve primary distribution customers should be available or easily identifiable within existing data sets maintained by Manitoba Hydro.

For customers served by non-dedicated distribution facilities, a minimum system study reflecting the quantity, size, and length of distribution lines suitable for serving larger customers with higher demands may be useful for determining the portion of total distribution line costs that are applicable to larger primary service GSL customers. Performing such a study may require additional information pertaining to the customer class breakdown for individual distribution feeders to establish a stronger context for costs related to serving larger GSL customers versus higher density residential and/or commercial developments.

Manitoba Hydro did not provide aggregated information for distribution customers served via the 30 – 100 kV sub-transmission system in response to MIPUG/MH II-11d, so it is unclear about the level of detail information that Manitoba Hydro maintains regarding the number and type of customers that are served by each distribution feeder [PDF p. 66].

Given that the distribution system serves a variety of customers beyond the GSL 750 V – 30 kV subclass, including the Residential, GSS, GSM, and ARL rate classes, the above noted minimum system study should be accompanied by an updated study reviewing the current 70:30 split of primary and secondary distribution costs that are based on an analysis from 1991. The absence of a current study has influenced subsequent decisions about the classification split between customer and demand costs in 2016.

b)

The evidence of Ms. Davies points to the use of minimum system studies by Nova Scotia Power (in-progress), Ontario Distribution Utilities (which appear to reference customer density), Newfoundland Power, FortisBC (inclusive of peak load carrying capacity adjustments), and SaskPower (inclusive of peak load carrying capacity adjustments).

While several jurisdictions reference customer density as a factor for classification of demand and customer costs, no other evidence has been found indicating consideration for proximity and/or location. Lower customer densities referenced in these studies are generally indicative of rural locations where per customer lengths of distribution line are greater than higher density urban locations.