GSS-GSM/MIPUG-1

Part and Chapter:	Bowman evidence	**Page #:**	59
Topic:	Rate Design		
Subtopic:	AMI		

Preamble (if any):

On page 59, Mr Bowman states that:

> However, price signals related to peak consumption are not felt whatsoever by residential customers. The signals are felt in relation to use of power at all times throughout the year, equally. Hydro notes that there are ways to address this issue based on the experience of peers, but suggests such options are not available without AMI. This is not correct. There are rate design options which improve price signals and intraclass fairness, which can be implemented without AMI, including blocked rates (e.g., a price per kW.h for basic usage each month, with a higher price above that usage) and seasonal rates (e.g., apply a higher per kW.h charge in the months of December, January and February than in the rest of the year). It is not apparent that Hydro has fully explored these options, to the detriment primarily of residential class intraclass fairness, but also to conservation price signals at peak times.

Manitoba Hydro describes its approach to designing the GSS and GSM rate structures in response to GSS-GSM/MH II-14a-e Attachment 1 pages 3 of 12. The GSM rate structure has since had its block structure collapsed from three blocks to two as proposed in the last GRA. Page 24 of Ms. Davies evidence on behalf of GSS-GSM compares the F2026 proposed GSS and GSM rates with PCOSS26 unit costs.

Question:

a) Does Mr. Bowman draw the same conclusions for the GSS and GSM rate classes as referenced above regarding the residential class. Please explain.

b) Please provide a comparison of other electric utilities in Canada that employ differing energy prices for broad periods such as months, seasons, etc. and explain the basis employed to set the differing energy charges.

c) If energy rates are increased for periods as long as multiple months at a time, without respite - such as overnight, etc.), would it be possible for customers such as residential, GSS and GSM to shift usage to avoid increased costs? Please explain.

d) Please provide examples of any other rate design/structure options that could be implemented without AMI that provide smaller users, such as residential and commercial, the opportunity to shift usage periods in an effort to peak shed. Provide reference to other jurisdictions where these rates are employed if possible.

Rationale for Question:

Response:

a)

For General Service Small Non Demand, this relationship likely holds.

For GSS Demand and GS Medium, the price signal issues do not arise in the same way due to demand charges, as well as modest demand ratchets.

b)

Mr. Bowman has not conducted a survey of Canadian utilities for winter versus summer price adjustments. However, it is noted that there are multiple utilities with some degree of different seasonal cost profiles for customers, such as the changing Time of Use blocks in Ontario for Residential customers, and the relatively new Rate Flex D in Quebec. New Brunswick Power has also been directed to investigate increasing seasonal cost signals (Proceeding 554). Newfoundland Hydro and Newfoundland Power maintain an option Rate 1.1S which has winter premium energy charges, with reduced non-winter energy charges.

It is expected that in each case, the relevant facts from the jurisdictions would guide the development, so it is not immediately apparent how these facts may translate to Manitoba Hydro’s cost structure.

c)

No, not likely. The purpose of improved cost tracking is not necessarily to drive changes in behavior, it is to better align rates with costs.

However, with respect to such factors as solar development, the economics of solar may be inappropriately skewed at the present time, if the solar installations primarily contribute power at lower value times, but are offsetting higher priced energy unit purchases, where this higher price derives not from daytime summer hours but from dark winter hours. Improving cost signals would help ensure this solar resource is appropriately developed.

d)

Typically load shifting is a short-term variation, so cost variations would need to happen over a fairly short period (e.g., over the course of a day, up to a week). This is difficult to enable without AMI.

The only example of which Mr. Bowman is aware of where pricing and availability could be implemented without AMI was interruptible heating that may have previously been used in Quebec (Rate DT), where a second meter was required that was only operable when the temperature was in a target range (i.e., not too cold). This type of delivery system has not otherwise been common in Canada.

GSS-GSM/MIPUG-2

Part and Chapter:	Bowman evidence	**Page #:**	41 – 42, 57
Topic:	Cost of Service		
Subtopic:	Generation Classification		

Preamble (if any):

In this section Mr. Bowman recommends that:

> 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.

On page 57, Mr. Bowman notes that:

> As the importance of peak demand increases, it is advisable to develop rate mechanisms which improve the signals and economic incentives for customers to avoid high load levels at system peak times. A longstanding example is the curtailable option available to customers who opt in (when the program is open to new entrants). This type of offering should be of increasing value to the system, and compensation for customers should reflect this increased value.

Question:

a) Does Mr. Bowman conclude similarly that water rentals and/or variable hydraulic operating and maintenance expense should be classified using the SLF, similar to all other generation? Please explain.

b) For future planned ‘dispatchable capacity’ generation resources, if built, does Mr. Bowman similarly believe these assets should be classified on the basis of the SLF? Please explain.

c) Is it Mr. Bowman’s understanding that in the COSS, the costs of industrial load curtailment are functionalized as generation and classified on a similar basis as other peaking assets? Please explain.

Rationale for Question:

Response:

a)

The focus of the evidence is on classification and allocation of fixed costs (either capital assets or committed contracts) for power supply, not on Operating and Maintenance costs, or water rentals.

It is a reasonable extension that variable generation operating and maintenance costs, and water rentals, should also be part of the complement of costs that are not disentangled for the purposes of applying a coherent SLF classification. However, this was not the focus of the evidence in this proceeding as (unlike wind) there is no material revision to the incurrence of water rentals or variable operating and maintenance costs since Order 164/16.

b)

If the SLF continues to be used on the basis of a focus on the loads to be met by the generation, rather than a granular analysis of each generator cost, then yes, the SLF should also apply to dispatchable capacity resources.

If this is not the case (e.g., if wind is 100% energy) then new capacity resources such as CTs should be classified to 100% capacity.

c)

The typical practice of demand cost allocation would approach industrial customer curtailment in one of two ways. Either the industrial customer loads be adjusted downwards to reflect the assumption that the loads are interrupted (e.g., the approach used in Nova Scotia), or the costs of credit paid to the customers be recovered from all customers via a capacity classified cost (e.g., the approach used in Newfoundland and Labrador).

Manitoba is unique in considering the CRP costs as a component of DSM costs, and recovering these costs from customers through a SLF classification of DSM costs (as such, large parts of the CRP costs as classified as energy). This is further support for not granularly analyzing the individual cost components of generation, and applying a SLF classification to all generation costs, including wind (and by extension water rentals, etc.).

GSS-GSM/MIPUG-3

Part and Chapter:	Bowman evidence	**Page #:**	13
Topic:	Figure 2 – Annual Cost of Capital & Production		
Subtopic:			

Preamble (if any):

Question:

a) Please provide underlying values, references and supporting calculations for Figure 2.

b) Please explain the driver of the stepped increase for 2026-28 GRA (green line) around year 2037 in Figure 2.

   a. Was this cost driver present in the 2023-25 GRA amounts (orange line)?

Rationale for Question:

Response:

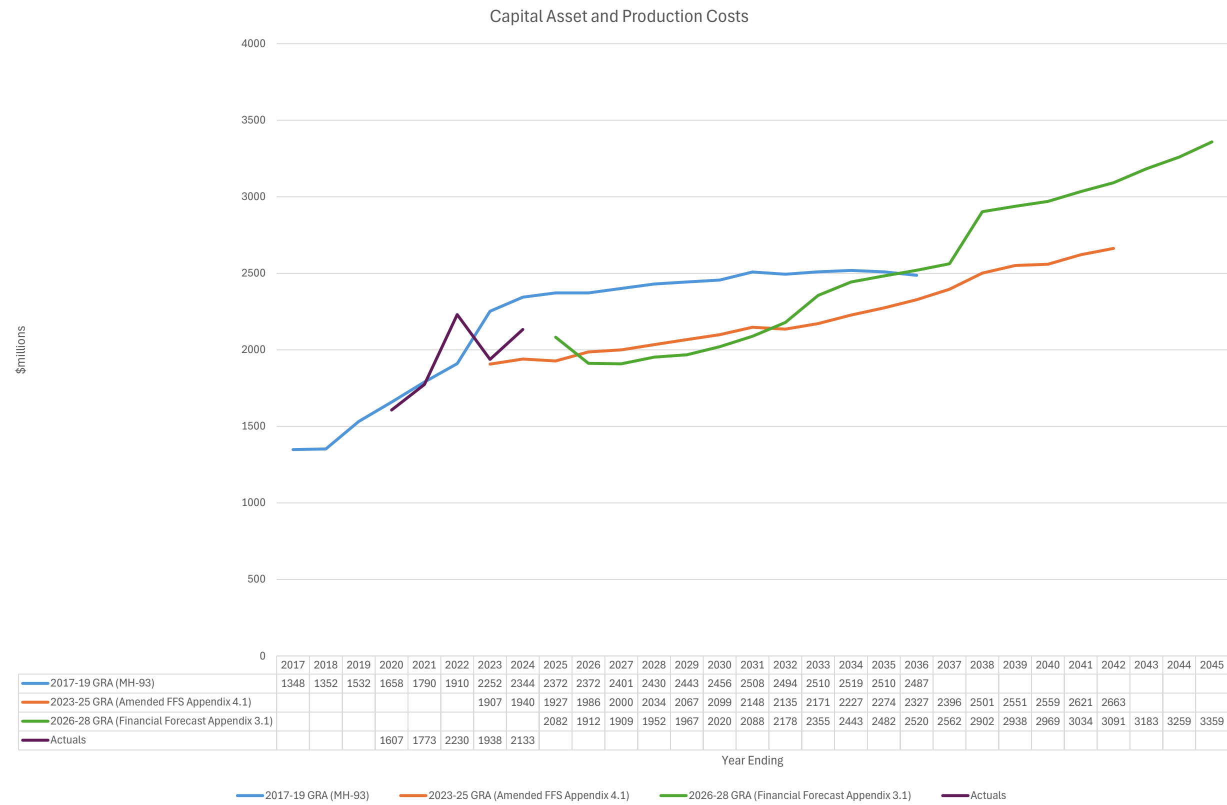
a)

The input data for Figure 2 is provided below. The values in each year are the sum of finance expense, less finance income, plus depreciation plus water rentals, plus fuel and purchased power, plus capital and other taxes.

It does not include operating and maintenance costs, nor other expenses, nor corporate allocation, nor any effects of net movement.

b)

The stepped increase reflects new assets coming into service. This cost driver was not present in the 2023-25 GRA amounts.



	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
2017-19 GRA (MH-93)	1348	1352	1532	1658	1790	1910	2252	2344	2372	2372	2401	2430	2443	2456	2508
2023-25 GRA (Amended FFS Appendix 4.1)							1907	1940	1927	1986	2000	2034	2067	2099	2148
2026-28 GRA (Financial Forecast Appendix 3.1)									2082	1912	1909	1952	1967	2020	2088
Actuals				1607	1773	2230	1938	2133							

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045
2017-19 GRA (MH-93)	2494	2510	2519	2510	2487									
2023-25 GRA (Amended FFS Appendix 4.1)	2135	2171	2227	2274	2327	2396	2501	2551	2559	2621	2663			
2026-28 GRA (Financial Forecast Appendix 3.1)	2178	2355	2443	2482	2520	2562	2902	2938	2969	3034	3091	3183	3259	3359
Actuals														

GSS-GSM/MIPUG-4

Part and Chapter:	Bowman Evidence	**Page #:**	
Topic:	COSS Distribution Classification		
Subtopic:	Distribution Plant Assets		

Preamble (if any):

Evidence filed on behalf of the GSS-GSM, by Ms. Davies, in Section 6 recommends that distribution plant asset costs, especially Wires & Poles and potentially Transformer costs, should be changed in this proceeding and classified on the basis of both energy and demand. This is based on a Canadian jurisdictional comparison, past precedent of Manitoba Hydro, current experience in Manitoba with Centra Gas, and cost causation.

Currently, Manitoba Hydro classifies Poles & Wires and Transformer costs 100% to demand (allocated using class Non-Coincident Peak demand).

Question:

a) Please provide Mr. Bowman's perspective on Manitoba Hydro's current approach to classifying distribution plant assets and whether or not he supports a change to the current methodology.

Rationale for Question:

GSS-GSM would like to understand the perspectives of the other Cost of Service experts in this proceeding on this matter.

Response:

There is no reasonable basis to consider distribution wires and poles to be a 100% demand related cost. Manitoba Hydro is an outlier among Canadia peers in adopting this approach.

The vast majority of distribution costs are installed to provide a basic system that connects and integrates the large expanse of customers throughout Manitoba. This system is required regardless as to the particular peak demands of any individual customer, or the combination of customers. A more limited complement of the costs of the distribution system are demand-related and are driven by the need for investment at a size above the minimum system size.

GSS-GSM/MIPUG-5

Part and Chapter:	Evidence of Mr. Bowman,	**Page #:**	31
Topic:	Future DSM Contribution to Domestic Loads		
Subtopic:			

Preamble (if any):

In Table 3, Mr Bowman provides the following comparison of DSM contribution and concludes it will provide less and less peak demand resource in related to the energy savings targets.

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 also notes that:

> Table 3 above provides the future DSM resource that is projected as of the forecasts from the three most recent GRAs. The values naturally decline in each subsequent GRA, as the DSM values in any given GRA only include future DSM – past DSM is included in the base domestic load forecast. This means that DSM undertaken in 2020 is included in the DSM projected in the 2017-19 GRA, but is not included in the DSM projection for the 2026-2028 GRA because it is in the customer load forecast.
>
> Table 3 indicates that in past GRAs, the projected DSM yielded material energy savings, but in each previous GRA, the system percentage savings in capacity exceeded the savings in energy (as a percentage of system load). This is no longer the case in the latest GRA. At this time, the DSM activities are expected to save more energy in relation to capacity (6.05% versus 5.58%). If the DSM energy: capacity ratios had remained as projected in the previous GRA, the capacity savings would be 141% of the relative energy savings (11.51%/8.18%) which would yield a 2033/34 projected capacity

savings in the current GRA forecast of 8.51% rather than the 5.58% now projected. In MW terms, this would yield 491 MW of DSM capacity savings, or 169 MW added savings compared to the GRA forecast (which is material).

Question:

a) Please provide an updated comparison table that includes GWh and MW savings from demand response.

   a. Please explain whether the addition of demand response savings change the conclusions made with regard to demand side energy and capacity ratios,

b) Given the above explanation and that the above comparison is not an 'apples to apples' comparison of future cumulative savings since the older studies will include more years of actuals (and therefore the savings will be included in load forecast, not in DSM savings), would a rolling year comparison (e.g. comparing the 8^{h} forecast year for each study) have been a more appropriate benchmark comparison to control for realized savings?

   a. If so please provide and comment on whether this changes the conclusions drawn in relation to capacity and energy savings from DSM.

   b. If not, please explain the significance of the 2033/34 year utilized and provide an explanation on why it is appropriate to compare in this manner.

c) At the time of each study, what was then the anticipated 'need' date for future energy and capacity resources?

Rationale for Question:

Response:

a)

Demand response is a different resource than energy efficiency-oriented DSM. The purpose of the comparison is to show that in relative terms, Efficiency Manitoba's energy efficiency savings are now capturing more energy savings in relation to capacity savings than was the case in earlier forecasts.

Hydro is also now proposing to pursue demand response (in both the 2023-2025 and 2026-2028 GRAs) but this is a supplemental capacity resource (that comes with its own costs and investment) separate from energy efficiency and is not appropriately combined for the purposes of the above table. Further, the above tables are based consistently on the "no new resources" tables, and Demand Response is a new resource so is not included.

b)

The analysis uses 2033/34 as it is reasonably within the horizon at which new investments of commitments to resources being to play a material role in Hydro's financial forecast (whether wind or capacity-driven investment, or demand response, etc.). However, in order to address the concerns over consistent assumptions, the table below produces the values for the 8th year of each respective forecast:

Comparing DSM in Year 8 of the Respective Forecasts

	2017-19 GRA App 7.3	2023-2025 GRA App 5.6 and MFR 43 (Tab 10)	2026-2028 GRA App 4.3 and MFR 39 (Tab 9)
Domestic Load Forecast Before DSM (GW.h)	29,110	25,685	27,416
DSM	2,688	1,678	1,413
as a percentage of domestic load	9.2%	6.5%	5.2%
Domestic Demand Before DSM (MW)	5,318	5,023	5,253
DSM	638	431	249
as a percentage of domestic load	12.0%	8.6%	4.7%

As shown in the table above, the relative contribution of DSM to energy versus demand has been decreasing. In each case these values are derived from the "no new resources" version of the tables, so are consistent with respect to the assumptions about curtailable rates (none include curtailable rates program capacity). The same conclusions hold as in the original analysis.

c)

Please see Table 6 of Exhibit MIPUG-8.

GSS-GSM/MIPUG-6

Part and Chapter:	Evidence of Mr. Bowman, Section 4.4	**Page #:**	31
Topic:	Class Peak Demand Contribution		
Subtopic:			

Preamble (if any):

Mr. Bowman's recommendations with regard to Manitoba Hydro's Load Research Report includes:

RECOMMENDATION 4: The new Load Research Report is not suitable for use in preparing PCOSS allocations, as it mutes coincident peak estimates as compared to the past methodology, and the synthetic load output does not exhibit load estimates (such as System Load Factors) that accord with known system characteristics.

RECOMMENDATION 5: The PCOSS methodology should focus on a more refined method of estimating each class's share of peak load, incorporating fewer peak hours. The methodology should also include an adjustment to align forecast peak loads to the planning conditions for which investment was made on the system (i.e., very cold weather conditions, not average winters).

Question:

a) Does Mr. Bowman draw the same conclusions regarding use of the Load Research Report for preparing PCOSS allocations for the non-coincident peak (NCP) demand? Please explain.

b) What does Mr. Bowman propose PCOSS26 and potential rate rebalancing should be based off of for rates from F2026 – F2028 in the meantime if not the new Load Research Report, while Manitoba Hydro develops a more refined method?

c) Does eventual implementation of AMI for customers render Mr. Bowman's second recommendation temporary - i.e. is this a short-term issue that will be resolved when customer class peak and non-coincident peak can be more accurately measured (similar to GSL >30kV rate classes currently)? Please explain.

Rationale for Question:

Response:

a)

Mr. Bowman has not analyzed the new load research approach for NCP and cannot comment on the methodology use for this purpose.

b)

In the absence of better data, the Board should determine that no increases are appropriate for the GSL 30-100 kV class, the GSL >100 kV class and the GSS-ND class. The PCOSS conclusions in this regard already support this rate rebalancing, so further PCOSS refinements that further increase residential hearing peak responsibility would, if anything, strengthen this conclusion.

c)

Not necessarily. First, AMI data collection can take a considerable period before reliable multi-year datasets will be available. Second, the availability of AMI data would only address Recommendation 4 in Mr. Bowman’s submission, not Recommendation 5, which still required implementation.

GSS-GSM/MIPUG-7

Part and Chapter:	Evidence of Dale Friesen	**Page #:**	2-2 – 2-6 & 2-12
Topic:	GSL Rate rebalancing		
Subtopic:	Cost based rates		

Preamble (if any):

With regard to GSL class rate rebalancing progress between energy and demand, Mr. Friesen states the following:

> The 2026 GRA indicates that the "results of PCOSS26 show energy and demand unit costs that are more closely aligned with approved rates than was the case at the 2023/24 & 2024/25 GRA". A modest rebalancing outcome, following two years of demand-only increases that ranged from 1.7% to 3.0%, was confirmed in Manitoba Hydro's response to Coalition/MH I-157c. A comparison of Figures 2.1 and 2.2 indicate that the two higher voltage subclass experienced movement of two percentage points in the net balance between demand and energy costs and revenues. The lower voltage subclass experienced movement of three percentage points in the net balance between demand and energy costs and revenues. A closer examination of the PCOSS results show that the movement in demand and energy costs was an equal or greater contributing factor for reductions in the imbalance when compared to the demand-only rate increase.

Table 2.1 of Mr. Friesen's evidence compares PCOSS26 unit costs to proposed rates for each GSL rate class.

Question:

a) Is Mr. Friesen recommending each GSL rate class should be moving towards perfectly cost based rates (i.e. energy rates exactly equal to energy unit costs, demand rates exactly equal to demand unit costs)? If not, please explain if additional objectives (outside of cost-based, efficiency, affordability) should be considered for continued rebalancing between demand and energy rates (such as consideration for individual customer impacts as discussed in Section 2.6.4, etc.).

   a. Please specify if different objectives are appropriate for each GSL rate class with respect to continued rebalancing.

b) Is Mr. Friesen aware of other jurisdictions undertaking similar interclass rebalancing? If so, please provide examples including rationale and methodology for approach to interclass rate rebalancing, including whether perfectly cost based rates are the goal.

Rationale for Question:

Response:

a)

Mr. Friesen is recommending that each GSL rate class move towards a more representative balance between demand and energy unit costs and revenues. The pace with which this is achieved should be tempered and adjusted to preserve the principles of gradualism and predictability.

As an example, rate impacts for the most heavily impacted lower load factor customers in each GSL subclass should be a consideration when establishing the pace of rebalancing efforts that increase the weighting of demand component rates. Additionally, consideration should be provided for long-delayed corrections to high RCC ratios, measured and anticipated changes in consumption behavior and COSS methodologies impacting demand and energy cost allocations, anticipated costs and related price signals associated with mitigation of capacity and supply constraints, etc. The impacts of these factors may impact the relative magnitude and pace of demand rate increases and energy rate decreases. The emergence of alternative rate options, including demand response programming, may assist lower load factor customers in mitigating higher than average rate impacts associated with increasing demand rates, and improve their risk tolerance for rebalancing efforts.

Each GSL rate class has a different balance between demand and energy component costs and revenues, indicating different degrees of rebalancing and pace for rebalancing efforts. The two higher voltage GSL subclasses have significantly higher RCC ratios than the lower voltage GSL subclass, while the lower voltage subclass has a greater spread between embedded unit costs and rates than the higher two voltage subclasses, indicating a potential need for different approaches. There are also differences in the class average load factors that must be taken into consideration as they impact the ratio of demand to energy costs within energy bills, and resulting sensitivity to increases in demand rates.

While the objectives are similar between GSL subclasses, the pathway may vary in its pace and relative adjustments to demand and energy component rates.

b)

At this point, Mr. Friesen has not actively researched similar efforts in other jurisdictions. It would not be unexpected for other jurisdictions to be pursuing similar efforts to improve alignment between component rate price signals and key cost drivers.

A quick scan identified a SaskPower 2022-23 General Rate Application proposing a decrease in energy rates and increase in demand rate citing a desire to slowly phase back on recovery a demand-related costs through energy charges. There was insufficient time to undertake a detailed review of the Application and resulting outcomes.

GSS-GSM/MIPUG-8

Part and Chapter:	Evidence of Dale Friesen	Page #:	Section 2.6
Topic:	Rate Rebalancing		
Subtopic:	Cost Based Rates		

Preamble (if any):

Mr. Friesen provides the following table:

Table 2.6 – Overall Rate Change Under Illustrative Opposing 3.5% Scenario

Demand Rate	Annual Average Rate Impact (%)					
	Load Factor			Variance		
	0.40	Avg	0.90	Below	Above	Range
GSL <30 kV	-0.18%	-0.73%	-1.50%	0.55%	-0.77%	1.32%
GSL 30 - 100 kV	-0.35%	-1.27%	-1.64%	0.92%	-0.36%	1.28%
GSL >100 kV	-0.49%	-1.49%	-1.74%	1.00%	-0.25%	1.25%

Demand Rate	3.50%	Avg Increase
Energy Rate	-3.50%	Avg Increase

Question:

a) Please provide references and/or supporting calculations for Table 2.6

b) Please provide the resulting revenue impact of the 'illustrative opposing 3.5% scenario' for F2026 rates. Does this scenario result in the revenue increase being requested by Manitoba Hydro for each class in F2026?

c) Is it correct to conclude from the above table, that in the illustrative opposing scenario above, the average rate increase for GSL >100kV customers with below average load factors will be 1.0%, where as the average rate decrease for GSL >100kV rate customers will be 0.25?

d) What is the 'average' load factor for each rate class in used in Table 2.6. How is this calculated?

e) Has Mr. Friesen analyzed the full range of rate impacts in the above scenario for each GSL rate class? If so, please provide.

f) If implemented, does this scenario result in more opportunity to achieve savings as a result of billing demand definition changes (through higher demand charges compared to energy)? Please explain.

Rationale for Question:

Response:

a)

Rate impacts are determined using comparisons of total unit costs for demand and energy ($/kWh) as a function of load factor. Producing average unit cost curves for a two-part rate structure is simplified by the absence of fixed charges within the GSL rate structure. The unit costs are relevant and scalable to any combination of energy consumption and demand for a defined billing period.

The following calculations are used to produce a unit cost curve:

i. Demand rate costs are determined by multiplying the demand charge by a base unit(s) of demand.

ii. Energy rate costs are determined by multiplying the energy charge by the base unit(s) of demand, billing period hours, and load factor.

iii. Sum of Demand and Energy rate costs are then divided by the multiplication of base unit(s) of demand, billing period hours and load factor, providing an average unit cost for energy ($/kWh)

iv. The above calculations are repeated for the desired range of load factors, creating a unit cost curve as a function of load factor. Unit cost curves are prepared for each rate scenario, with differences between the unit costs at a common load factor representing a rate impact that can be compared across a range of load factors.

Table 2.6 provides the three-year average annual rate impact using unit cost curves for approved rates in effect on April 1, 2024, as compared to unit cost curves for rates scenarios using the noted annual 3.5% increase to demand charges and 3.5% decrease to energy charges for January 1, 2026, 2027, and 2028.

b)

As noted in evidence, the illustrative scenario is intended to highlight an approach for achieving the identified rate objectives established by Manitoba Hydro during the 2023/24 GRA, which included:

i. **Objective 1 (cost-based rates)** - Recovery of revenue requirements and targeted class revenue cost coverage ratios in the range of 95% - 105%.

ii. **Objective 2 (efficiency)** - Price signals that correspond with underlying embedded and marginal costs, improving alignment with embedded costs of service, and

iii. **Objective 3 (affordability)** - Magnitude of bill impacts created by rate design changes, including a phased approach to rate rebalancing with moderate bill impacts.

Achieving those objectives within the rate framework presented by Manitoba Hydro in this GRA proceeding is not possible, given the:

- Starting level of unbalance between embedded component costs and component rate revenues,
- RCC coverage ratios for two higher voltage GSL subclasses that have remained above the 95% - 105% ZOR for about three decades, and
- Necessity for upwards adjustments to demand component rates and corresponding downward adjustments to energy component rates.

c)

The conclusion drawn in request c) is incorrect.

The average annual rate impact for a GSL >100 kV customer with a load factor of 0.40 would be -0.49%, while the corresponding impact for a customer with a load factor of 0.90 would be -1.74%.

The below and above values referenced in request c) are the respective variances from the class average annual rate impact of -1.49%. The range value represents the difference in average annual rate impacts between the customers with a load factor of 0.40 and 0.90.

d)

The class average load factors for the three(3) GSL rate classes were calculated from the Billable Demand and Metered Energy provided in Table A2 [Appendix 7.1, PDF p.15].

e)

The range of three-year average annual rate impacts for 3.5% opposing rate scenario used in the illustrative example from evidence are provided below.

Three-Year Average Annual Rate Impact (3.5% Opposing Rate Scenario)			
Load Factor	**GSL >100 kV**	**GSL 30 - 100 kV**	**GSL <30 kV**
0.05	2.50%	2.57%	2.65%
0.10	1.75%	1.86%	1.98%
0.15	1.17%	1.30%	1.44%
0.20	0.71%	0.84%	1.00%
0.25	0.32%	0.46%	0.63%
0.30	0.01%	0.15%	0.32%
0.35	-0.26%	-0.12%	0.05%
0.40	-0.49%	-0.35%	-0.18%
0.45	-0.69%	-0.56%	-0.39%
0.50	-0.87%	-0.73%	-0.57%
0.55	-1.02%	-0.89%	-0.73%
0.60	-1.16%	-1.03%	-0.87%
0.65	-1.28%	-1.16%	-1.00%
0.70	-1.39%	-1.27%	-1.12%
0.75	-1.49%	-1.38%	-1.23%
0.80	-1.58%	-1.47%	-1.32%
0.85	-1.67%	-1.56%	-1.41%
0.90	-1.74%	-1.64%	-1.50%
0.95	-1.81%	-1.71%	-1.57%
1.00	-1.88%	-1.78%	-1.64%

f)

Rebalancing to current embedded unit demand costs would provide a stronger price signal for capacity, supporting an opportunity for greater demand savings under the change in the definition for billing demand implemented by Manitoba Hydro effective April 1, 2024.

Higher demand rates would not however mitigate the constraints outlined in Sections 3.4.2 and 3.5 of Mr. Friesen's evidence. Constraints related to the structure of the billing demand definition, revenue neutral adjustments, and cap imposed on off-peak demand remain despite changes in demand rates. Addressing these constraints will require a revision to the revenue neutral methodology and cap on off-peak demand.

GSS-GSM/MIPUG-9

Part and Chapter:	Evidence of Dale Friesen	**Page #:**	
Topic:	Rate Rebalancing		
Subtopic:	Cost Based Rates		

Preamble (if any):

Mr. Friesen provides a comparison of PCOSS unit costs to GSL 0-30kV rates in Table 2.1 of his evidence. Ms. Davies provides a similar comparison (for F2026) on page 24 of her evidence for the GSS and GSM rate classes.

In response to GSS-GSM/MH I-11a & GSS-GSM/MH II-9c&d, Manitoba Hydro provides information on the GSM rate class and briefly in comparison to the GSL 0-30kV rate class. The response to MIPUG/MH I-34 provides class consumption breakdown by sector for both the GSM and GSL 0-30kV classes.

Question:

a) Based on Mr. Friesen's understanding of the GSL 0-30kV and GSM rate classes, what are the main differences between customer type, electricity and system usage? Are there any similarities between the two classes on the basis of customer type, electricity usage, and/or system usage? Please explain.

b) From review of GSM rate structure compared to PCOSS unit costs, would Mr. Friesen recommend any adjustments to the current Manitoba Hydro proposed rate increase for the GSM rate structure on the basis of a cost based rates? Please explain.

c) Does Mr. Friesen believe similar billing demand definitional changes could be implemented for the GSM rate class as he is proposing in Section 3.0 of his evidence? Please explain why or why not.

Rationale for Question:

Response:

a)

Mr. Friesen did not have sufficient time to complete a thorough comparison of the GSM and GSL 750 V – 30 kV classes.

An initial examination shows that the GSM class has a larger number of customers than GSL 750 V – 30 kV (2,193 vs 347) with a significantly lower average energy consumption (1,403 MWh vs 5,209 MWh) and lower per customer coincident peak demand (225 kW vs 720 kW) and non-coincident peak demand (250 kW vs 819 kW). These findings are based on Table 4.1 [PDF p. 83] of the 2022/23 Load Research Report [Coalition/MH I-143, Attachment 2],

Similar information to that provided in the Excel attachments to GSS-GSM/MH 1-9 and GSS-GSM/MH II-11 was not available for the GSL 750 – 30 kV subclass.

Table 1 from the response to GSS-GSM/MH I-11 appears to indicate that the GSM class has a much higher concentration of commercial customers (74% vs 41%) and lower concentration of industrial customers (16% vs 49%), with a similar share of agricultural customers (10%). Average customer usage in all segments also appears to be significantly lower for the GSM class. This outcome may be influenced in part by Manitoba Hydro policy that does not provide secondary transformation exceeding 2.5 MVA requiring larger customers to become GSL 750 V – 30 kV customers.

b)

Mr. Friesen's evidence advocates for cost-based rates, through rebalancing of demand and energy component rates and embedded unit costs for capacity and energy. His evidence recognizes the large degree of imbalance in the GSL rate structures, where demand rates are lower than embedded costs (70% – 85%) and energy rates are higher than embedded costs (120% - 130%).

Supporting the principles of gradualism and predictability, Mr. Friesen recommends a multi-year approach that achieves a reasonable degree of balance within 3 – 5 years. Doing so minimizes the negative rate impacts of rebalancing for lower load factor customers that will see an increase in their average cost of power ($/kWh) due to a greater emphasis on demand costs.

Unlike the approach taken by Manitoba Hydro in the prior 2023/24 GRA, Mr. Friesen does not recommend demand-only rate increases to achieve rebalancing objectives. Doing so, creates additional hardship on lower load factor customers, reducing the pace at which rebalancing can be achieved without unsustainable rate impacts. The demand-only approach also does not address concerns about high RCC ratios for the two higher voltage GSL subclasses.

Mr. Friesen's evidence suggests an approach where demand rates are raised in parallel with reductions in energy rates. The combination of these two changes, minimize rate impacts for lower load factor customers, who maintain a significant share of energy only costs despite their lower load factor consumption.

Application to GSM Rate Class

The approach recommended by Mr. Friesen could be applied to the GSM rate class, with recognition for the added complication related to fix monthly charges that are currently set at about 7% of embedded customer unit cost allocations. The shortfall in fixed monthly charges represents about $12.6 M in customer costs that are currently recovered through energy rates, amounting to approximately 2.3 cents per kWh, or about 24% of the first-tier energy rate (first 19,500 kWh). In theory, increasing the fixed monthly charge with a corresponding reduction in the first-tier energy rate would reduce rate impacts to smaller GSM customers with lower levels of consumption.

Increasing demand charges also carries an added complication due to the current waiver on capacity charges for the first 50 kVA of monthly demand. It is estimated that this waiver accounts for approximately 1,281,2000 kVA of billable demand annually or about $17 M in unbilled demand charges, that are currently recovered through energy charges. $17 M represents about 11% of allocated demand costs, and amounts to approximately 3.2 cents per kWh, or about 32% of the first-tier energy rate. Increasing the fixed monthly charge and eliminating the first 50 kVA waiver would allow for an approximate 5.5 cent per kWh reduction in the first-tier energy rate, bringing the energy rate down to 3.6 cents per kWh, below the second-tier energy rate of 4.7 cents per kWh and closer to the 3.96 cents per kWh embedded cost of energy. This GSM analysis represents a perfect alignment between unit rates and unit embedded costs, which may not be a desired outcome. Variations on this approach may however be used to achieve desired objectives.

c)

In principle, a similar definitional change could be implemented for the GSM rate class. A key impediment for such a change is the lack of interval metering for most GSM customers. It is anticipated that larger GSM customers may in some instances have interval metering.

While a stronger on-peak capacity price signal should raise awareness among customers in this class about the importance of capacity in the system, it may also increase frustration and irritation among the many agricultural, commercial, and light industrial customers in this rate class that may not have substantive loads or opportunity to shift load into the off-peak period hours due to the nature of their business hours and single-shift operations.

GSS-GSM/MIPUG-10

Part and Chapter:	Evidence of Dale Friesen	**Page #:**	Section 3.6
Topic:	Billing Demand		
Subtopic:	Revenue Neutrality		

Preamble (if any):

BC Hydro has undertaken similar analysis recently with respect to optional Industrial rates, including pricing that incentivizes off-peak usage. Slide 41 of the following presentation calculates the long-run marginal cost of demand and energy for which to base revenue neutral rates ("economic efficiency") that provide long-term ratepayer benefit without impacting non-participating customers in the short-term: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/Presentation-Industrial-Optional-Rates-Workshop-2025-03-05.pdf

Question:

a) Is Mr. Friesen aware of, or undertaken, any analysis with respect to Manitoba Hydro's long-term marginal cost of capacity to support consideration for demand response-type rate development on a revenue neutral basis benefitting both participants and utility (similar to provided above for BC Hydro)?

b) If so, are there quantifiable potential long-term ratepayer savings as a result of the definitional changes to GSL class billing demand? Please provide.

Rationale for Question:

Response:

a)

Outside of regulatory filings, Mr. Friesen has not been informed of Manitoba Hydro analysis pertaining to long-term marginal cost of capacity and how such analysis may support considerations for demand response programs.

In reference to Slide 41, average embedded costs applicable to each rate class are available from PCOSS26. Table A2 [Appendix 7.1, PDF p. 15] provides an indication of embedded units cost applicable to capacity and energy requirements for General Service demand customers.

IR Responses referencing marginal values in this proceeding, include:

- PUB/MH I-75b indicates that marginal costs have been below embedded costs in recent years.
- PUB/MH I-82a indicates an equivalent annualized cost of capacity provided to the PUB in February 2025 based on a P80 confidence level equal to $168/kW-yr but then states that is use for setting marginal value for capacity in a curtailable rate environment is not appropriate.
- Coalition/MH I-130a includes a table of combined 30 Year Levelized Marginal Values categorized by generation, transmission, and distribution. While marginal values for capacity and energy applicable to generation are redacted, marginal values for transmission and distribution capacity are provided.
- Coalition/MH I-130b includes combined 30 Year Levelized Marginal Values for 2024/25 for generation, transmission, and distribution with cited limitations for comparison and use.
- MIPUG/MH I-42a provides combined 30 Year Levelized Marginal Values from 2017/18 thru 2024/25 categorizes by generation, transmission, and distribution. A breakdown of marginal values for capacity and energy over that period was redacted. Manitoba Hydro indicated that it had not undertaken analysis of on-peak and off-peak marginal values and confirmed that it did not apply geographic distinction to marginal values within the province.
- MPUG/MH I-23a includes the “Demand Response Strategy and Road Map for Manitoba” does not refer to specific marginal values in its evaluation of benefits.

b)

Manitoba Hydro’s response to MIPUG/MH II-15 pertaining to the impact of the change in Definition for Billing Demand indicates that capacity requirements among GSL >30 kV customers have a reduced annual on-peak capacity requirement relative to off-peak period of approximately 1.6% based on billing demand determinants.

Fiscal Year	On-Peak Greater	On-Peak Demand	Off-Peak Demand	On-Peak %	Off-Peak Greater	On-Peak Demand	Off-Peak Demand	On-Peak %	Total	On-Peak Demand	Off-Peak Demand	On-Peak %
20/21	16	865,994	863,144	0.33%	46	9,180,767	9,403,574	-2.43%	62	10,046,761	10,266,718	-2.19%
21/22	14	718,910	711,578	1.02%	47	9,772,922	9,952,954	-1.84%	61	10,491,832	10,664,532	-1.65%
22/23	23	2,415,776	2,407,885	0.33%	39	8,038,183	8,176,759	-1.72%	62	10,453,959	10,584,644	-1.25%
23/24	16	3,342,444	3,338,171	0.13%	47	6,347,257	6,495,194	-2.33%	63	9,689,701	9,833,365	-1.48%
24/25	15	1,506,739	1,495,922	0.72%	51	8,580,045	8,747,781	-1.95%	66	10,086,784	10,243,703	-1.56%
5 Yr Total	**84**	**8,849,863**	**8,816,700**	**0.37%**	**230**	**41,919,174**	**42,776,262**	**-2.04%**	**314**	**50,769,037**	**51,592,962**	**-1.62%**

Manitoba Hydro’s 2022/23 Load Research Report [Appendix 4.2, Table 4.2) and subsequent 2023/24 update [Coalition/MH I-143] indicates a winter coincident peak capacity requirement for the GSL subclasses that averages 14 – 30% lower than the coincident off-peak requirement for these subclasses.

	2022/23 (Appendix 4.2, Table 4.2)			2023/24 (Coaltion I-143, Table 4.2)		
Rate Category	Coincident Peak	Non-Coincident Peak	On-Peak %	Coincident Peak	Non-Coincident Peak	On-Peak %
Street and Sentinal Lighting	1,045	15,677	-93%	15,433	15,433	0%
Residential Basic - Other	492,496	649,497	-24%	577,984	612,103	-6%
Residential Basic - Electric	1,307,715	1,360,833	-4%	1,293,219	1,392,633	-7%
GS Small Non-Demand	259,029	281,831	-8%	314,102	365,357	-14%
GS Small Demand	498,089	509,034	-2%	370,923	464,337	-20%
GS Medium	526,075	535,783	-2%	492,921	547,932	-10%
GSL Large 750 V - 30 kV	175,357	240,248	-27%	249,836	278,564	-10%
GSL Large 30 - 100 kV Curtailable	24,786	25,007	-1%	24,924	48,075	-48%
GSL Large 30 - 100 kV	233,870	267,671	-13%	185,436	274,762	-33%
GSL Large >100 kV Curtailable	215,326	243,813	-12%	137,838	214,746	-36%
GSL Large >100 kV	448,742	536,837	-16%	333,827	458,893	-27%

MIPUG members have initiated requests for consultations and engagement on the potential value of demand response programming and other alternative rate options, citing examples of such programming and rate options in other jurisdictions. To date, Manitoba Hydro has provided limited information related the potential value to ratepayers of alternative rate propositions.

Detailed information pertaining to the value of load flexibility on the Manitoba Hydro system is lacking. Recent studies by Dunsky provided in response to information requests highlight significant potential capacity savings but no information is provided on long-term marginal value.

The historic 30 Year Levelized Margin Values from the MIPUG/MH I-42a response may not be appropriate for demand response given the combined capacity and energy value and assumed load factors used in the determination of those values. References to capacity marginal values in that response are redacted and therefore not generally available for valuation purposes.

GSS-GSM/MIPUG-11

Part and Chapter:	Evidence of Dale Friesen	**Page #:**	Section 4.0, page 4-4
Topic:	Distribution Reliability		
Subtopic:			

Preamble (if any):

Mr. Friesen concludes based on Figures 4.3 and 4.4 for Distribution outages:

> The upward trends in both duration and frequency are concerning as they indicate that the distribution system is experiencing a greater rate of degradation than the transmission system. SAIDI and SAIFI indices for the distribution system show nearly twice the frequency and duration of outages when compared to the transmission system.

Manitoba Hydro started increasing its distribution-related vegetation management spending, as shown in response to GSS-GSM/MH I-1(a) from $12.6 million in F2022 to $18.9 million in F2025 (approx. 50% cumulative increase over this time).

Question:

a) Is it possible that conclusions based on a long-term trend line will overlook near-term improvements (and potential forecast improvements) as a result of recent year increases to distribution vegetation management spend? Please explain.

b) Are there varying levels of reliability requirements that may be reasonable to consider between distribution level ratepayers (residential, small commercial, etc.) and larger distribution and transmission connected customers (large industrial)? Please explain.

Rationale for Question:

Response:

a)

The suggestion that trends based on historical actions and events may not adequately reflect future actions, planned or unplanned is not unreasonable.

Per Manitoba Hydro's filings, vegetation contacts account for 24% of outages on the overhead distribution system [Coalition/MH I-47a]. It would appear reasonable to suggest that an effective and efficient vegetation management program should improve reliability performance on a portion of the distribution system.

b)

Consumers across different rate classes may have differing sensitivities and outcomes from varying levels of reliability performance. Similarly, customers within individual rate classes may also have different experiences.

Industrial processes are often sensitive to momentary interruptions and outages, which have direct implications to costs in terms of lost and out-of-spec production, equipment damage, labour inefficiencies, etc. Longer duration outages typically included within SAIFI and SAIDI indices may also have varying impacts, related to lost income, costs for unproductive labour, lost production, and other factors that may be cited by industrial and commercial customers.

Some residential and commercial customers may view reliability events more as an inconvenience than a cost, particularly if those events are limited to shorter duration outages that do not create material risk for damage to homes, businesses, appliances, or food supplies. This perception may vary based on the frequency and duration of outages. Those working from home may experience greater sensitivity than those working from the office. Power quality events that are damaging to appliances and other equipment can create material costs for customers. Commercial enterprises would also be expected to have sensitivity to lost income, lost data, and labour inefficiencies arising through outages.

Reliability events create costs and inconvenience for consumers, regardless of rate class and activity. Effective metrics quantifying those unplanned costs support reasonable discussions about acceptable or desired levels of performance. Comparisons to national or regional levels of performance, while insightful, often fail to address core rationale related to assessments of benefits and costs for spending to improve reliability performance.

GSS-GSM/MIPUG-12

Part and Chapter:	Evidence of Dale Friesen	**Page #:**	Section 5.7, page 5-11
Topic:	GSL 0-30kV segmentation		
Subtopic:			

Preamble (if any):

With respect to the GSL 0-30kV class segmentation study that:

> The opportunity exists for Manitoba Hydro to develop a process by which larger GSL 750 V – 30 kV customers, that better suited to sub-transmission level service, may pay directly for dedicated Manitoba Hydro-owned distribution equipment used to connect their facility to the sub-transmission or transmission system. Their energy and capacity charges would then be based on the higher voltage sub-transmission rates for 30 – 100 kV customers, which are more representative of the costs that these customers impose on the generation and transmission system.

Question:

a) If the above subtransmission level direct payment conclusion is implemented, is Mr. Friesen proposing it be developed on a revenue neutral basis? Please explain.

Rationale for Question:

Response:

a)

Manitoba Hydro has not provided an analysis of potential options or methods for allocating costs for distribution facilities to large GSL 750 V – 30 kV customers served by dedicated facilities. MIPUG is seeking dialogue and engagement on this opportunity.

At present, distribution plant costs are classified as 100% demand with large GSL 750 V – 30 kV customers allocated a portion of costs for substations, poles and wires, etc. based on their contribution to non-coincident distribution system peak demand. The opportunity described in evidence requests consideration for direct allocation of distribution plant costs to large GSL 750 V – 30 kV customers served through dedicated distribution facilities.

Under the proposed scenario, energy and capacity charges would be determined based on allocations for the GSL 30 – 100 kV subclass. Determinants used for allocations of energy and demand costs in the sub-transmission class would increase by the energy and coincident peak demand determinants associated with large GSL 750 V – 30 kV customers that receive direct allocations of distribution plant costs, ensuring that their imposed costs are reflected in rates charged for demand and energy. Adopting this approach for large GSL 750 kV – 30 kV customers served from dedicated facilities would ensure that rates are based on costs imposed on the Manitoba Hydro system by these customers.