PUB/MIPUG I-1

Part and Chapter:	InterGroup Evidence p.9 Comparison of Long-Term Forecasts	Page No.:	
Topic:			
Sub Topic:			

PREAMBLE TO IR:

In his evidence on page 9, Mr. Bowman provides Table 2-1 comparing long-term forecasts:

Table 2-1: Comparison of Current and Previous Long-Term Forecasts

	Long Term Rate Increase	25% Equity Ratio	Maximum Long-Term Debt	Minimum Equity	Negative Net Income	Retained Earnings at 2033/34	Maximum Net Debt
NFAT Plan 5 – High Keeyask Level 2 DSM	3.95% 2014/15; 3.99% 2015/16 to 2031/32	2031/32	$22.490 B in 2023/24	8% in 2021/22-2023/24	Total of $638 M in 8 years during 2015/16 – 2022/23	$6.659 B	$21.606 B in 2022/23

QUESTION:

a) Considering NFAT Plan 5 included a 300MW export sale to Wisconsin Public Service which was contingent upon Conawapa, and which has since been terminated, please confirm whether a comparison to NFAT Plan 6 is a more appropriate comparator.

b) If confirmed, please re-file Table 2-1 using the NFAT Plan 6 financial details.

RESPONSE:

a)

NFAT Plans 5 and 6 were generally very comparable through most of the years in question, though Plan 6 had a slightly larger exposure to energy price swings. Unfortunately, throughout the proceeding, the two Plans were often not both updated for new information. The cited Table was prepared by Hydro in the 2017/18 GRA, based on requests by MIPUG, reflecting that Plan 5 data was available for scenarios that unfolded during the proceeding (the addition of Level 2 DSM in particular) as part of the various subparts of Exhibits 104-12.

Given the above table uses Reference conditions (not low or high export market conditions), Plan 6 would have likely been quite similar.

It is also debatable that, with the passage of time, Plan 6 is indeed a closer representation of the conditions that arose. Plan 6 was based on supply conditions that would have not required new resources until 2037 (NFAT Ex. MH-192), while present estimates are for a need date of 2030/31 (Application, Tab 5, page 36).

Given Hydro's confirmation that they view Plan 5 as a reasonable portrayal of the expectations at the time the NFAT was approved (See MIPUG/MH-I-2f from the 2017 GRA), it seems appropriate to compare to the available Plan 5 values shown in the above table.

b)

See a).

Also note that the same projections do not appear to have been made available for Plan 6 from the NFAT proceeding record.

PUB/MIPUG I-2

Part and Chapter:	InterGroup Evidence p. 14 O&A Expenses	Page No.:	
PUB Approved Issue No.:			
Topic:			
Sub Topic:			

PREAMBLE TO IR:

At p. 14 of his evidence, Mr. Bowman states:

> Hydro's performance could improve significantly with aggressive cost control in the areas of O&M and sustaining capital, assuming these can be achieved without further erosion in Hydro's system reliability and customer service performance.

QUESTION:

a) Please explain whether Mr. Bowman has any recommendations on the level of O&A and business operations capital for the test periods different than what is proposed by Manitoba Hydro. If so, please provide Mr. Bowman's recommendation(s) and any supporting analysis.

b) Please comment on the recommendations made by GSS/GSM witness Mr. Madsen on O&A expense for the test years in this regard.

RESPONSE:

a)

Mr. Bowman's primary focus in this rate application was not on O&M spending, as these areas were coordinated with the GSS/GSM and Coalition witness to be in the lead.

b)

Mr. Madsen's submission in respect of O&M expenses reflects his extensive experience within utilities, and in reviewing the accounting and budgeting performance of regulated utilities. Mr. Bowman has not worked within a utility, nor been deeply involved in the preparation of budgets from the ground up. For this reason, Mr. Madsen's recommendations merit careful attention beyond any detailed commentary Mr. Bowman can provide.

Second, Mr. Bowman notes Mr. Madsen's recommendations in the area of labour costs are framed as being effectively subservient to the requirements to "support continued reliability". Mr. Bowman echoes this overarching objective. In cases where reductions to labour or O&M (or sustaining capital) may lead to decreases in reliability, the outcomes would be harmful to customers, not beneficial. Mr. Madsen draws some conclusions on reliability from the SAIDI and SAIFI data provided by Hydro; however, caution is likely merited as SAIDI and SAIFI do not capture short interruptions such as momentary (MAIFI), and in many cases these short interruptions can be very costly to customers.

However, Mr. Madsen (and similarly Mr. Rainkie for the Coalition) provide detailed and insightful commentary regarding non-operational positions that have seen high degrees of growth, in areas such as the President's office, and Human Resources (e.g., see Madsen submission, page 76) which would not appear to be driven by reliability. On these matters, Mr. Madsen's (and Mr. Rainkie's) evidence merits careful review as it highlights issues that should be a kay concern for the Board.

PUB/MIPUG I-3

Part and Chapter:	**InterGroup Evidence p.18 Spacing of Rate Increases**	**Page No.:**	
PUB Approved Issue No.:			
Topic:			
Sub Topic:			

PREAMBLE TO IR:

In his evidence on page 18, Mr. Bowman states:

> Recommendation 2: The Board may want to consider delaying the April 1, 2024 increase to September 1, 2024, to help mitigate the impact of multiple rate increases within the same 12 month period.

QUESTION:

a) Since the Manitoba Hydro Amendment Act (Bill 36) implies a rate increase on April 1, 2025, does adjusting the 2024 rate increase simply move the issue of multiple rate increases within the same 12 months period to the following year?

b) Please explain the importance of spacing the 2023 and 2024 rate increases by 12 months considering there will not have been a rate increase for 16 months prior to the September 1, 2023 rate increase?

RESPONSE:

a)

Mr. Bowman is not a lawyer. However, it would appear the Manitoba Hydro Amendment Act indicates a rate period starts on April 1, 2025, but there does not appear to be any commentary for or against rate changes occurring at any time during a rate period, whether April 1 or some other date. The definition of rate period appears more akin to Test Year, than to the strict date for rate changes.

b)

Mr. Bowman acknowledges that rate impacts occur at varying time periods, at times longer than 12 months, and on occasion shorter. The history of Manitoba Hydro rate increases shown in Tab 10, MFR 18 (Amended) Figure 1 indicates 5 instances in the last 25 years where the period between rate increases was less than 12 months (April 1, 2005; April 1, 2009; Sept 1, 2012; May 1, 2013; June 1, 2018). Despite this occasional occurrence, stability and predictability in rates remains a valid and important rate setting objective. Customers, particularly businesses and industries, need to schedule and budget for production, and power costs are an important input to these decisions. The benefits of a few months of expedited rate increases are limited in the long-term, while the impacts can be material and adverse for customers.

For this reason, many jurisdictions and regulators avoid, where possible, multiple rate changes within a 12 month period.

PUB/MIPUG I-4

Part and Chapter:	**InterGroup Evidence p.18 Spacing of Rate Increases**	**Page No.:**	
PUB Approved Issue No.:			
Topic:			
Sub Topic:			

PREAMBLE TO IR:

In his evidence on page 18, Mr. Bowman states:

> In summary, based on three factors noted above, Hydro's proposal to implement an overall rate increase of 2% in each of 2023/24 and 2024/25 appears prudent and reasonable. The same logic also suggests any roll-back of the 3.6% rate increase from January 1, 2022 would undermine progress towards the same overall objective. The three key factors are:
>
> > 1) Limits imposed by Bill 36 on Hydro's ability in the future to raise revenue through above-inflation rate increases if required as part of rate response to adverse developments (e.g., further interest rate increases).
> >
> > 2) Dependable export contracts that are scheduled to end in 2025/26.
> >
> > 3) Required refinancing of low cost debt in 2026/27 to 2028/29.

QUESTION:

Please confirm whether Mr. Bowman's analysis in support of finalizing the 3.6% interim rate increase exactly mirrors his analysis in support of the 2% rate increases in the test years. If not confirmed, please explain what other factors support the finalization of the 3.6% interim rate increase.

RESPONSE:

Support for the 3.6% interim rate increase is predicated on the fact that any reduction in the interim rate increase will simply lower the financial trajectory going forward. This would serve to offset or negate the financial benefits of the 2% rate increases proposed.

If it was determined that the 3.6% increase is not merited, the board is left with 3 options. First, it can impose a refund for past amounts paid. Second, it can make a simple downward adjustment in the 2% otherwise sought for 2023/24. Of the two options, the latter is far more preferable from a logistics viewpoint. However, the former may be more favourable from a communication standpoint, to draw the clear linkage that an interim rate, predicated on a set of facts (e.g., drought, a given level of government charges) will not be upheld if facts change.

Third, and potentially the best outcome, is for the Board to retain the 3.6% rate increase, but to adjust the revenue requirement in 2022/23 (or even 2023/24 if that is the only year available) by ensuring that the added amounts paid by customers, which were ultimately not necessary, can be put to use for long-term benefits to customers. This is in part a justification for Mr. Bowman's recommendation #4 to make use of a portion of the extra revenue from the interim rate increase to eliminate deferred cost items that would otherwise burden future ratepayers (i.e., Conawapa planning costs and losses on disposal and salvage of discontinued operations).

PUB/MIPUG I-5

Part and Chapter:	**InterGroup Evidence p.18 Interim 3.6% Rate Increase**	**Page No.:**	
PUB Approved Issue No.:			
Topic:			
Sub Topic:			

PREAMBLE TO IR:

Preamble:

In his evidence on page 19, Mr. Bowman states:

> However, with Hydro failing to update the uncertainty analysis tool, and with the new limits on rate increases above inflation, the potential to explore rate increases today below the proposed level is not possible. Notwithstanding the Bill 36 limits on rate response, resumption of work on this analytical product should be prioritized, in support of providing an advanced tool for assessing the likelihood of reaching mandated financial ratios by legislated target dates under specified conditions, rather than simply relying on deterministic scenario modelling.

QUESTION:

Considering the rate cap and debt-to-capitalization ratios imposed by the Manitoba Hydro Amendment Act (Bill 36) and the expected prescriptive nature of rate increases, please elaborate on the usefulness of the uncertainty analysis.

RESPONSE:

The rate setting framework under Bill 36 provides for a long-term target of 80% by March 31, 2035, and 70% by March 31, 2040. The Board is directed to approve rates (subject to other conditions) that are projected to achieve these targets (unless amended by regulation). Some of the other objectives are that rates should be stable and predictable from year to year, and there is a maximum increase tied to inflation.

Any projection contains a degree of forecast uncertainty. The Board would not be well served by considering only a single forecast in determining if it were on the appropriate path, and without knowing the risks that the actual performance may cause the financial outcomes to vary from by the path.

Uncertainty analysis can assist the Board in knowing the sensitivities inherent in the baseline forecast. For example, how sensitive is the forecast to interest rates versus export prices? How big an impact arises with floods or droughts? These matters can be tested by deterministic scenario analysis, but are much better modelled using probabilistic tools, as outlined in Mr. Bowman’s Background paper from the 2017 GRA (Exhibit MIPUG-15, Background Paper C).

It is acknowledged that the uncertainty analysis would be of even more use in a situation where it helps guide the setting of the financial target, rather than the highly inferior approach now adopted in legislation where the target is set prescriptively by legislation without evidence in support.

PUB/MIPUG I-6

Part and Chapter:	**InterGroup Evidence p.21; Order 59/18 pp. 148-149 Regulatory Deferrals**	**Page No.:**	
PUB Approved Issue No.:			
Topic:			
Sub Topic:			

PREAMBLE TO IR:

Pages 148-149 of Order 59/18 state:

> Manitoba Hydro proposes that the costs pertaining to the construction of Conawapa be recorded in a regulatory deferral account effective March 2018, with amortization of the costs to income on a straight-line basis over a period of 30 years beginning on April 1, 2018. […]
>
> The only Intervener to take a position on Conawapa costs was the Consumers Coalition, which accepts Manitoba Hydro's proposed treatment. […]
>
> The Board accepts Manitoba Hydro's proposed treatment of the Conawapa costs. This treatment is appropriate because the decision to discontinue Conawapa construction was part of the NFAT review of the Utility's long-term system planning for long-lived assets. Further, this approach smooths out the impact of this one-time cost on consumers.

QUESTION:

Please comment on how writing off the Conawapa regulatory balance impacts the concept of regulatory certainty based on the prior Board decision to establish the Conawapa deferral account at that time.

RESPONSE:

A decision to accelerate amortization of the Conawapa planning costs to one-year, matched with recognition that this component of revenue requirement is funded from revenues (including the interim rates) in the test year indicated (ideally 2022/23) is a simple example of the Board managing the regulatory accounts it created.

It is important to keep focused on the matching of the account amortization with the revenues to fund the amortization. Regulatory certainty would not be undermined in cases where the utility achieves better certainty, as would be the case in this situation.

If the utility has doubts as to whether future revenues will arise to pay for deferred costs, then regulatory uncertainty will be a problem. In this case, the revenues were already provided in 2022/23 (giving rise to otherwise record net income). Accelerating amortization <u>when matched with revenues</u> is not an undermining of regulatory certainty, it is if anything reducing regulatory uncertainty since the utility now has the cash, rather than waiting another 25 years to find out if it will in fact recover the cash.

PUB/MIPUG I-7

Part and Chapter:	**InterGroup Evidence p.31; Depreciation**	**Page No.:**	
PUB Approved Issue No.:			
Topic:			
Sub Topic:			

PREAMBLE TO IR:

At p. 31 of his evidence, Mr. Bowman indicates that the recognition of a loss to net income or to a regulatory deferral account and amortize it over the life of the asset "*is to pancake a second method of addressing purported gains and losses on top of the already internally consistent ASL approach. No other utility which uses ASL that I am aware of attempts to short-circuit or pancake such a methodology as a regulatory deferral on top of the ASL procedure, which is already achieving the same objective.*"

QUESTION:

a) Please provide a description of the accounting followed for other regulated utilities using ASL in addressing interim losses and compare it with that proposed by Manitoba Hydro. Provide examples including those utilizing IFRS.

b) Please explain the relevance in the Canadian context of the NARUC's determination of accounting for losses as a charge against accumulated depreciation consistent with U.S. GAAP and contrast the accounting approach prescribed under IFRS, which would appear to require a regulatory account treatment under IFRS 14.

RESPONSE:

a) and b)

A typical practice for utilities using group depreciation, regardless as to accounting standard or group procedure, is to dispose of assets through an equal adjustment to gross plant and accumulated depreciation at the time of disposal, except in very rare circumstances. For just one example, consider the Ontario Energy Board "Uniform System of Accounts for Gas Utilities"[1] which notes:

> 105. ACCUMULATED DEPRECIATION -- UTILITY PLANT This account shall be credited with current depreciation expense of the company's utility plant, which is concurrently debited to Account No. 303, "Depreciation", and with any salvage and insurance proceeds from the disposal of depreciable utility plant. At the time of retirement of depreciable utility plant, this account shall be debited with the book value of the plant and the cost of removal, and credited with amounts recovered for salvage and insurance. Note: See Plant Accounting Instructions, Appendix A, Section 3, "Retirements".

Appendix A Retirements indicates:

> When the retirement or disposal of any individual asset in a group occurs under circumstances reasonably provided for through accumulated depreciation, it may be assumed such provision has been made. Thus, whether the period of service life is shorter or longer than the average service life, accumulated depreciation attributable to an asset at the time of retirement under such circumstances is equal to the cost, except for that portion reasonably assumed to be recoverable through salvage realization. Assets remaining in use after reaching the average life expectancy are not regarded as fully depreciated until actual retirement. (emphasis added)

Nowhere in this system of accounts are the terms ASL or ELG mentioned. This is only a single example, but defines the traditional practice for group asset management that has been in place for decades and remains extremely common throughout North America.

The question however is about relevance of this technique to Canadian utilities, which is presumed to mean relevance to rate-setting.

The relevance of the Canadian context is that each of the regulators normally have very similar legislative mandates – to ensure rates are just and reasonable. The mandates of regulators are not to chase interpretations of accounting standards (whether these are fixed or subject to ongoing interpretations). Rate setting on the basis of interpreting accounting standards is inappropriate in that it fails to begin with the clear legislative mandate given a regulator, and it is also contrary to the purpose of the two roles.

The role of a regulator is prospective. It is to establish the rates to be charged in the future. As such it sets the economic and financial conditions within which a utility operates. And

[1] https://www.oeb.ca/sites/default/files/uploads/documents/regulatorycodes/2019-01/Uniform-System-of-Accounts-for-Class-A-Gas-Utilities.pdf

through control of revenues, it is a material factor in the context within which a utility operates.

The accounting standards are retrospective. As noted in the description of IAS 1:

> The application of IFRS Standards, with additional disclosure when necessary, is presumed to result in financial statements that achieve a fair presentation.

The purpose of the standards is fair presentation. It is to portray a financial condition of an organization, after the fact.

A classic example is Demand Side Management costs. In the first instance, these amounts are spent, and a regulator determines how and when these costs can be recovered (i.e., generate revenues) for a utility. If this amount is in the future, then it represents an entitlement of the utility to revenues underpinned by the decision of a regulator.

For the parties required to then report on the financial condition of the utility, they face a decision. On a normal basis, DSM spending is difficult to recognize as an asset – e.g., a utility buying an LED light bulb and giving it to a customer does not create anything the utility owns, or can monetize, nor does the utility control access to the benefits, nor can they guarantee its continued use. This is unlikely, on its own, to be recognized as an asset under any financial reporting structure.

However, the actions of the regulator can create an asset – a promise of future revenues tied to the amount spent (whether for the LED light bulb or any other items). The individuals responsible for financial reporting may or may not determine that this promise from the regulator of future revenues is sufficient to permit recognition of an asset.

But this determination as to whether there is an asset or not does not change the role of the regulator at all – the regulator needs to determine (by legislative mandate) if the spending is appropriately recovered from ratepayers, and when. It must do so to convince itself that rates are just and reasonable. Most regulators will view that rates are just and reasonable when a utility spending on an LED light bulb that reduces its need to spend on a new generator or distribution upgrade is matched with the time period in which that benefit will arise – not all in year 1 but spread over many years.

IFRS does not indicate how an entity must act or how a regulator must regulate. It is there to determine how an entity must present the situation given the economic, financial, regulatory, etc. conditions that the entity faced at the given point in time, including the decisions of its rate regulator. And one of the most important conditions it must assess (though not necessarily accept) is what the regulator determined in setting the entitlement to revenues.

In the context of depreciation, the same issues arise with respect to the notional gains and losses. It is a well-established principle of depreciation (whether under ELG or ASL, and whether under CGAAP or US GAAP or IFRS) that setting a depreciable life for a group of assets will not perfectly match the dispersion of the asset retirements. It is also inherent to the depreciation expense that is calculated under any approach that the group will be depreciated over the expected life of the group. An ASL approach best matches the idea that the service value received by the customers should be spread across the service value provided by the group of assets.

If a regulator says it accepts ASL as the methodology, with longstanding accounting approaches to adjusting accumulated depreciation for the gross book value at the time of all disposals, it has created the entitlement to revenues matching that method. After this decision, three outcomes may occur: (i) the auditor may accept this approach, or (ii) may not accept that this practice is acceptable for financial reporting purposes, but still accept that this regulatory decision creates an entitlement to future revenues and permit the creation of a regulatory deferral that gives the same outcome. However, if the auditor accepts none of these paths, then (iii) the auditor may require gains and losses to be recorded in net income and retained earnings in the year experienced. Regardless as to which decision the auditor makes, this decision is not reasonable to apply as a circular input into the regulators decision as to what constitutes just and reasonable rates under the law.

Finally, Mr. Bowman notes that the quote in the preamble from the pre-filed testimony could be taken out of context. Mr. Bowman recommends that the Board set rates based on ASL (with appropriate componentization) and that Hydro calculate depreciation on the basis that gains and losses are part of accumulated depreciation. If this mathematical outcome is achieved by way of the traditional approach to crediting accumulated depreciation for the full gross plant value of all disposals (approach (i)), then the two sets of books will match. If not, and the same mathematical outcome is achieved by maintaining a gains and losses deferral accounts that is amortized over the remaining life of the assets in the account (approach (ii)), and for all intents and purposes the balance is treated as accumulated depreciation (particularly for the purposes of performing a depreciation study), then the exact same outcome will be achieved.

However, even if the third outcome arises, and the gains and losses must be taken to income each year, this is no justification for the regulator to reject their earlier conclusion on what constitutes just and reasonable rates.

This is why the actions of regulators throughout the continent, who share a goal and usually a mandate of regulating in the public interest, are of relevance.

PUB/MIPUG I-8

Part and Chapter:	**InterGroup Evidence pp. 44, 45; Tab 8 pp.7, 9, Appendix 8.1 p.18 Incorporating Net Export Revenue into RCC Ratio Calculation**	**Page No.:**	
PUB Approved Issue No.:			
Topic:			
Sub Topic:			

PREAMBLE TO IR:

In his evidence on page 45, Mr. Bowman states:

> Hydro has indicated that the approach to export revenue allocation is a major change in the PCOSS24 RCC ratios, as indicated in the third column from the following table (re: Directive 27) taken from the Application[100]:
>
> Footnote 100: Hydro Application, Tab 8, page 8.

In his evidence on page 45, Mr. Bowman provides a table comparing RCC ratios with different treatments of net export revenue:

Table 4-1: Comparison of Export Revenue Treatment Approaches

$millions

		Costs		Revenues	Surplus/(Shortfall)	RCC ratio
Offset Approach		$1,352.4				
(approved)	less:	$471.2				
	total	$881.2		$831.6	$49.6	94.4%
Revenue Approach				$831.6		
(previous)			plus:	$471.2		
		$1,352.4	total	$1,302.8	$49.6	96.3%

In Tab 8 on page 7, MH states:

Manitoba Hydro's PCOSS methodology underwent an extensive public review in 2016. The subsequent order from the PUB (Order 164/16) directed the majority of the underlying methodology used in Manitoba Hydro's current study. Further refinements were directed in Order 59/18, which have been reflected in PCOSS24 and are discussed in greater detail in Appendix 8.1. These directives include:

- Directive 27 - Net Export Revenue is treated as a reduction of class cost, rather than as an addition to class revenue in the RCC calculation.

In Appendix 8.1, MH provides the PCOSS24 summary table on page 18, showing the calculation of RCC ratios using Net Cost, which is the Total Cost less Net Export Revenue:

Customer Class	Total Cost ($ million)	Class Revenue ($ million)	RCC % Prior to NER	Net Export Revenue ($ million)	Net Cost ($ million)	RCC % Current Rates
Residential	1,352.4	831.6	61.5%	471.2	881.2	94.4%
General Service - Small Non Demand	298.7	210.3	70.4%	106.9	191.8	109.7%
General Service - Small Demand	234.9	150.7	64.2%	86.9	148.0	101.8%
General Service - Medium	378.9	235.6	62.2%	144.0	235.0	100.3%
General Service - Large 0 - 30kV	214.8	125.0	58.2%	87.2	127.6	97.9%
General Service - Large 30-100kV	177.5	107.0	60.3%	82.3	95.2	112.4%
General Service - Large >100kV	282.0	166.6	59.1%	134.8	147.2	113.2%
SEP	2.8	3.0	106.2%	-	2.8	106.2%
Area & Roadway Lighting	27.6	26.7	96.6%	3.0	24.7	108.2%
Total General Consumers	2,969.7	1,856.6	62.5%	1,116.2	1,853.5	100.2%
Diesel	13.0	9.9	76.4%	-	13.0	76.4%
Export	37.9	1,154.1	3043.8%	(1,116.2)	1,154.1	100.0%
Total System	3,020.6	3,020.6	100.0%	-	3,020.6	100.0%

In Tab 8 on page 9, MH provides a table of RCC results:

Figure 8.3 PCOSS24 RCC Results Compared to RCC Results of PCOSS21

Customer Class	PCOSS21 RCC		PCOSS24 RCC	
Residential	96.2%	In	94.4%	Below
General Service Small Non-Demand	113.8%	Above	109.7%	Above
General Service Small Demand	104.0%	In	101.8%	In
General Service Medium	99.3%	In	100.3%	In
General Service Large 750V-30kV	95.6%	In	97.9%	In
General Service Large 30-100kV	103.7%	In	112.4%	Above
General Service Large >100kV	101.2%	In	113.2%	Above
Area & Roadway Lighting	123.3%	Above	108.2%	Above

QUESTION:

a) Please confirm whether MH has correctly calculated the RCC ratios in the summary table in Appendix 8.1 on page 18 with Net Export Revenue as an offset to the costs allocated to each class, consistent with Order 59/18 Directive 27.

b) Please confirm whether the RCC ratios presented in Figure 8.3 from Tab 8 are calculated correctly with Net Export Revenue as an offset to the costs allocated to each class, consistent with Order 59/18 Directive 27.

RESPONSE:

a)

Confirmed

b)

Confirmed.

PUB/MIPUG I-9

Part and Chapter:	**InterGroup Evidence p.47 Normalizing PCOSS**	**Page No.:**	
Topic:			
Sub Topic:			

PREAMBLE TO IR:

Preamble:

In his evidence on page 47, Mr. Bowman states:

> It is noted that future PCOSS analyses may show different results owing to changes to water flows. Arguably, the PCOSS scenario could be normalized for water flow variances. However, this would open a substantial debate about which other factors are appropriate to normalize in preparing the PCOSS.

QUESTION:

What other factors does Mr. Bowman consider appropriate, or potentially appropriate, to normalize in preparing a PCOSS?

RESPONSE:

a)

None.

A PCOSS is a prospective measure of the costs and revenues for a year. So long as it is accurately reflecting a forecast year, it will be internally coherent and useful for measurement. There is no need to normalize the PCOSS because any single PCOSS will not be determinant for drastic impacts on customers the way rates are set in Manitoba (e.g., it will not lead to increasing a customer class by 5-10% in order to decrease a different class by 5-10%). These changes will occur over multiple PCOSS.

Were the PCOSS used to implement drastic rate changes, there could be a risk that one PCOSS could drive an overshoot of rate changes needed. As noted in PUB/MIPUG-I-13, there has never been such an overshoot occur in Manitoba.

PUB/MIPUG I-10

Part and Chapter:	**InterGroup Evidence p.48 Impact of 2024/25 NER on RCC Ratios**	**Page No.:**	
Topic:			
Sub Topic:			

PREAMBLE TO IR:

Preamble:

In his evidence on page 48, Mr. Bowman states:

> As noted in the above Table 4-2, the use of export revenues (and net income) normalized for water flows made no difference to which classes were above, below or within the ZOR. The RCC ratios moved to a degree, but it would be expected that Hydro's relative rate proposals would still be of relevance and be appropriate to retain under either scenario.

QUESTION:

If MH's rate differentiation proposals are based on moving classes into the zone of reasonableness over a set number of years, please explain whether different RCC ratios would affect the annual rate changes required. Put another way, if export revenues based on normal water flows cause the RCC ratios to change from those in PCOSS24, would the calculated rate changes required to move classes within the zone of reasonableness also change?

RESPONSE:

If the PCOSS ratios from Table 4-2, with the 2024/25 export revenues were used (i.e., what might be termed normalized water), it could drive a small difference in the rate adjustments otherwise calculated to meet the Board's directive to reach the outer ranges of the ZOR by 2027/28. However, Hydro is not anywhere near meeting this Board directive. The GSL >100 kV RCC is 113.2% (expected water) or 110.5% (adjusted water), and there are only 5 years left to reach the ZOR (105%). This means that the rate differential would need to be 1% below the average rate increase or greater under the adjusted water scenario (to drop from 110% to 105% in five years), and 1.6% or greater under the expected water scenario (to drop from 113% to 105% in five years).

Hydro has proposed an average 2% rate increase, and 1.5% for GSL >100kV. The current GRA GSL >100kV increase would need to be below 1% using the adjusted water, and below 0.4% using the expected water.

For this reason it is not material to assessing the rate proposal to use an adjustment for water, as there are still adjustments points for future PCOSS studies (Which could reflect any particular water condition, or other variances that may arise) before the 2027/28 target date is reached.

PUB/MIPUG I-11

Part and Chapter:	**InterGroup Evidence p. 51; Efficiency Manitoba 2020-2023 Efficiency Plan proceeding Transcript p.331 Marginal Value and Allocation of DSM Costs**	**Page No.:**	
Topic:			
Sub Topic:			

PREAMBLE TO IR:

Preamble:

In his evidence on page 51, Mr. Bowman states:

> The Board's finding in the EM [Efficiency Manitoba] proceeding follows the clear evidence of EM that the value of DSM is spread across all 3 functions, generation, transmission, and distribution. This is highlighted in the EM response to Daymark/EM I-20a from that proceeding, which notes:
>
>> Manitoba Hydro provides Efficiency Manitoba with a forecast of 30 years of generation, transmission, and distribution marginal values. The generation marginal values for each year are broken out between marginal energy values and marginal capacity values that are then each differentiated between summer and winter seasons. Transmission marginal values are forecast on the basis of winter capacity for each of the 30 years. Distribution marginal values are also forecast on the basis of winter capacity for each of the 30 years. [footnotes removed]

On page 331 of the January 6, 2020 transcript of the PUB's proceeding to review Efficiency Manitoba's 2020-2023 Efficiency Plan, the witness for Efficiency Manitoba explained:

With respect to the cost-effectiveness screening, our regulations require that we look at the cost-effectiveness at a portfolio level, so we were not looking to pre-screen out measures, individual measures or programs along the way. We wanted to see what the overall portfolio cost-effectiveness was.

QUESTION:

a) Please confirm whether it is in Efficiency Manitoba's mandate to reduce winter demand for electricity (as opposed to energy) in order to avoid MH investing in transmission and distribution assets.

b) If Efficiency Manitoba does not screen out any individual measures due to cost effectiveness, does this indicate that MH's marginal values do not have a significant or even marginal impact on the DSM measures implemented by Efficiency Manitoba?

c) If individual measures are not screened out for cost effectiveness, are the transmission and distribution components that the marginal value is comprised of irrelevant to Efficiency Manitoba's programming?

RESPONSE:

a)

There is no formal capacity target in Efficiency Manitoba's mandate at this time. However, when spending on conservation Efficiency Manitoba achieves peak demand reductions, and it uses the economic benefits of the peak demand reductions as part of the justification for running the amounts and types of programming that it does. Further, Hydro pays for and benefits from these peak demand reductions.

b)

No.

The quote references a pre-screening process for individual measures (e.g., solar swimming pool heaters). At that stage and at the level of measures, Efficiency Manitoba does not apply strict cost-efficiency thresholds. But later in that same transcript exchange Efficiency Manitoba explains that its mandate is to achieve cost effectiveness at the portfolio level as measured by the Program Administrator Cost Test (PACT) (e.g., page 349). Efficiency Manitoba notes that some individual measures will not be strictly cost-effective (e.g., low income programs) but these are included in a portfolio to meet the EM mandate. This is why cost effectiveness is not screened on a measure-by-measure level.

However, as a group, the portfolio is cost effective, when measured against the utility costs. Those utility costs include the benefits of avoided demand/capacity investment based on the marginal value of that capacity.

c)

No, they are not irrelevant. Additionally, if the conclusion is that they are irrelevant, then it is not clear why generation would be relevant.

It is important to recall that in the 2016 COS review MIPUG and Hydro argued that DSM measures should be assigned to the customer class, rather than the system, because the primary beneficiary of many aspects of DSM spending is the customer class (either through reduced loads that lead to lower allocated costs, or through non-energy benefits like more comfortable homes or better lighting quality, etc). The Board concluded that the important benefits of DSM instead relate to the system benefits in terms of avoided costs. At this level of logic, there is no distinction between generation versus transmission or distribution – DSM benefits each, and in the exact same way, by deferring future investment.

PUB/MIPUG I-12

Part and Chapter:	**InterGroup Evidence p. 54**	**Page No.:**	
Topic:			
Sub Topic:			

PREAMBLE TO IR:

Preamble:

In his evidence on page 54, Mr. Bowman states:

> Following the precedent of the Centra COS review, there would appear to be no good rationale for retaining the top 50 hour averaging approach in Hydro's COS. In addition, Hydro's GRA makes clear that capacity-related costs are an important and growing component of the price signals that need to be considered in setting a fair COS methodology.

QUESTION:

a) Please provide a table showing the proportion of hours in a year represented by Centra's peak day, the proportion of hours in a year represented by MH's coincident peak, the proportion of hours in a year represented by Mr. Bowman's proposal to use the top hour, and the proportion of hours in a year represented by Mr. Bowman's alternate proposal of four to six hours for the determination of the coincident peak.

b) Compare and comment on these proportions and explain whether Centra's peak includes averaging beyond a single peak hour.

c) Please explain whether MH's averaging of eight years of load data provides sufficient attenuation of any extraneous peak hours that could affect the calculation of the coincident peak.

RESPONSE:

a) and b)

Mr. Bowman is not aware that a Centra gas load duration curve was provided in the Centra COS review. For this reason, it is not possible to demonstrate how much the use of Centra's single peak day captures the many other days that may be near peak. During the peak day, the throughput will vary across the 24 hours, but the measure of peak day is directly linked to the scale of investment needed. If the peak day rises, a bigger system is needed. It would not be appropriate to average across the highest 10 days, since a system that can only meet the tenth highest day and no more (or the average of the ten days) will fail to serve customers.

For Hydro's electrical system, the top 50 hours obviously relates to a wide averaging of the peak across multiple hours comprising about 0.57% of the year (one hour is 0.011%; while 5 hours is 0.057%. This may appear small, but within these 50 hours are many hours where the use is much lower than the top hour (up to 200 MW or more variance based on 2020 system load duration curves, which is equal to the entire output of Wuskwatim). For an allocator that is intended to show responsibility for assets which are built to meet peak, the use in hour 50 (when the system is well below peak) is not relevant. The 50 hours are not contiguous – some are months apart, and the lowest are hundreds of MW (200+) below the peak hour. It is not relevant what customers are using during these more shoulder hours, as the 50th hour is not the load that drives investment – it is the peak hour.

Further, in the case of gas, there is a certain natural averaging over short periods, as the system can absorb small changes in pressure, line packing, etc. For electricity, the system must meet all loads in the same instant. Centra's use of peak day does include a small degree of averaging, but it is averaging that more is consistent with the physical infrastructure. For this reason, a focus on the top peak period (or very small number of hours) is more important in electricity than in natural gas distribution.

c)

Manitoba Hydro's use of eight years provides a significant degree of attenuation that could serve to provide all of the averaging needed to permit a proper 1CP (single hour peak from each year) to be used in the PCOSS. It would help avoid, for example, a year where the peak was at night and streetlights were on, driving a 100% coincidence factor for lighting, when in some years the peak may occur when the streetlights are off. If the streetlights are off 2 years in 8, then the 8-year averaging would help solve this allocation issue, without a need to use the top 50 hours.

PUB/MIPUG I-13

Part and Chapter:	**InterGroup Evidence p. 56 RCC Ratios and the Zone of Reasonableness**	**Page No.:**	
Topic:			
Sub Topic:			

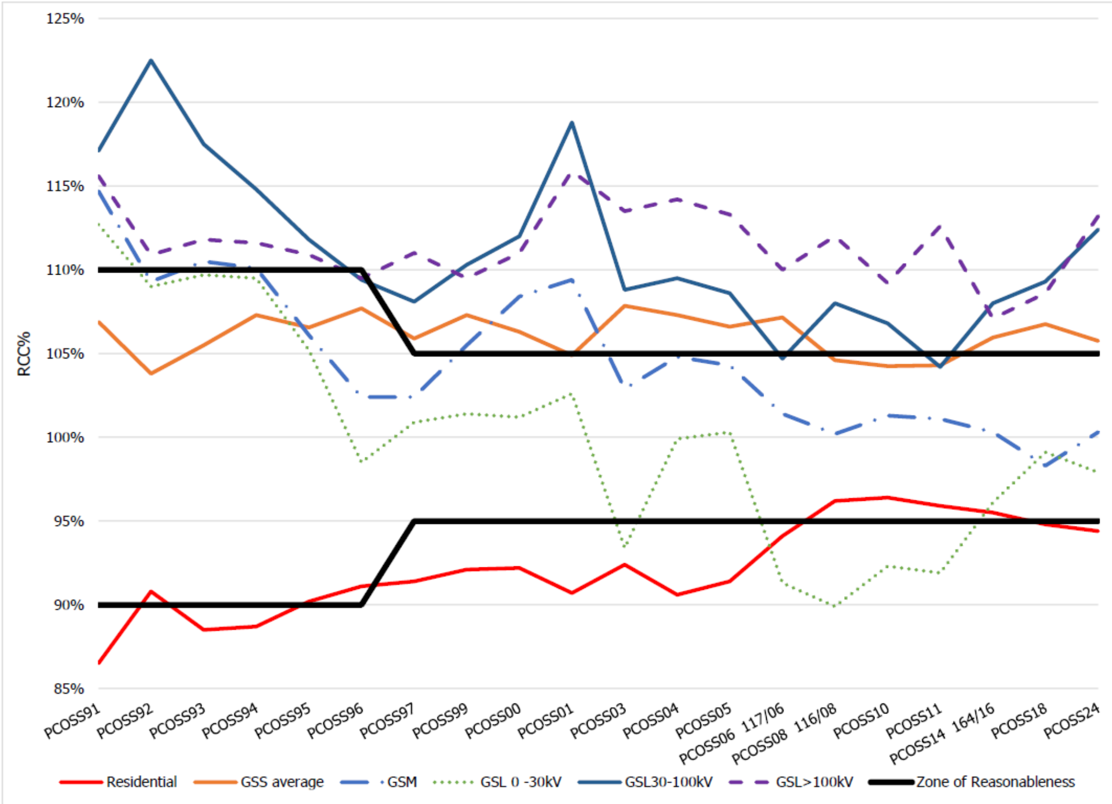
PREAMBLE TO IR:

Preamble:

In his evidence on page 56, Mr. Bowman states:

> Hydro's approach to COS has focused on classes that are above or below the ZOR, to attempt to bring these classes to the edge of the ZOR as a first priority. However, consistent with other rate design principles such as gradualism and avoiding rate shock, Hydro has tended to propose modest adjustments to rates rather than more significant adjustments to solve the ZOR issues more quickly. <u>This approach has been largely unsuccessful over many decades</u>, as shown in the below figure summarizing Hydro's approved PCOSS studies since 1991. [emphasis added]

Figure 4-1: Manitoba Hydro PCOSS RCC results since 1991



QUESTION:

a) For the years identified in Figure 4-1 of Mr. Bowman's evidence, please identify how many rate increases have been differentiated by customer class.

b) Please confirm which RCC ratios in Figure 4-1 (i.e., which PCOSS) are based on the Board's approved method of calculating the RCC ratios (net export revenue as an offset to allocated costs).

c) Please explain how reliable Mr. Bowman considers the PCOSSes giving rise to the RCCs in Fig 4-1 are, and how consistent these PCOSSes are with the Board's 2016 PCOSS methodology.

RESPONSE:

a)

From approximately the beginning of the chart (1991) until 2003, the rates were differentiated to reflect PCOSS results. In the first 2 increases (Order 33/91 and Order 25/92) differentiation was modest, but then GSL >100kV customers received no increases over the remaining period to 2002, and received a 2% decrease in 2003 (Order 7/03).

Starting 2004, across-the-board increases were implemented until 2017. Order 59/18 resumed differential rate increases, with limited further application of differential increases in Orders 69/19 and 137/21.

Though there was no differentiation between the classes, from 2009 through 2012, the entire rate increase for the GSL rate classes was applied to the energy component only of the rate structure. This leads to some modest differentiation on an intraclass basis.

This does not include diesel or Area and Roadway Lighting, which often had differential increases applied.

b)

To provide an accurate reply, it would be necessary to review each of the respective PCOSS report analyses, which are not readily available at the current time. However, Mr. Bowman expects that none of the PCOSS studies prior to 2016 would have used the new approach, so the reported RCC ratios are tightened (in percentage terms) compared to the way they would be measured today. For example, a 110% RCC in a past period may be more akin to 113% today.

c)

The PCOSS studies reported each use slight different methodologies over the years. However, the changes shown would generally be relatively small, and not likely to lead to misleading results. Some PCOSS reports which used grossly different methods, which were basically just a proposal of Hydro but were not approved by the Board, have been omitted. For example, the chart does not include PCOSS06 based on the proposed methods, but rather the approved methods. The variations that remain would be relatively small (e.g., some of the old studies pre-date the use of the top 50 winter peaks. Some of the studies from about 2006 to 2015 would include energy on weighted basis to each time period. However, these variations would be relatively small compared to the scale of persistent results seen in the above figure.

PUB/MIPUG I-14

Part and Chapter:	**InterGroup Evidence p. 59 Rate Differentiation Based on 2024/25 NER**	**Page No.:**	
Topic:			
Sub Topic:			

PREAMBLE TO IR:

Preamble:

In his evidence on page 59, Mr. Bowman states:

> Since the preparation of Tab 8, Hydro has provided the results of PCOSS analysis for 2023/24 using a normalized water and export market regime consistent with the 2024/25 financial forecast. That analysis clarified that the impact of high water in PCOSS24 was not the reason for the high industrial class RCCs. Indeed, the RCCs for the two largest industrial classes (GSL 30-100 kV and GSL >100 kV) remain at 110.2% and 110.3% respectively under the normalized water scenario. Elimination of the 5+ percentage points over 5 years would still require a differentiation compared to the average 2% rate increase of over 1% (i.e., rate increases for industrials below 1%), far below the level proposed by Hydro in this proceeding.

QUESTION:

Please calculate the rate differentiation (rate increases) needed in the test years in order to move all customer classes into the zone of reasonableness over five years using RCC ratios based on 2024/25 net export revenues as the starting point. Assume the parameters the Board has previously given to MH for rate differentiation: any revenue deficiency from below-average rate increases to classes above the zone of reasonableness is to be recovered from classes within and below the zone of reasonableness.

RESPONSE:

Because of compounding effects, Mr. Bowman is only able to provide an estimate rather than a precise value, which should be provided by Manitoba Hydro. In approximate terms, the rate differentials needed to address the classes above the ZOR within 5 years are very close to 1% below the average increase (i.e., 1% increase to the classes above, compared to 2% average increase to the system). This would affect GSS-ND, GSL 30-100 kV, GSL >100 kV, and Area and Roadway Lighting. The total domestic revenue from this group is approximately $500 million. A 1% lower rate increase than average would reduce revenues by $5 million, which would need to be made up by the other classes. The remaining class revenues are approximately $1.32 billion so the extra increase to the other classes would be on the order of 0.4%.

PUB/MIPUG I-15

Part and Chapter:	**InterGroup Evidence pp. 61, 62** **Rate Increase Applied to the Demand Rate**	**Page No.:**	
Topic:			
Sub Topic:			

PREAMBLE TO IR:

Preamble:

In his evidence on page 61, Mr. Bowman states:

> In regard to the second matter noted above – the application of the entire rate increase to the demand charge, this is a proposal that will improve price signals, but at the expense of adverse customer impacts in some cases. While it is in principle consistent with the cost profile of the system, acceptance by the PUB will need to also address customer impacts, which is beyond the scope of this submission.

QUESTION:

Considering the most unfavourably affected industrial customer will see a 2.3% increase as a result of implementing the rate increase solely to the demand charge (which is within the range of customer class impacts proposed in this GRA), please explain why these customer impacts will require the PUB to address them, and what mitigation measures are needed in order to address these impacts.

RESPONSE:

The need for careful consideration arises due to disparate impacts on customers within a class, where these impacts are not well tied to the class situation as a whole. For example, in this application, the GSL >100 kV class is measured to be paying a Revenue:Cost Ratio of 113%. This means they are paying 13% above the costs to serve the class. A reasonable expectation of members of this class is a below average rate impact. Instead, the proposal is to increase the class rates by 1.5% on average, but the question cites that for some customers this could be a 2.3% increase or more (which is above the average for the system).

This situation would not arise to the same degree if Hydro had targeted the Board directed pathway to reach ZOR by 2027/28. Then the overall class increase for GSL >100kV would be lower, and the pressures on members of the class that use a proportionally higher percentage of the demand component would also be less. As one example, Hydro could have achieved this by imposing a 2% increase in the demand charge for GSL >100 kV while leaving the energy charge unchanged. This would ensure no customer in the class sees a higher than average rate increase in the test year.