MIPUG/GSS-GSM I-1

Part and Chapter:	4.1.1 – GSS and GSM Rate Comparisons	**Page #:**	PDF p. 24 - 25
Topic:	Report on GSL 750 V – 30 kV Diversity and Potential Cross-Subsidies		
Subtopic:	Request for Similar Report for GSS and GSM		

Preamble (if any):

GSS-GSM Evidence:

"*Manitoba Hydro filed an analysis of the GSL 0-30kV class in this proceeding (Appendix 7.3) which considered the current class rate structure, potential segmentation and potential cross-subsidies within the class.*[94] *Given the diversity of customer mix within the GSS and GSM classes and the complexity of the current rate structure, it is worthwhile for Manitoba Hydro to undertake a similar type of review for these rate classes. Specifically an analysis that looks at potential cross-subsidies, overlap between the GSS and GSM rate classes, potential deharmonization between the GSS-ND and GSS-D classes (following suit from the deharmonization of GSS-D and GSM in the last GRA) and potential simplification to the current rate structure. The PUB should direct Manitoba Hydro to consult with these customer classes and file in the next GRA or potentially a Rate Design specific proceeding.*" [Section 4.1.1, PDF p. 24-25]

Appendix 7.3

"*Theoretically a rate could be developed to reflect the specific cost of providing electric service to each customer, but in practice defining customer classes and developing rate structures needs to also consider the administrative feasibility of billing customers. It is not practical to create a rate for each individual customer that would entirely eliminate all cross subsidies, nor is it practical to create numerous small subclasses if the subclasses would only include a handful of customers with modest overall energy consumption. Recognizing these practical limitations, Manitoba Hydro examined the RCC improvement that could be achieved by further dividing GSL 750 V – 30 kV into two subclasses*." [PDF p. 5]

Appendix 7.3

"*Unit costs are calculated by dividing the net costs for the GSL 750 V – 30kV subclass in PCOSS24 by the allocator used for each type of cost in the study. The unit costs are net costs since the Generation and Transmission costs have been reduced by net export revenues. The calculation of unit costs is provided in Figure 5*." [PDF p. 6]

Figure 5: Calculation of GSL 750 V – 30 kV Net Unit Costs from PCOSS24

	Energy ($/kWh)	CP Demand ($/kW)	NCP Demand ($/kW)	Customer[2] (% of Revenue)	Customer ($/Cust)
Net Cost for Subclass	57,042,767	42,539,113	24,273,907	2,967,326	810,325
Allocator Quantity	1,876,380,639	266,138	296,171	125,005,052	378
Net Unit Cost	0.03	160	82	2.4%	2,144

Appendix 7.3

"*Despite using the same assets, the cost to serve each customer within a class may vary due to differences in the consumption patterns between customers. Therefore, defining classes so that the customers within a class are highly homogenous is theoretically preferable since it avoids potential cross subsidies between customers within the class.*" [PDF p. 2]

Question:

a) In submitting the above recommendation, was consideration given to the methodology used for "Evaluation of Potential for Reduction in Cross Subsidization" in Appendix 7.3 [PDF p. 5]

If the response to a) is "Yes":

b) Please explain how the approach used for dividing GSL 750 V – 30 kV into two subclasses may be applicable to a similar analysis for GSS and GSM rate classes.

c) Please explain how the approach for determining average unit costs for energy and demand, based on total class costs and allocators, applied equally to customers in the two subclasses, may impact the outcome of an analysis to evaluate the potential for reduction in cross subsidization.

d) Does Ms. Davies agree with Manitoba Hydro's position that "the cost to serve each customer within a class may vary due to differences in consumption patterns between customers"?

e) Does Ms. Davies agree that applying the same average unit costs equally to the two subclasses, used for evaluation of potential for reduction in cross subsidies, may not be appropriate, given Manitoba Hydro's position as noted in d) above?

Rationale for Question:

Determine the appropriateness of the methodology used in Appendix 7.3 for evaluation of potential to reduce cross subsidization.

Response:

a) Yes this was considered, especially in the balance between cross-subsidy and complexity - as the GSS rate class specifically as it is designed is very complex compared to the amount of energy the customers in this class tend to use yet the result is a pattern of overpayment of revenue compared to costs (cross-subsidization) for GSS-ND customers.

b) It could generally be a useful exercise, especially if harmonious rate design can not be achieved that ensures GSS-ND and GSS-D rate classes are each charged rates that align with both the variable and fixed portion of costs; therefore segmenting the two into separately designed rate structures (similar to what was done between GSS-D and GSM).

The key rate design issues to review for GSS and GSM are - 1) if the splitting between subclasses is occurring at an appropriate level (especially for customers on the cusp that move back and forth between GSS and GSM but also for customers between GSS-ND and GSS-D); and 2) if the rate design is collecting costs at appropriate and cost reflective levels (i.e. fixed costs collected appropriately between customer charge, demand charge and some portion of first block energy rate; and variable charges collected by some portion of first block rate and remaining blocks).

In Appendix 7.3, Manitoba Hydro looked at subdividing the GSL 0-30kV class by end use, energy consumption, peak demand and load factor.

Largely for a review of GSS and GSM customer classes, splitting by peak demand is already occurring naturally within the rate design itself (i.e. a demand charge that activates above a certain peak usage threshold for both classes). This tends to naturally split by energy as well (since higher sustained peak demand usage usually includes higher overall energy usage). Splitting rate design by demand is a common approach to segmentation.

To split by end use for the GSS and GSM classes would be difficult given the diversity of user and also the way customer sectors are labelled within the classes, though this doesn't necessarily rule it out as potentially useful. For example, there are 5,300 industrial customers in the GSS-ND class – which seems like a strange distinction from commercial at face value given the average monthly usage for these customers is 2,835 – less than a high-end Residential user.[1] Comparatively there are far fewer Industrial customers in the GSS-D and GSM classes. As well, it is not a common approach for mid-level users to be split by end use – the main example of this being used in Canada is for a 'Farm/Agriculture' specific rate or when electric heat Residential customers are grouped into GSS or GSM classes. This usually is done for Farms/Irrigation to provide low cost energy in summer months to support these types of activities when its mutually beneficial for both the utility and the customer; or in cases where Farming is a large contributor to the

[1] As per Ms. Davies evidence, page 21

economy and/or has a distinct load profile not properly served by other rate class structures. For Residential heating customers, often these are the types of customers driving system peak related costs, and therefore there's sometimes talk of separating their rate structure to ensure there are proper cost signals (or instead transparently providing subsidization to support electrification policies).

To split by load factor is unusual for defining a new rate class, usually cross-subsidy within a class of this nature can be managed through rate design and/or in optional rate offerings. However, there are examples for larger customer classes, Hydro-Quebec offers a 'low load factor' or limited-use rate option within its medium and large power classes – largely for customers that have changed usage patterns over the course of the year (golf courses, skill hills, etc.).[2]

Even in the scenarios that don't have much precedent for segmenting rate classes, useful information can be gleaned for rate design purposes.

c) The approach for determining average unit costs for energy and demand is based on the underlying cost of service methods so if costs differ within a class for different customer segments this often won't be captured. For example, within a rate class one group may be contributing much more to peak demand usage than another (for example, this is often seen in GSS and GSM classes where Residential customers with electric heat are grouped in – which generally more strongly contribute to coincident peak load when peak demand occurs due to cold weather).

   However when comparing average unit costs for segmentation purposes generally these distinctions are not pulled out and the same demand unit cost is used for the segment contributing more to peak as a segment which does not have the same type of usage (for example a customer with a much higher and more consistent load factor, or a farm customer that primarily peaks in summer over winter).

   It can lead to a misrepresentation of actual segment costs, which if not addressed quantitatively should at least be acknowledged and considered qualitatively.

d) Yes, Ms. Davies agrees with Manitoba Hydro's position that "the cost to serve each customer within a class may vary due to differences in consumption patterns between customers, as described in part (c) above.

e) Yes, as described above in part (c).

[2] As explained on Hydro-Quebec website, available online: https://www.hydroquebec.com/business/customer-space/rates/rate-g9-general-rate-limited-use-power.html?utm_source=chatgpt.com

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Part and Chapter:	6.2 – COSS Distribution Classification	**Page #:**	PDF p. 30 - 35
Topic:	Classification Methods		
Subtopic:	Allocations of Poles & Wires Costs		

Preamble (if any):

GSS-GSM Evidence

"*The number of customers and density of an area will also contribute to distribution plant operating costs, including the expediency of maintenance and replacement costs. Upgrades to the system are just as likely to be triggered by increasing number of customers as additions to load. The current classification method captures almost none of this, as the classification of distribution plant assets results in 97% of the distribution plant system being classified to demand, as shown in the table below. The end result is the larger customers that use distribution assets will be allocated much more than their fair share*." [PDF p. 31]

Classifying distribution Pole & Wire costs, and potentially Transformer costs as well, entirely to demand serves to overcharge larger customers – primarily the GSS-D and GSM classes as the GSL classes are largely exempt from these expenses. [PDF p. 32]

See also: Appendix 7.1, Tables F1 and F2 [PDF p. 34 – 36]

Question:

a) Does Ms. Davies agree that Pole and Wire costs of $245.3 M [Table F1, Appendix 7.1] account for 57% of the $428.4 M in total Distribution Plant costs?

b) Does Ms. Davies agree that GSL 750 V – 30 KV allocations of Poles & Wire costs identified in Allocation Table F2, Appendix 7.1 indicate that GSL 0 – 30 customers are subject to an allocation share of the $171.7 M in primary distribution costs for Poles & Wires.

c) Based on b), does Ms. Davies agree that GSL classes, particularly the GSL 750 V – 30 kV subclass, are not largely exempt from Pole & Wire costs?

Rationale for Question:

Confirmation of GSL 750 V – 30 kV allocations of distribution costs.

Response:

a) Agreed (referred to as 'Lines' in Table F1 from Appendix 7.1)

b) Yes, Manitoba Hydro splits its Poles & Wires costs - 70% as ‘primary’ and 30% as ‘secondary’.[3] As the GSL 750 V – 30 kV class is only allocated a portion of the primary Poles & Wires costs, this would amount to a share of the $171.71 million (70% of total Poles & Wires of $245.3 million).

c) Agreed, the GSL 750 – 30 kV subclass currently pays approximately 5.44% of total Pole & Wires costs,[4] so approximately $13.3 million in allocated costs for Poles & Wires.

[3] As described by Manitoba Hydro in response to PUB/MH-I-49a-b.in the 2015 COSS Review
[4] As per Allocator Table D36 in Appendix 7.2, page 15

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Part and Chapter:	6.2 – COSS Distribution Classification	**Page #:**	PDF p. 30 - 35
Topic:	Classification Methods		
Subtopic:	PLCC Adjustments within Minimum System Study		

Preamble (if any):

GSS-GSM Evidence

"*Other utilities, including SaskPower and FortisBC (Electric), acknowledge that the customer related portion of costs will still be able to serve a certain level of peak load. This seems to have been Mr. Chernick's argument for entirely eliminating any classification to customer in the 2015 COSS review. However, rather than eliminate the classification entirely, these utilities incorporate a PLCC adjustment within a Minimum System study to the customer-related portion to avoid overclassifying to customer.*" [PDF p.35]

"*Undertaking the Minimum System study in this matter helped as a crosscheck to the existing judgment-based approach. And while there was disagreement about the method to employ and the assets used to estimate a 'minimum system', the justification to split distribution main costs between customer and demand was not questioned. Comparatively the Manitoba Hydro 2015 COSS review did not undertake this level of analysis on an issue that has material impacts for the GSS and GSM rate classes.*" [PDF p. 36]

Question:

a) Please explain how PLCC adjustments to the customer-related portion within a minimum system study is used to avoid overclassifying to customer.

b) Can Ms. Davis confirm whether FortisBC is currently using PLCC adjustments for distribution classification?

c) Can Ms. Davis confirm whether SaskPower is currently using PLCC adjustments for distribution classifications?

d) Does Ms. Davis agree that the adoption of a minimum system study may have a material impact for the GSL 750 V – 30 kV subclass?

Rationale for Question:

Use of customer allocators for allocation of distribution costs.

Response:

a) A minimum system study will estimate the smallest average standard distribution-plant cost (poles, wires, transformers, etc.) for a customer to be connected to the electricity system. The minimum cost is treated as customer-related, expressed as a percentage of total asset costs and allocated to customer classes in the COSS on the basis of total customer numbers.

The theory behind a Peak-Load Carrying Capacity (PLCC) adjustment is that even this minimum system provides some level of electric peak load carrying capacity to each customer (i.e. can serve a portion of demand-related needs). To avoid allocating this demand-related portion of the minimum system a PLCC adjustment is applied so that the resulting method more closely matches the theoretical demand and customer components of the distribution-plant system.

The PLCC is not necessarily applied to the customer-related distribution plant costs resulting from a minimum systems system; it is generally a correction applied to the demand allocator used to allocate demand-related distribution plant costs. For example, detailed in part (b) below, FortisBC applies the PLCC adjustment as a credit to the NCP demand allocator used (reducing customer class NCP demand allocation by corresponding peak load carrying capacity per customer i.e. average minimum system capacity per customer) such that classes with a higher number of customers will receive a larger total credit to their NCP and share of demand-allocated costs decreases accordingly – offsetting potential double counting of demand .

Generally speaking, a PLCC estimate will be specific to the minimum system study inputs used by a utility (same engineering assumptions used to generate the minimum systems study), is largely theoretical, and will be very small.

b) Yes, as per FortisBC's 2025 Updated Electric Cost of Service Study, prepared by EEC consulting, the minimum system analysis is used to determine the lowest level of plant investment required to serve a utility's customers compared to the actual facilities in place, to meet varying customer demands. FortisBC staff provided the data necessary to complete the minimum system study using 2023 data for the Poles, Towers & Fixtures, Conductors & Devices, and Line Transformers accounts. Along with the minimum system results, an offset to account for the peak load carrying capability (PLCC) of a minimum system was incorporated into the NCP allocator used to allocate distribution-plant demand-related costs.

For the 2023 study, FortisBC engineers determined that the average PLCC for the FortisBC system was 0.97 kW per customer, which is credited against the classification's non-coincident peak demands (number of customers/connections x PLCC for minimum systems) used for determining demand allocators. The adjusted NCP allocator can then be used to allocate distribution-plant demand-related costs, eliminating the double-counting. This analysis appears to be updated every five years approximately (last updated in 2017).[5]

c) Yes, while SaskPower's Cost Allocation Study does not appear to be public, it holds a public review of the COS methodology approximately every five years, most recently undertaken in 2023.[6] The methodology review indicates the classification for distribution lines and transformers between customer and demand related is determined using the minimum systems method and includes a PLCC adjustment.[7]

d) It could potentially have a material impact for the GSL 750 V – 30 kV subclass depending on the result.

As an example, as shown in response to GSS-GSM/MH II 9a-c, if the study resulted in a classification split change for Poles & Wires in line with previous COSS methodology (i.e. 60% to demand and 40% to customer), the result based on PCOSS26 for the GSL 750 V – 30 kV subclass would be an increase in the RCC ratio from 100.9% to 105.0% or a net reduction in costs by $5.3 million.

[5] Detailed in 2025 Electric Cost of Service Study, prepared by EES Consulting for FortisBC's 2025 COSA and Rate Rebalancing Application, pdf pages 142 – 145, available online: https://docs.bcuc.com/documents/proceedings/2025/doc_81642_b-1-1-fbc-2025-cosa-application-updated.pdf

[6] As detailed on SaskPower's website, available online: https://www.saskpower.com/accounts/power-rates/2023-cost-of-service-methodology-review

[7] 2023 SaskPower Cost Allocation and Rate Design Methodologies Review by Elenchus Research Associates, pages 40 – 42, available online: https://www.saskpower.com/-/media/saskpower/accounts-and-services/rates/cost-of-service-2023/report-rates-elenchus-costallocation-ratedesign-2023.pdf

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Part and Chapter:	6.3 – Approach for Classification Weighting	**Page #:**	PDF p. 35 - 37
Topic:	Classification Methods		
Subtopic:	Primary/Secondary and Demand/Customer Splits		

Preamble (if any):

GSS-GSM Evidence

"*Alternatively, there are two other options that could be implemented in this proceeding on the basis of professional judgment that fall within Canadian utility benchmarking – and in line with the PUB's recent Centra Order:*

1) *Revert back to the 60% demand/40% customer split used prior to 2015 (results as shown in GSS-GSM/MH II-9b);*

2) *Use the primary/secondary split percentages to establish classification with primary classified as 100% demand and secondary as 100% customer (i.e. results in 70% demand/30% customer). This primary/secondary split is currently used in the COSS, for the Poles & Wires distribution classification to ensure the GSL 0-30kV class is not paying for the secondary distribution system (as they are not connected to it). Results of which are provided in response to MIPUG/MH II-26c.*" [PDF p. 37]

MIPUG/MH II-26 b)

"*Both the primary distribution system, which is used to serve GSL 0-30 kV customers, and the secondary distribution system, which is used to serve all distribution level customers except GSL 0-30 kV, must be designed to meet the local peak demands.*" [PDF p. 167]

Question:

a) Please explain why it may be appropriate to classify primary distribution costs as 100% demand, in contrast to the classification of secondary distribution costs as 100% customer.

Rationale for Question:

Classification of primary distribution costs as both demand and customer.

Response:

It's an approach used by some utilities to recognize that generally primary distribution lines serve a larger number of customers/area and are designed for an area's peak load, so are mostly demand-related. While secondary distribution lines are used more to deliver energy from the primary lines to smaller areas and smaller groups/individual customers, so would be more customer-related. In Canada a few utilities employ this distinction in their cost allocation methodology (BC Hydro, ATCO, Hydro-Quebec), especially those that subfunctionalize distribution-plant assets in this way but do not undertake a detailed study to develop overall classification justification between customer and demand (such as minimum systems, zero intercept).

The issue for immediate implementation is that Manitoba Hydro's current split between primary and secondary poles & wires is based on information as dated as the 60/40 classification split previously used for distribution-plant. As explained in response to PUB/MH-I-49a-b in the 2015 COSS review:

> Manitoba Hydro's accounting records do not segregate the costs of primary and secondary distribution, other than for underground distribution. The 70/30 primary to secondary cost split is based on the professional judgment and experience of the treatment of distribution investment of other utilities by its external expert consultant in 1991. No other more current estimates are available and any updates are expected to provide minimal improvements which make this the best available estimate of the relative costs.