Board Counsel Book of Documents

Volume 6

Cost of Service and Rate Design Panel

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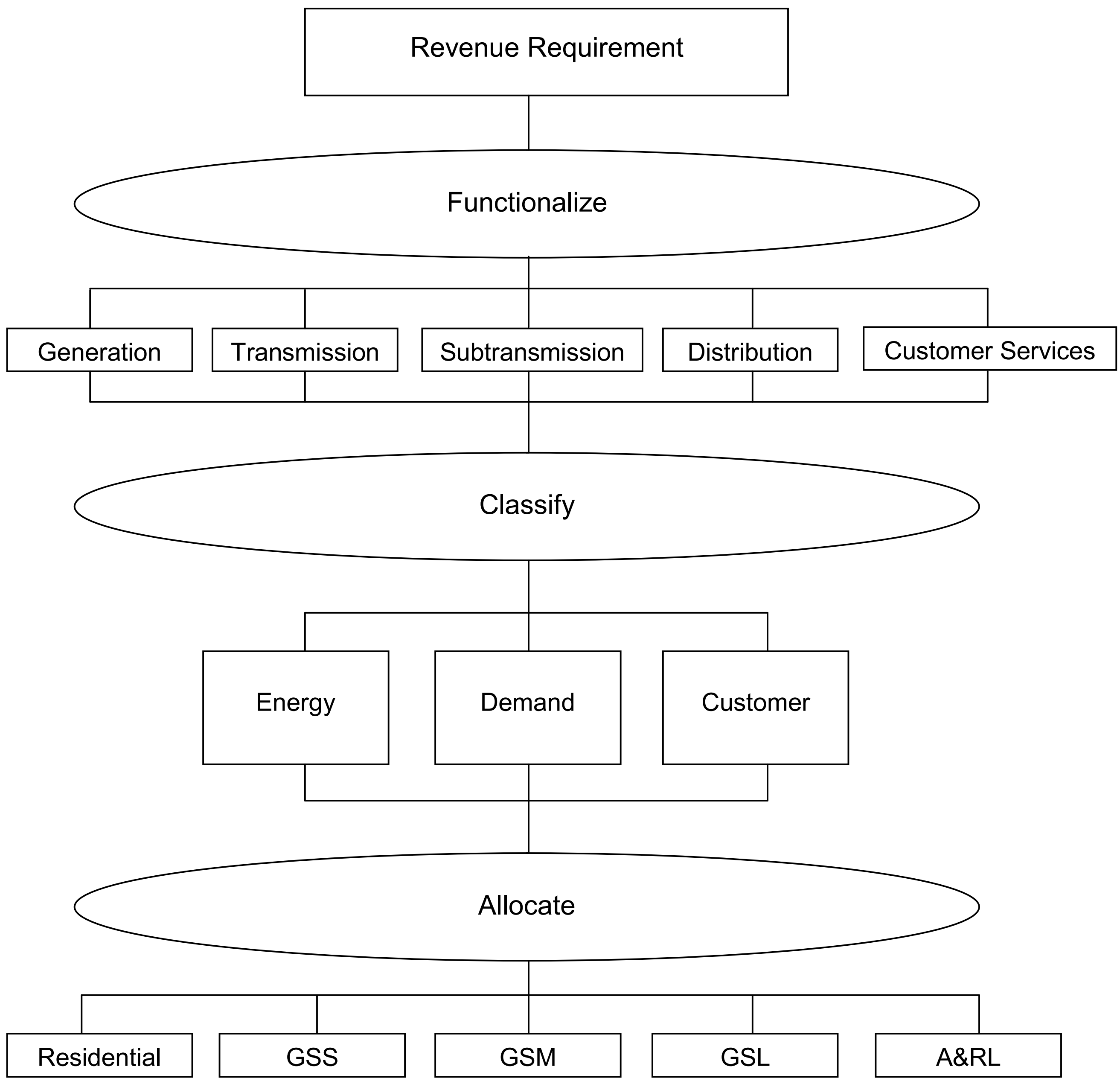
The functionalization, classification, and allocation process is illustrated in the following flow chart.



Schematic of the Functionalization, Classification, and Allocation Process

- allocate the costs, which have been functionalized and classified, among Manitoba Hydro's customer classes.

In the course of this proceeding, the Board identified the following key issues in this COSS methodology review:

- The functionalization, classification, and allocation of generation and transmission assets, including the high voltage direct current ("HVDC") system and the U.S. interconnection, but excluding wind and coal assets;

- The treatment of export costs, including the number of export classes and the allocation of fixed and variable costs to such classes;

- The treatment and allocation of net export revenue; and

- The classification and allocation of demand-side management.

Board Findings

Generation Functionalized Costs

The Board finds that Manitoba Hydro's hydraulic and thermal generating stations should be functionalized as Generation.

Transmission that is necessary to connect generating stations to the networked transmission system, including the Northern Collector System and the northern converter stations, should also be functionalized as Generation. Power flows in only one direction on these lines, from the generating station to the networked transmission system, so this transmission is only used and useful as part of the generating station.

Bipoles I, II, and III should be functionalized as Generation as they connect northern generation with southern load centres, acting as extensions of the northern generating stations. The Board also finds that the high voltage direct current ("HVDC") facilities of the Riel and Dorsey Converter Stations should be functionalized as Generation. Bipole

III will function in the same manner as Bipoles I and II and, without northern generation, the HVDC portions of Dorsey and Riel have no use or function.

Classification of Generation Functionalized Costs

The Board finds that Generation costs should be classified as both Energy and Demand. The proportions of Energy and Demand should be determined by the system load factor method. The only exceptions to this approach are wind generation, water rentals, and variable hydraulic operation and maintenance costs which are to be classified as 100% Energy.

The reason for classifying Generation costs as both Demand and Energy is that Manitoba Hydro plans for and invests in assets to satisfy both peak demand and the energy requirements of Manitobans that must be met during drought conditions, when hydraulic generation is limited.

To determine the split between Demand and Energy classified costs, the Board directs the use of the system load factor as it is straightforward, is generally accepted in the industry, and has a clear basis in cost causation.

Allocation of the Generation Functionalized and Classified Costs

The Board finds that the Demand component of Generation costs should be allocated by the top 50 Winter Coincident Peak hours. Allocating Demand costs by Winter Coincident Peak reflects the shape of the domestic customer class loads during the high demand winter months in Manitoba.

The Energy component of Generation costs, as well as Generation costs that are classified as 100% Energy (i.e. wind purchases, water rentals, and variable hydraulic operating and maintenance costs) should be allocated to customer classes on the basis of customer class energy consumption (i.e. unweighted energy).

Transmission Functionalized Costs

The Board finds that the alternating current ("AC") transmission system operating at voltages greater than 100kV, the interprovincial interconnections, and the U.S. interconnections should be functionalized as Transmission. The costs of AC transmission are incurred to meet higher peak demand, maintain or enhance transmission network reliability, or geographically expand the AC network to serve additional load. The U.S. and interprovincial interconnections import and export energy and are sized for load rather than for generation output.

Classification and Allocation of Functionalized Transmission Costs

The Board finds that the costs of domestic AC and interprovincial transmission lines should be classified as 100% Demand and allocated on the basis of Winter Coincident Peak.

The U.S. interconnections should be classified on the basis of system load factor. The Demand portion should be allocated on the basis of Winter Coincident Peak and the Energy portion on the basis of unweighted energy.

Export Class and Export Revenues

The Board finds that an Export class should not be used in the COSS. The Board concludes that the Export class is not a vehicle for measuring the profitability of Manitoba Hydro's export business. A COSS does not measure any risks associated with the export venture, or the prudence of any resource development plans. The Export class is not like the domestic classes because export prices are determined either by markets or negotiated directly with export customers. Domestic customers, not export customers, are responsible for the costs of all of Manitoba Hydro's assets and operations.

The crediting of export revenue to the domestic classes should be based on each class's share of only Generation and Transmission costs. This approach is consistent with the principle of cost causation, as Manitoba Hydro's Generation and Transmission assets are the only functions utilized to effect export sales and thus the export revenues. Crediting export revenue on the basis of each class's share of Generation and Transmission costs is effectively equivalent to not having an Export class, making the Export class redundant.

Specific costs should be deducted from gross export revenues prior to the crediting of export revenues to the domestic classes. The costs to be deducted are water rentals, variable hydraulic operating and maintenance costs associated with exports, and the Affordable Energy Fund.

Demand-Side Management ("DSM")

The Board finds that DSM costs should be functionalized as 100% Generation. These costs should be classified the same way as other Generation assets based on system load factor, and allocated on Winter Coincident Peak for the Demand portion, and unweighted energy for the Energy portion.

DSM reduces overall domestic energy consumption, peak demand, or both. DSM is a system resource that avoids Generation costs.

Other Issues

In this Order the Board also provides direction to Manitoba Hydro as to the methodology to be employed on other issues when preparing its next COSS to be filed in conjunction with its next GRA. Specifically, these other issues are Subtransmission, Distribution, Customer Services, and common costs, as well as the treatment of Late Payment Revenue and the Area and Roadway lighting customer class.

Compliance Filing

The Board directs Manitoba Hydro to provide a Compliance Filing which demonstrates the directives of the Board have been included in Manitoba Hydro's COSS model.

("GSS/GSM") suggests that a foundational set of principles is needed to inform cost allocation, which in turn informs the next step of the ratemaking process which is rate design.

Board Findings

The Board finds that, in the process to determine the appropriate COSS methodology, the principle of cost causation is paramount. Further, the Board finds that ratemaking principles and goals should not be considered at the COSS stage.

The Board finds that Manitoba Hydro's ratemaking principles and goals of rate stability and gradualism, fairness and equity, efficiency, simplicity, and competitiveness of rates should be considered in a General Rate Application ("GRA") and not in the cost of service methodology. While ratemaking principles are important in the overall process of setting rates, these concepts are issues for rate design and should therefore not be considered at the COSS stage. Likewise, consideration of RCC ratios is a rate design matter that should be addressed in the rate-setting phase of a GRA.

Cost causation as defined by the Board takes into consideration both how an asset is planned and how that asset is used. This takes into account how an asset fits into Manitoba Hydro's current system planning, as well as the current use. This methodology is to apply to assets currently in service, as well as future assets, such as Keeyask and Bipole III.

The Board also finds that cost causation requires consideration of all the uses and benefits of an asset, to recognize that both primary and secondary benefits influence the planning and justification of assets. These considerations should be assessed over a range of years (as opposed to a single forecasted year) and over a range of conditions in order to capture all of the uses and benefits of an asset in determining cost causation.

The Board finds that, as acknowledged by Manitoba Hydro, it is not bound by prior Board decisions. As such, the Board has approached this review of Manitoba Hydro's

As previously noted, while a COSS appears to be arithmetically exact, it involves a number of decisions that require the application of judgment. Because of this, and to address goals of gradualism in the ratemaking process, many utilities do not set rates such that the RCC ratios are exactly unity. Instead, many utilities and their regulators, including Manitoba Hydro and the Board, recognize a zone of reasonableness within which the utility is to target the RCC ratios of its customer classes. Manitoba Hydro's zone of reasonableness is currently 0.95 to 1.05, meaning that Manitoba Hydro considers it reasonable when a customer class's rates are set to recover between 95% and 105% of the costs allocated to that class in the COSS. RCCs and the zone of reasonableness are rate design issues that are addressed in the context of a GRA.

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21. Manitoba Hydro continue the annual deferral of $20 million in ineligible overhead. The regulatory account balance is to be amortized over 34 years.

22. Manitoba Hydro's request to begin recognizing the Bipole III Deferral Account in domestic revenues following the in-service date of Bipole III, amortized over a five-year period **BE AND IS HEREBY APPROVED**.

23. Manitoba Hydro discontinue the accounting practice of recognizing a Demand Side Management Deferral Account.

24. Manitoba Hydro exclude non-tariffable transmission costs from the allocation of export revenues in its future Prospective Cost of Service Studies.

25. Manitoba Hydro allocate the activities of building moves & safety watches, contact centre-outages, line locates, and marketing research & development costs to all customer classes other than General Service Large 30-100kV and General Service Large >100kV in future Prospective Cost of Service Studies.

26. Manitoba Hydro complete the study of the Service Drops Allocator and the Common Costs study in time for its next Prospective Cost of Service Study.

27. Manitoba Hydro calculate Revenue to Cost Coverage ratios using the alternative methodology of treating export revenues as a reduction to class costs in future Prospective Cost of Service Studies filed with the Board.

28. Manitoba Hydro provide in its next GRA filing the rationale for the declining block rate design for the General Service customer classes and an evaluation of the block thresholds and charges.

PART 11

OTHER AMENDMENTS

DIVISION 1

RATES FOR POWER AND NATURAL GAS

Increase in Manitoba Hydro rates
233(1) Effective December 1, 2020, for all customer classes, Manitoba Hydro must increase the rates it charges for power supplied by the corporation by 2.9%.

Exclusions
233(2) The increase required under subsection (1) does not apply to

(a) the rates charged to diesel customer classes, other than

(i) a rate charged to a diesel customer class that is equal to the equivalent grid rate, or

(ii) a component of a rate charged to a diesel customer class that is equal to the corresponding component of the equivalent grid rate; or

(b) the rates under

(i) the surplus energy program, or

(ii) the curtailable rate program.

Increases not subject to approval
233(3) The increase required under subsection (1) is not subject to

(a) section 39, except subsections (2.1) and (2.2), of *The Manitoba Hydro Act*; or

PARTIE 11

AUTRES MODIFICATIONS

SECTION 1

TARIFS AFFÉRENTS À L'ÉNERGIE ET AU GAZ NATUREL

Augmentation des tarifs d'Hydro-Manitoba
233(1) À compter du 1[er] décembre 2020, pour toutes les catégories de clients, Hydro-Manitoba est tenue d'augmenter de 2,9 % les tarifs qu'elle fixe pour l'énergie qu'elle fournit.

Exceptions
233(2) L'augmentation prévue au paragraphe (1) ne s'applique pas :

a) aux tarifs qu'elle fixe pour les catégories de clients d'un service d'électricité produite par le diésel, à l'exception de ce qui suit :

(i) un tel tarif, s'il est égal au tarif équivalent en réseau,

(ii) une composante d'un tel tarif, si elle est égale à la composante correspondante du tarif équivalent en réseau;

b) aux tarifs qui se rattachent à l'un ou l'autre des programmes suivants :

(i) Programme d'énergie excédentaire,

(ii) Programme de tarifs pour service interruptible.

Aucune approbation requise
233(3) L'augmentation prévue au paragraphe (1) n'est pas assujettie :

a) à l'article 39, à l'exception des paragraphes (2.1) et (2.2), de la *Loi sur l'Hydro-Manitoba*;

(b) Part 4 (Public Utilities Board Review of Rates) of *The Crown Corporations Governance and Accountability Act*.

Treatment of increased revenue
234 The revenue generated from the rate increases provided for under this Division is to be recognized immediately in Manitoba Hydro's and Centra's general revenues, respectively, and is not to be deferred to a regulatory deferral account for future recognition.

Rate schedules to be made public
235 Manitoba Hydro and Centra must prepare rate schedules that include the increases required under section 233 and publish the schedules on a publicly accessible website before December 1, 2020.

b) à la partie 4 (Examen des tarifs par la Régie des services publics) de la *Loi sur la gouvernance et l'obligation redditionnelle des corporations de la Couronne*.

Traitement des recettes générées par les augmentations
234 Les recettes générées par les augmentations tarifaires prévues à la présente section sont constatées immédiatement dans les recettes générales d'Hydro-Manitoba et de Centra, respectivement, et ne sont pas reportées dans un compte de report réglementaire à des fins de constatation future.

Publication de grilles tarifaires
235 Hydro-Manitoba et Centra sont tenues de préparer des grilles tarifaires comprenant les augmentations prévues à l'article 233 et de les publier sur un site Web accessible au public avant le 1er décembre 2020.

DIVISION 2

THE HELEN BETTY OSBORNE MEMORIAL FOUNDATION ACT

C.C.S.M. c. H38.1 amended
236 ***The Helen Betty Osborne Memorial Foundation Act*** *is amended by this Division.*

237 *The title is amended by striking out* "FOUNDATION" *and substituting* "FUND".

238 *The preamble is amended*

(a) in the first, second and sixth paragraphs of the English version, by striking out "aboriginal" *and substituting* "Indigenous"*; and*

(b) in the sixth paragraph, by striking out "creating a foundation" *and substituting* "maintaining a fund".

SECTION 2

LOI SUR LA FONDATION COMMÉMORATIVE HELEN BETTY OSBORNE

Modification du c. H38.1 de la ***C.P.L.M.***
236 *La présente section modifie la* ***Loi sur la Fondation commémorative Helen Betty Osborne****.*

237 *Le titre est modifié par substitution, à* « LA FONDATION COMMÉMORATIVE », *de* « LE FONDS COMMÉMORATIF ».

238 *Le préambule est modifié :*

a) dans les premier, deuxième et sixième paragraphes de la version anglaise, par substitution, à « aboriginal », *de* « Indigenous »*;*

b) dans le sixième paragraphe qui suit « Attendu : », *par substitution, à* « la création d'une fondation », *de* « le maintien d'un fonds ».

lighting plant that do not benefit any other customers, 38% of the LED conversion costs have been directly assigned to the A&RL class[1]. The RCC impact of these methodology changes is shown in Figure 8.2.

Figure 8.2 RCC Impact of Methodology Changes

Customer Class	**Directives 24-26** (NT Transmission, GSL Customer Service, Service Drop, Common Costs)	**A&RL LED DSM**	**Directive 27** (NER in RCC Calculation)	**Total**
Residential	-0.2%	0.1%	-1.9%	-2.0%
GSS Non-Demand	0.0%	0.1%	3.5%	3.6%
GSS Demand	0.1%	0.1%	0.6%	0.8%
GSM	0.0%	0.1%	0.1%	0.2%
GSL 750V-30kV	-0.1%	0.1%	-0.9%	-0.9%
GSL 30-100kV	0.6%	0.1%	5.8%	6.5%
GSL >100kV	0.7%	0.1%	6.3%	7.1%
A&RL	-0.2%	-11.8%	0.8%	-11.2%

The revised allocation of customer service costs (Directive 25) has resulted in 0.5% RCC increases for both GSL 30-100kV and GSL >100kV. The RCC impact of the methodology changes related to Directives 24, 25 and 26 are not significant for any customer classes.

Treating NER as a reduction of class cost, rather than as an addition to class revenue in the RCC calculation has the largest impact of any of the directives implemented in PCOSS24. The methodology change has the largest impact on classes that are further from unity (GSSND, GSL 30-100 kV and GSL >100 kV) as well as classes whose costs are primarily G&T related and therefore receive a larger NER offset compared to their total costs (GSL 30-100 kV and GSL >100 kV).

The direct assignment of the portion of LED conversion costs justified by maintenance savings decreases the RCC of the Area & Roadway Lighting class by 11.8%.

[1] Modification was initially incorporated in PCOSS21, which was filed as MFR20 of the 2021/22 Interim Rate Application, but the revised allocation was not reviewed during that process.

100%. It should be noted that a ZOR is a concept to address imperfections and estimation within the cost of service study. It is not a blanket justification for maintaining any specific customer class consistently at 105% or 95% in perpetuity.

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. This approach has been largely unsuccessful over many decades, as shown in the below figure summarizing Hydro's approved PCOSS studies since 1991. Note that the figure omits PCOSS21 due to the methodological issues noted earlier in this section (i.e., the study is internally inconsistent by including Keeyask costs but largely excluding Keeyask-related revenues).

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

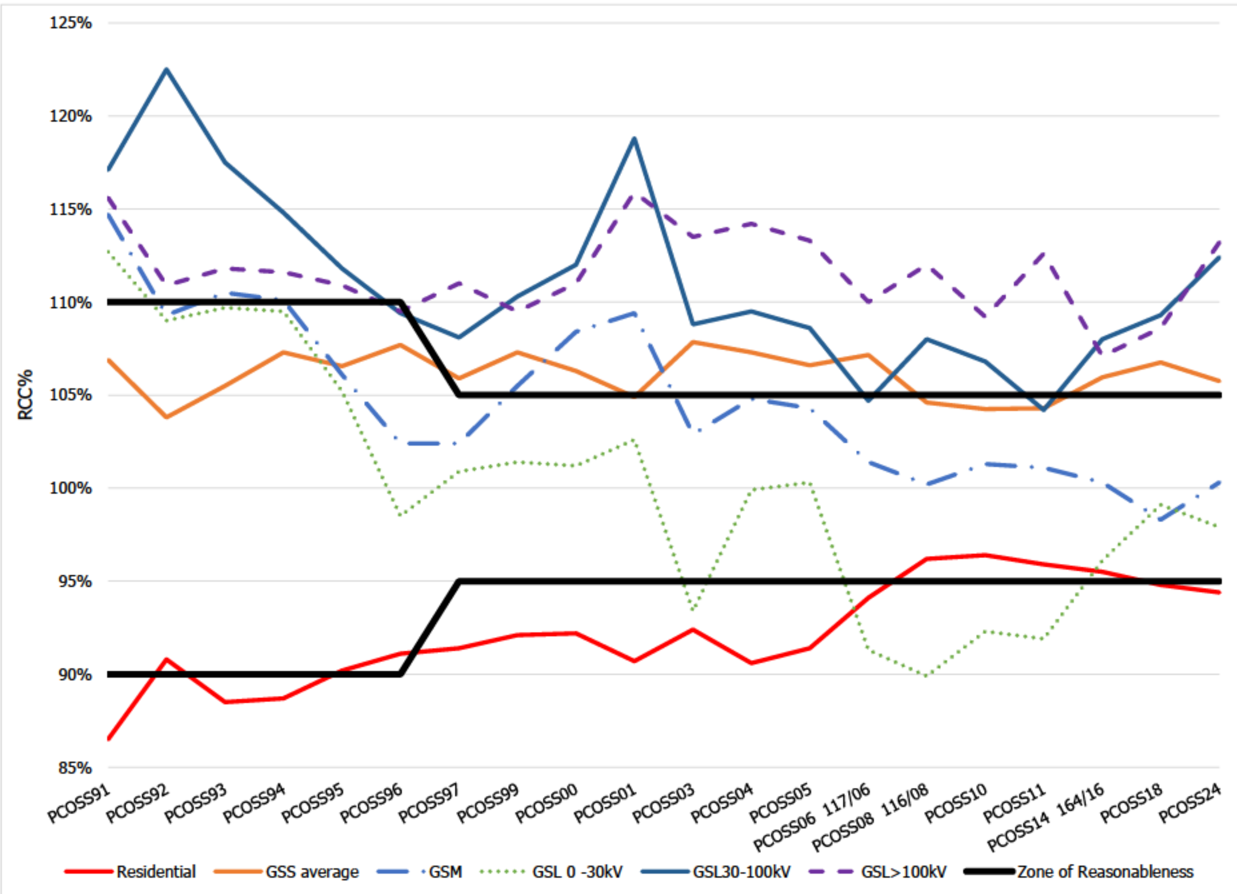

Figure 4-1 highlights that for many decades, Hydro's attempts to apply limited to no rebalancing to customer rates has resulted in some classes, notably the industrial classes (GSL 30-100 kV and GSL >100 kV) paying rates that are materially above measured costs, and other classes (notably residential) paying rates that are consistently below measured costs.

	(i) PCOSS18 Prior to NER	(ii) PCOSS18	(iii) PCOSS18 59/18	(iv) PCOSS21 Prior to NER	(v) PCOSS21	(vi) PCOSS24 Prior to NER	(vii) PCOSS24	(viii) PCOSS24 Prior to NER Sept 2023 Rates	(ix) PCOSS24 Sept 2023 Rates	(x) PCOSS24 Prior to NER April 2024 Rates	(xi) PCOSS24 April 2024 Rates
Residential	74.9%	94.8%	93.4%	74.5%	96.2%	61.5%	94.4%	62.2%	94.8%	62.9%	95.3%
GSS ND	91.9%	112.5%	115.5%	87.3%	113.8%	70.4%	109.7%	70.3%	108.7%	70.1%	107.8%
GSS D	79.4%	101.0%	101.1%	79.1%	104.0%	64.2%	101.8%	64.7%	102.0%	65.2%	102.1%
GSM	75.6%	98.3%	97.7%	74.8%	99.3%	62.2%	100.3%	62.7%	100.3%	63.2%	100.4%
GSL 0-30kV	74.5%	99.1%	98.6%	70.3%	95.6%	58.2%	97.9%	58.6%	97.9%	59.1%	97.8%
GSL 30-100kV	80.5%	109.3%	114.2%	72.5%	103.7%	60.3%	112.4%	60.4%	111.3%	60.5%	110.3%
GSL >100kV	78.2%	108.6%	113.4%	69.7%	101.2%	59.1%	113.2%	59.2%	112.1%	59.3%	110.9%
A&RL	93.8%	100.3%	100.1%	116.5%	123.3%	96.6%	108.2%	96.7%	108.2%	96.7%	108.1%

Further, the Board finds that the alternative methodology is consistent with cost causation. As stated by the Board in Order 164/16, "export revenues are not a 'dividend' that can be assigned or based on considerations other than cost causation". The domestic customer classes incur costs to facilitate Manitoba Hydro's export business. Treating export revenues as a reduction of allocated costs in the Revenue to Cost Coverage ratio aligns with the economic justification for major capital projects such as Keeyask, which is based on using the full quantum of export revenues to lower the cost of new generation and transmission.

As such, the Revenue to Cost Coverage ratios arising from PCOSS18 are:

Customer Class	**Revenue to Cost Coverage Ratio**
Residential	93.5%
General Service Small Non Demand	115.7%
General Service Small Demand	101.3%
General Service Medium	97.8%
General Service Large 0-30kV	98.7%
General Service Large 30-100kV	113.0%
General Service Large >100kV	112.3%
Area & Roadway Lighting	100.3%

In evaluating class Revenue to Cost Coverage ratios, the Board does not accept that the zone of reasonableness should be expanded to 90% to 110% and finds the zone of reasonableness should remain at 95% to 105%. While rate-making principles may justify accepting Revenue to Cost Coverage ratios that are outside of the zone, those principles do not support broadening the zone itself. A 95% to 105% range recognizes the sophistication of Manitoba Hydro's Cost of Service Study and departure from this range has not been justified.

The Board finds that the Revenue to Cost Coverage ratio output of the Cost of Service Study is to be used at this time to more closely align the revenues collected from each customer class with the costs of the electrical system that are caused by each class. As determined in Order 164/16, the Cost of Service Study is a tool that can be used in rate-making. With Manitoba Hydro's implementation of the methodology changes resulting from the Board's review of the Cost of Service Study in Order 164/16, the Utility now has a valid, regulator-approved cost of service result. While the cost of service should not necessarily be the overriding factor in designing rates, it is consistent with the rate-making principle of fairness to consider the output of the Cost of Service Study.

The Board directs Manitoba Hydro to begin to implement differentiated rates to collect the approved revenue requirement. General Service Small Non-Demand, General Service Large 30-100kV, and General Service Large >100kV are all overpaying costs to a significant degree outside of the zone of reasonableness, at 115.7%, 113.0%, and 112.3% respectively. The two General Service Large classes have been overpaying in almost every year since 1996, even using the previous ratio calculation methodology which tended to narrow the range of class ratios.

Manitoba Hydro is to adjust class revenue targets in order to begin to move the General Service Small Non-Demand, General Service Large 30-100kV, and General Service Large >100kV customer classes Revenue to Cost Coverage ratios into the zone of reasonableness. This will result in these customer classes receiving a level of rate increase that is slightly lower than the average rate increase.

For the 2018/19 Test Year rates, Manitoba Hydro is to assume a 10-year timeframe to move all classes within the zone of reasonableness, based on the alternative calculation methodology as directed in this Order. The rate increase impact of doing so is to be shared across all customer classes that are either below or within the zone of reasonableness: Residential, General Service Small Demand, General Service Medium, General Service Large 0-30kV, and Area & Roadway Lighting. As a result, the Residential customer class, which is currently the only class below the Zone of Reasonableness, will begin to move into the zone of reasonableness.

This approach to the implementation of differentiated rates is consistent with the principle of gradualism and limits the revenue recovery responsibility of the other customer classes, while maintaining overall revenue neutrality. This approach will also assist in limiting the prospect of over-correction of the issue at the time Bipole III enters service.

Manitoba Hydro is directed to include in its compliance filing for 2018/19 differentiated rates consistent with the Board's direction in this Order.

The Board will examine the Revenue to Cost Coverage ratios arising from the Prospective Cost of Service Study filed with the next GRA and will consider adjustment to the differentiation of rates as necessary, including to consider the impact of Bipole III entering service.

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by Weighted Energy. MIPUG argues that the Weighted Energy allocator used by Manitoba Hydro is too coarse to capture the true peaks on the system that drive investment costs. The result is that the weightings do not accurately reflect the load shape.

The Coalition, GSS/GSM, and GAC agree with the use of Manitoba Hydro's Weighted Energy allocator, but do not support the inclusion of the capacity adder. The Coalition agrees with Manitoba Hydro that the Weighted Energy allocator incorporates both efficiency and equity in the rate making process.

GAC argues that there does not appear to be any justification for the capacity adder as demand does not drive generation costs and domestic consumption does not affect Manitoba Hydro's ability to sell capacity in the short-term opportunity market. Similarly, GSS/GSM maintains that the proposed capacity adder is not sufficiently justified at this time and requires further review The Coalition recommends rejecting the capacity adder because it is not sufficiently justified and may lead to double counting of capacity (first through the MISO market prices and second through imposing the capacity adder).

Board Findings

The Board finds that the Demand component of Generation costs should be allocated by the top 50 Winter Coincident Peak hours. The Energy component of Generation costs should be allocated on unweighted energy.

The top 50 Winter Coincident Peak hours are the 50 hours during the winter season when Manitoba Hydro's aggregate demand reaches its peaks as a result of the combined demand of all of the domestic customer classes. The Winter Coincident Peak allocator reflects the proportional share that each customer class contributes to these peaks. Allocating by Winter Coincident Peak reflects the shape of the domestic load over the course of a year. With no Export class, there is no need to consider the summer coincident peaks when allocating Demand costs. Load research data used to estimate peak loads should consider domestic load peaks and not total generation peaks. Domestic demand in Manitoba is highest during the winter heating season, making Manitoba Hydro's domestic load winter peaking. This was not disputed in the proceeding. However, the Board recognizes that the nature of electrical systems may change over time. If Manitoba Hydro's customer mix and domestic load shape changes and becomes a system with both winter and summer peaks, then it could be appropriate to revisit the use of Winter Coincident Peak to allocate Demand-related costs.

The Board rejects the Weighted Energy allocator because it has an implicit, if limited, recognition of Demand. Weighted energy is therefore not necessary with the Board's explicit recognition of Demand classification. Furthermore, as recognized by Manitoba Hydro, with an explicit Demand classification, including weightings in the energy allocation could result in double-counting the impact of Demand on Generation costs.

Allocating on Winter Coincident Peak and unweighted energy means the COSS methodology no longer includes marginal cost considerations in the allocation of Generation costs. The Board finds that marginal cost considerations are more appropriately addressed in the rate design stage of ratemaking and not the COSS stage. As articulated in the Principles section of this Order, cost causation underpins the COSS methodology, without including other ratemaking goals. Equity and efficiency are ratemaking goals that should be addressed in a rate-setting process such as a GRA. An embedded COSS more accurately reflects cost causation than a marginal cost COSS. Accordingly, the Board approves a Manitoba Hydro COSS methodology based on embedded costs, not marginal costs.

High Voltage Direct Current ("HVDC") System Functionalization

Manitoba Hydro's Position

Manitoba Hydro functionalizes the alternating current ("AC") portions of Dorsey and Riel as Transmission. The Northern Collector System is an AC transmission system that is considered generation outlet transmission and is functionalized as Generation, as discussed previously in this Order.

day peak and not the peak used for Centra's load forecast. The latter reflects low temperatures that may fall short of the extreme temperatures used for the design day.

IGU and Koch support Centra's proposal to revisit the classification of distribution mains. Neither Intervener takes a position on the issue of the update of Centra's existing service line and meter allocation studies. IGU's expert concluded that the Mainline class is currently allocated some costs that should not be allocated to that class. Specifically, IGU's expert stated that assets functionalized as Distribution and used to supply service at less than 1,900 kPa should not be allocated to the Mainline class, except through direct assignment if certain limited assets are dedicated to serving these customers. IGU and Koch adopt the position of IGU's expert and recommend that the Board direct Centra to file, in the next general rate application, a full characterization of distribution assets allocated to the Mainline class and, if necessary, directly assign certain distribution assets to that class.

6.3 Board Findings

Allocation of the Demand Component of Costs included in Centra's Transmission and Distribution Functions

The Board approves the use of a coincident peak methodology to allocate the portion of costs related to Centra's downstream Transmission and Distribution functions classified as Demand. The allocation is to be based on an estimation of Centra's design day peak rather than the three-year average of historical demand peaks suggested by Centra.

The Board finds that a coincident peak design day allocation best reflects cost causation for the Demand component of these functions. The Board accepts Atrium's evidence that Centra must rely on design day demand in planning and constructing downstream transmission and distribution facilities. As such, a coincident peak method based on a design day approach is preferable to a coincident peak method based on an average of historical consumption peaks, even if Centra will have to rely on historical data to develop its design day metric.

In contrast, the peak and average methodology allocates Demand-related costs in part based on the annual consumption of each class. However, because Centra designs and constructs its system to meet the winter peak day, the annual use of the system does not cause Centra to incur any Demand-related costs. The Board accepts the evidence of Koch's expert that the peak and average methodology is not reflective of cost causation, as Centra's system must be sized to meet its design day peak demand.

When the Board approved Centra's use of a peak and average methodology to allocate Demand-related costs in 1996, it was concerned about system operation not being reflected in the cost of service methodology. Specifically, the Board was concerned that the Interruptible class received the use of the system without being included in the demand allocator, even though the class had the option of switching to firm service at any time, which means Centra had to design its system to accommodate the class.

As indicated by Centra in this hearing, Centra proposes to include the Interruptible class in the calculation of the coincident peak allocator. The Board considers that treatment to be appropriate as Interruptible customers are eligible to switch to firm service, and Centra must ensure that its system is designed to meet their peak demands. Centra explained that in the past 20 years it has never interrupted or curtailed service to any Interruptible customers based on downstream capacity issues.

The Board expects Centra to explain, at the next general rate application, how it arrived at a design day allocator for each customer class and how it compares to the historical peak day method for that class, including for Interruptible customers.

The Board agrees with CAC Manitoba's submission that there is a range of acceptable cost of service methods and that a cost of service study involves considerable judgment. Both the peak and average method and the coincident peak method are accepted by the U.S.-based National Association of Regulatory Utility Commissioners (NARUC), a recognized authority on public utility regulation. A change in methodology from the peak and average methodology approved in 1996 does not reflect unfairness or inequity, as submitted by CAC Manitoba. It reflects a change in methodology based on a considered review of evidence and submissions, the exercise of judgment, and the current approach of the Board as stated above.

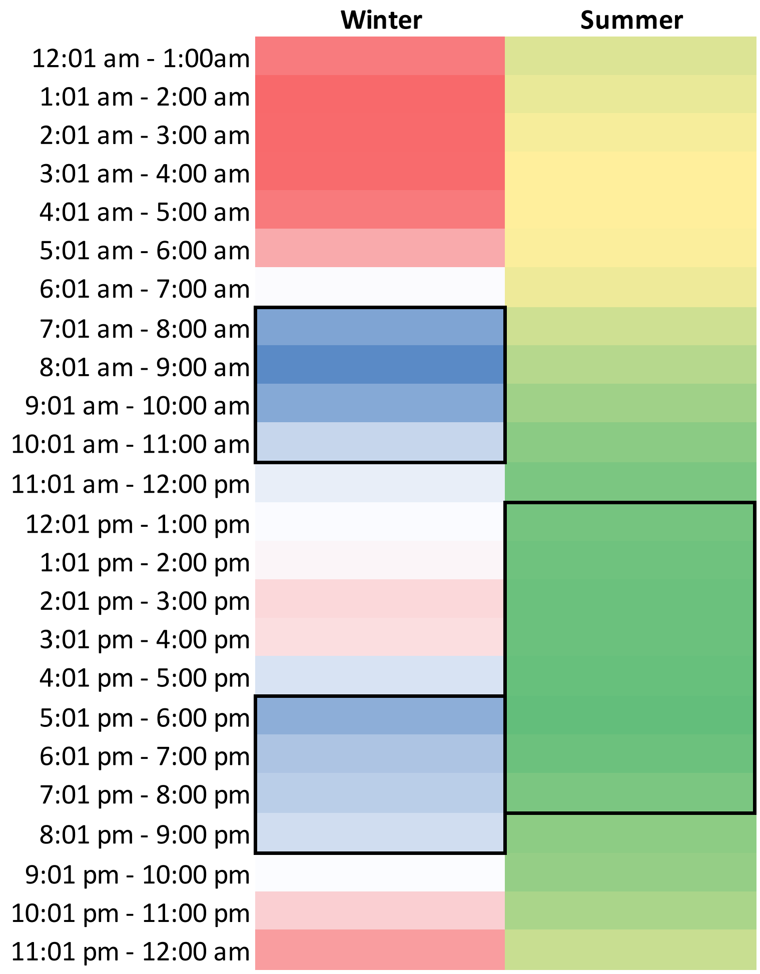
The Board notes that Order 107/96, which approved the peak and average method as part of a combined cost of service and rate design hearing, stated that expert evidence filed in that proceeding concluded that the peak day method is the most cost-causal. In the Board's view, cost of service and ratemaking should be sequential steps and not concurrent ones. It is for that reason the Board excluded matters of rate design from the scope of this hearing. Any issues of fairness or equity that the peak and average methodology may attempt to address can and should be addressed at the next general rate application.

Revised Classification of Distribution Mains

The Board finds that the minimum system approach is the best manner of classifying the distribution mains included in Centra's Distribution function. The Board accordingly directs Centra to complete a minimum system study. The cost data included in the study are to be indexed to inflation.

If Centra's minimum system study is ready in time for the utility's next general rate application, Centra's cost of service study for that application is to be based on the classification percentages suggested by the minimum system study. If the study is not ready in time for Centra's next general rate application, Centra is to retain the existing 67% Demand and 33% Customer classification split for its distribution mains.

The Board accepts Atrium's evidence that the minimum system method is the most frequently used distribution classification method for North American utilities and would be the most appropriate approach for Centra. In the Board's view, because the minimum system approach incorporates actual cost data, it is a better tool than the diameter-length approach even if, as indicated by Centra, the study requires a number of assumptions to be made. The zero-intercept method was recommended by Atrium but not by any party



c) Module A of the MISO Tariff defines On Peak as "Period of time between Hour –ending 0700 EST and including Hour-ending 2200 EST Monday through Friday excepting New Year's Day, Memorial Day, Fourth of July, Labor Day, Thanksgiving Day, and Christmas Day or if the holiday occurs on a Sunday, the Monday immediately following the holiday." The time periods used for the proposed billing demand definition and the MISO Tariff definition differ in the amount of hours included in the on-peak periods as well as the treatment of weekends and holidays. Manitoba Hydro is proposing to use a shorter peak period reflective of the more constrained hours on its system and is proposing to treat weekends and holidays the same as weekdays in the interest of simplicity.

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GSS/GSM submits that DSM provides a public benefit of avoided system peak demand costs and therefore costs associated with DSM should be shared by all customers.

Board Findings

The Board finds that DSM costs should be functionalized as 100% Generation. DSM should be classified with the other Generation assets based on system load factor, and allocated on Winter Coincident Peak for the Demand portion and unweighted energy for the Energy portion. The Board finds that DSM is a Generation resource: it avoids Generation costs, rather than the costs of Transmission and Distribution. Within the customer classes, there are non-participants in DSM programs which support this approach over Manitoba Hydro's direct assignment of the costs.

Because DSM is treated as a system resource and the Curtailable Rate Program ("CRP") revenue requirement is no longer directly assigned to participating classes, there is no special treatment needed for the discrepancy between the revenue requirement cost of the CRP and the credit applied to the CRP customer classes.

DSM programs may appear similar to customer service programs such that the costs should be allocated or assigned to individual customer classes on a cost causation basis. The Board finds that, because DSM is a system resource, assigning DSM costs to individual classes is not warranted.

Historical Excess Energy Prices

Effective Date	Excess energy price ($/kWh)
2022 April 1	$0.05079
2021 April 1	$0.02403
2020 April 1	$0.02949
2019 April 1	$0.03949
2018 April 1	$0.03253

No, the excess energy price is not directly comparable/related to Manitoba Hydro's marginal value of generation. The excess energy price is an energy only value based on recent market price history. The marginal value of supply includes an energy value plus capacity values for generation, transmission and distribution and is based on future price and cost projections.

d) The updated 30 year levelized marginal and the annual marginal values based on general rate application assumptions are provided below. The 2022 spring energy price forecast was used for this analysis.

30 Year Levelized Marginal Values (Cents/kWh, CAD)		
Dollar Year	2021$	2022$
Generation	4.85	4.94
Transmission	0.29	0.30
Distribution	0.54	0.55
Total	5.69	5.80

Basic Marginal Costs Applicable to Distribution Level Programs
Marginal Costs Given at Distribution
(Constant Year 2022 Canadian Dollars)

5a

Notes:
- Marginal costs based on a uniform supply with a 100% capacity factor
- Marginal costs referred to distribution (loss factor of 4.82% to translate back to High Voltage Level)
- US/Cdn Exchange Rates and Escalation Factors (P911 January 11, 2022)
- Updated transmission (2019) & distribution (2019) marginal costs

Fiscal Year	SUMMER		WINTER					ALL-IN		
	Generation Energy	Generation Capacity	Generation Energy	Generation Capacity	Transmission Capacity	Distribution Capacity	Total Capacity	SUMMER	WINTER	ANNUAL
	$/MWh	$/kW/Yr	$/MWh	$/kW/Yr	$/kW/Yr	$/kW/Yr	$/kW/Yr	$/MWh	$/MWh	$/MWh
2024/25	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2025/26	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2026/27	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2027/28	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2028/29	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2029/30	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2030/31	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2031/32	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2032/33	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2033/34	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2034/35	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2035/36	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2036/37	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2037/38	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2038/39	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2039/40	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2040/41	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2041/42	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2042/43	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2043/44	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2044/45	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2045/46	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2046/47	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2047/48	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2048/49	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2049/50	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2050/51	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2051/52	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2052/53	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
2053/54	[redacted]	[redacted]	[redacted]	[redacted]	26.33	48.38	[redacted]	[redacted]	[redacted]	[redacted]
Levelized Cost at 3.70% Discount Rate	[redacted]	[redacted]	[redacted]	[redacted]	**26.33**	**48.38**	[redacted]	[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]	[redacted]	[redacted]			Levelized Value (Cents/kWh)			5.8

REFERENCE:

Coalition/MH I – 145

PREAMBLE TO IR (IF ANY):

MH states:

> “Efficiency considers whether price signals correspond with underlying embedded and marginal costs - Rate differentials increase alignment with embedded cost causation.”
>
> “Manitoba Hydro uses an embedded cost of service study as the basis for determining cost causation since the revenue requirement is based on embedded costs; determining the revenue to collect from each class or the rate differentiation required to collect that revenue based on marginal costs would fail to recover the cost of providing service to customers. In consideration of rate design, marginal costs are effective when used as a directional guideline for elements of the rate structure where it is desirable and feasible to incorporate a price signal.”
>
> “Manitoba Hydro is unable to comment on whether the rate differentials or other rate proposals increase or decrease alignment with marginal costs as the marginal values based on the current GRA are currently under development as noted in PUB/MH I-43d).”

QUESTION:

d) Please provide an updated Figure 8.14 – Marginal Cost Evaluation filed as part of the 2017/18 GRA, May 17, 2017, Tab 8, page 31 based on the most currently available data.
   i. Please prepare the schedule as requested in Coalition/MH I – 145 d based on the most current information.

RESPONSE:

Manitoba Hydro has provided the updated Marginal Values in the requested format. The values can provide a directionally relevant comparison to average embedded rates but direct comparison of levelized marginal values to average domestic revenue per kWh must consider the differences between the two figures.

- The levelized marginal values include both energy and capacity costs, with capacity costs converted to an energy equivalent. Class coincident peak load factors vary from a low of 51% to a high of 97% in PCOSS24, while the non-coincident peak load factors fall in the range of 46-72% for distribution-level classes. The adjustment for class load factors for Transmission and Distribution in the response to part (d-i) partially improves the comparison of the values to average revenues by class.
- The levelized marginal values allow differentiation of the costs between classes generally considered to be served at the transmission and distribution level but does not reflect that classes receive service at subtransmission, primary distribution and secondary distribution voltage levels and pay rates that reflect these distinct service levels.
- Operating costs are not included in the calculation of levelized costs but are one of the costs that must be recovered via domestic rates.
- The levelized marginal values exclude any customer service costs. These costs vary by customer class but are proportionally higher for smaller customers than large customers and are another cost that must be recovered via domestic rates.
- The levelized marginal values for Generation and Transmission do not incorporate the additional losses that are incurred serving a distribution level class, nor the differential losses that vary with specific service voltage for the class.
- The method of reconciling marginal costs to embedded costs could dramatically change the interpretation of the MC results

The following table is an update to Figure 8.14 from the 2017/18 & 2018/29 GRA incorporating class revenues and RCCs from PCOSS24, and the 30-Year Levelized Marginal Values for 2022 from Manitoba Hydro's response to PUB/MH I-43d (Updated) which are the most current values available.

	Levelized Marginal Value (¢/kWh)				Avg Rev	Rev/Cost	2008	PCOSS24
	Gen	Trans	Dist	Total	¢/kWh		MC[1]	RCC
Residential	4.94	0.30	0.55	5.80	10.27	177.1%	72.8%	94.4%
GSS ND	4.94	0.30	0.55	5.80	10.32	177.9%	79.8%	109.7%
GSS D	4.94	0.30	0.55	5.80	8.81	151.8%	65.7%	101.8%
GSM	4.94	0.30	0.55	5.80	7.97	137.4%	59.3%	100.3%
GSL 0-30	4.94	0.30	0.55	5.80	6.66	114.9%	50.6%	97.9%
GSL 30-100	4.94	0.30		5.24	5.54	105.7%	46.7%	112.4%
GSL >100	4.94	0.30		5.24	5.13	97.9%	46.7%	113.2%

The following table has been prepared consistent with the request in COALITION/MH I-145d using class revenues and Coincident Peak demand load factors from PCOSS24, and the 30-Year Levelized Marginal Values for 2022 from Manitoba Hydro's response to PUB/MH I-43d (Updated) which are the most current values available.

	Marginal Cost (cents/kWh @ 100% LF)			Class CP	Marginal Cost Trans & Dist @ Class LF (cents/kWh)					
Class	Gen	Trans	Dist	LF from PCOSS24	Gen	Trans	Dist	Total	Avg Rev (cents/kWh)	Rev/MC %
Residential	4.94	0.30	0.55	50.9%	4.94	0.59	1.08	6.61	10.27	155.4%
GSS ND	4.94	0.30	0.55	59.7%	4.94	0.50	0.92	6.36	10.32	162.2%
GSS D	4.94	0.30	0.55	62.6%	4.94	0.48	0.88	6.30	8.81	139.8%
GSM	4.94	0.30	0.55	73.0%	4.94	0.41	0.75	6.10	7.97	130.5%
GSL 0-30	4.94	0.30	0.55	80.3%	4.94	0.37	0.69	6.00	6.66	111.1%
GSL 30-100	4.94	0.30		91.8%	4.94	0.33		5.27	5.54	105.2%
GSL >100	4.94	0.30		94.4%	4.94	0.32		5.26	5.13	97.5%

[1] Exhibit 68, 2008 GRA

This finding is a marked change from the earlier rationale applied by the Board, that DSM was solely of value as a generation function.

The Board's finding in the EM 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[116]:

> 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.

It is important to recognize as well that this blended marginal value is used by EM throughout the programming assessment. The marginal values then cited by EM were 7.33 cents/kWh[117] comprising a combined generation, transmission, and distribution benefit. However, this is not necessarily comparable to the marginal values typically cited by Hydro, as Hydro's marginal values are for a hypothetical defined load shape, while the EM values are for the specific load characteristics of the programs proposed, which would be expected to skew towards higher value periods. It is helpful to note that the last publicly available Marginal Values from Manitoba Hydro as of the EM hearing were from the 2017/18 & 2018/19 GRA:[118]

30 Year Levelized Marginal Values
[cents/kWh]

	Used in 2016 DSM Plan		2017/18 Marginal Value in 2017 $	Change From 2015/16 to 2017/18
Components	2015/16 Marginal Value in 2016 $	2015/16 Marginal Value in 2017 $		
Generation	6.34	6.34	4.39	- 32%
Transmission	0.56	0.57	0.57	0.0%
Distribution	0.87	0.89	0.78	-12%
Total	7.77	7.94	5.75	-28%

The use of these values indicated a potential distribution of DSM benefits of approximately 10% to transmission, 15% to distribution, and 75% to generation. The marginal values have now been updated for this proceeding, as follows[119]:

[116] Daymark/EM I-20a.
[117] Efficiency Manitoba Three-Year Plan, pdf page 134 of 591.
[118] PUB/MH II-57 (Revised) dated 2017-12-18 from the 2017/18 & 2018/19 GRA.
[119] PUB/MH-I-43d (Updated).

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8.3.2 Results of PCOSS24 show Five Classes Are Outside the ZOR

In Manitoba, to the extent that an RCC for an electricity customer class falls within the range of 95% to 105%, referred to as the zone of reasonableness or "ZOR", it is accepted that its revenues are recovering the allocated cost.

Changes in class RCCs in PCOSS24 are consistent with the directional impact expected due to the large increase in NER since PCOSS21. The increased NER has resulted in a shift in costs such that Generation and Transmission represents 64% of revenue requirement in PCOSS24 compared to 71% in PCOSS21. Cost shifts of this nature tend to decrease the RCC of distribution-level customer classes and increase it for the GSL classes that are served directly off the transmission system. RCC results for PCOSS24 are included in Figure 8.3, results of PCOSS21 have been included for comparative purposes.

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

8.3.3 A Lighting Cost of Service Study was Prepared to Evaluate Sufficiency of Individual Lighting Rates

Periodically, a Lighting Cost of Service Study is required to evaluate and adjust specific lighting rates rather than the lighting class as a whole.

In this application, PCOSS24 assesses the sufficiency of rates for the entire A&RL class and the 2024 Lighting Cost of Service Study ("LCOSS24") takes the costs assigned to the class from

8.4.2 Proposed Rate Changes Move Customer Class RCCs Towards the ZOR

Determining the proposed rate increases by class requires reasoned judgment in addition to being guided by the results of a cost of service study. Manitoba Hydro's rate proposals consider the rate objectives noted in Section 8.4, each class's relative variance from unity in PCOSS24, past RCC results and progress towards the ZOR, as well as past direction from the PUB, discussed further below.

Manitoba Hydro's proposed rate increases by class are included in Figure 8.5. Manitoba Hydro's overall approach moderates the level of impact to the classes receiving above average increases while still providing a meaningful level of movement to bring classes with RCCs greater than 105% back into the ZOR.

Figure 8.5 Proposed Rate Increases by Class

Customer Class	Proposed Class Rate Increase September 2023	Proposed Class Rate Increase April 2024
Residential	2.4%	2.4%
GSSND	1.0%	1.0%
GSSD	2.1%	2.1%
GSM	2.1%	2.1%
GSL 750-30kV	2.1%	2.1%
GSL 30-100kV	1.5%	1.5%
GSL >100kV	1.5%	1.5%
Area & Roadway Lighting	1.0%	1.0%

Based on the results of PCOSS24, the RCCs for the GSSND, GSL 30-100kV, GSL >100 kV and the AR&L classes are above the ZOR, while the RCC for the Residential class is below the ZOR, which suggests these classes receive a rate increases that differ from the average. In addition to RCC results, Manitoba Hydro also considered the following factors before determining the proposed level of rate differentiation to apply to each class:

- The RCC for the GSSND class has been persistently above the ZOR (all studies since PCOSS13) and Manitoba Hydro has been attempting to bring the class RCC down with successive below average increases since 2018. Manitoba Hydro is proposing that the

PUB Advisor Document - Combination of Figures 8.3 and 8.5 of MH 2023/24 & 2024/25 GRA

Customer Class	PCOSS21 RCCs		PCOSS24 RCCs		Proposed Class Rate Increase September 2023	Proposed Class Rate Increase April 2024
Residential	96.2%	In	94.4%	Below	2.4%	2.4%
GSS – ND	113.8%	Above	109.7%	Above	1.0%	1.0%
GSS – D	104.0%	In	101.8%	In	2.1%	2.1%
GSM	99.3%	In	100.3%	In	2.1%	2.1%
GSL 750V-30KV	95.6%	In	97.9%	In	2.1%	2.1%
GSL 30-100kV	103.7%	In	112.4%	Above	1.5%	1.5%
GSL >100kV	101.2%	In	113.2%	Above	1.5%	1.5%
A&RL	123.3%	Above	108.2%	Above	1.0%	1.0%
	Source: Tab 8 (p. 9) - Figure 8.3				*Source: Tab 8 (p. 12) - Figure 8.5*	

2025/26, the current proposals are wholly insufficient for this purpose. The analysis for this conclusion is provided in Manitoba Hydro's response to IRs, as follows[131]:

Table 4-5: Rate Adjustments Needed to Achieve ZOR within 5 years and 10 years

	PCOSS24 RCC ratio	Current Rate Increase Proposal per year	Rate Adjustment needed to get to 95%-105% by 2027/28	*difference*	Rate Adjustment needed to get to 95%-105% by 2032/33	*difference*
Residential	94.4%	2.4%	2.4%	*0.0%*		
GS Small Non-Demand	109.7%	1.0%	1.1%	*(0.1%)*		
GS Small Demand	101.8%	2.1%	2.4%	*(0.3%)*		
GS Medium	100.3%	2.1%	2.4%	*(0.3%)*		
GS Large 0-30 kV	97.9%	2.1%	2.4%	*(0.3%)*		
GS Large 30-100 kV	112.4%	1.5%	0.6%	*0.9%*	1.3%	*0.2%*
GS Large 100+ kV	113.2%	1.5%	0.5%	*1.0%*	1.2%	*0.3%*
Area and Roadway Lighting	108.2%	1.0%	1.4%	*(0.4%)*		

As noted in the above table, Hydro's current rate proposals will largely achieve the ZOR within 5 years (2027/28) for all classes, with the exception of the industrial classes of GSL 30-100 kV and GSL >100 kV. Specifically, the GSS Non-Demand can be brought to within the ZOR with five years of 1.1% rate increases (based on the overall average increases being 2.0%), but Hydro has proposed 1.0%. Similarly, the Area and Roadway Lighting class can be brought down to the ZOR with 1.4% increases, while Hydro has proposed 1.0%. In both these cases, the PUB's 10-year target from Order 59/18 is projected to be achieved.

However, for the two largest industrial classes, the rate increases would need to be 0.5% and 0.6% respectively per year for five years, but Hydro has proposed 1.5% per year for each. The right-hand side of the table further notes that the current 1.5% proposal is even too high to achieve the ZOR by 2032/33, or more than fifteen years after the Board's direction in Order 59/18.

Clearly to achieve the ZOR by 2025/26 consistent with the new provisions of the *Manitoba Hydro Act* will take even further differentiated rate proposal than shown under the 2027/28 scenario. Also note that in all cases, the increases needed to the customers who would receive above average increases, in order to permit the industrial classes to get within the ZOR, remain well below the 3.6% per year increases that Hydro first proposed in the current application, so presumably remain well within the range of reasonable adjustments that can be imposed on customers.

It is also important to address clear misstatements by Hydro in respect of the rate proposal, as set out in Tab 8, as follows[132]:

> The General Service Large 750V-30 kV and >100 kV RCCs have trended above unity and towards the higher end of the ZOR in studies prepared since Order 164/16, however, given both classes had RCCs in the ZOR in PCOSS21, it is clear

[131] Data from Coalition/MH-I-143a-b.
[132] Manitoba Hydro Application, Tab 8, page 13.

- Hydro Quebec, 84% - 125%, with Residentials at 84%; and
- Manitoba Hydro,94.4%-113.2%, with no rate differentiation, Residentials at 94.4%.

Table 18:

BC Hydro RCCs (%)					**Hydro Quebec RCCs**	
	2013	**2014**	**2016**			
Residential	89.6	92.9	93.6		Residential	84%
GS<35kW	126.4	123.5	111.6		GSS ND < 65 kW	125%
MGS	120.9	119.5	120.5		GS Medium (demand) > 50 kW	125%
LGS	102.2	101.5	100.8		GS large (demand) > 5000 kW	125%
Irrigation	85.0	90.3	84.5		Large Industrials	116%
Streetlighting	112.0	129.4	133.7			
Transmission	105.3	97.3	101.4			
Manitoba Hydro RCCs	**PCOSS24**	**2028/29**				
Residential	94.4%	95.5%				
GSS ND	109.7%	110.5%				
GSS D	101.8%	102.4%				
GSM	100.3%	100.3%				
GSL 0-30	97.9%	96.7%				
GSL 30-100	112.4%	107.1%				
GSL>100	113.2%	106.8%				
ARL	108.2%	117.9%				

In fact, MH's RCC coverage compares quite favourably relative to these other electric utilities despite the doubling of Manitoba Hydro's balance sheet in the last 10 years as a result of the in-service of the major capital projects, significant RCC volatility year over year, and in the absence of rate differentiation.

As noted in Section 6.1, when NER levels return to more normal levels, the RCCs for the Residential class and the largest GSL classes will become even tighter with the expectation that the Residential class RCC will be in the ZOR. MH's rate differentiation proposals represent an overreaction to the mechanistic outcome of a one-year COS snapshot and do not consider the overall circumstances of a large vertically integrated utility like MH with common costs in the billions of dollars.

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Finance Expense and Finance Income

Finance Expense net of Finance Income is included in the Interest cost category of the COS and has been functionalized based on average Rate Base (**Table C1 and C2**).

PCOSS24 incorporates the 50% reduction in debt guarantee fees announced by the Provincial Government on November 23, 2022.

Depreciation and Amortization

The preliminary budget for 2023/24 includes $632 million of Depreciation and Amortization expense which is functionalized through the Corporation's accounting system for purposes of the COS. The Depreciation and Amortization expense in PCOSS24 reflects the most recent Depreciation Study which was completed in fiscal 2019/20.

Water Rentals and Assessments

Water Rentals, Fuel and Power Purchases continue to be functionalized as Generation in the PCOSS, as shown in **Table D1**.

PCOSS24 incorporates lower levels of Water Rental fees than PCOSS21 due to the amendment to reduce Water Rentals fees by 50% announced by the Provincial Government on November 23, 2022.

Fuel and Power Purchased

Water Rentals, Fuel and Power Purchases continue to be functionalized as Generation in the PCOSS, as shown in **Table D1**.

In PCOSS24 the Power Purchases now include the amortization of the intangible asset and transmission charges associated with the Great Northern Transmission Line.

Capital and Other Taxes

Capital Tax has been functionalized on the basis of ending Rate Base as at March 31, 2024 as shown in **Table C3 and C4**.

Payroll Taxes, as well as communication and building-related Property Taxes, are functionalized on the basis of labour costs. The remaining Property Taxes on electric plant are functionalized in the PCOSS consistent with the function of the associated plant.

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PUB Advisor Document - Combination of Figures 8.3 and 8.5 of MH 2023/24 & 2024/25 GRA

Customer Class	PCOSS21 RCCs		PCOSS24 RCCs		Proposed Class Rate Increase September 2023	Proposed Class Rate Increase April 2024
Residential	96.2%	In	94.4%	Below	2.4%	2.4%
GSS – ND	113.8%	Above	109.7%	Above	1.0%	1.0%
GSS – D	104.0%	In	101.8%	In	2.1%	2.1%
GSM	99.3%	In	100.3%	In	2.1%	2.1%
GSL 750V-30KV	95.6%	In	97.9%	In	2.1%	2.1%
GSL 30-100kV	103.7%	In	112.4%	Above	1.5%	1.5%
GSL >100kV	101.2%	In	113.2%	Above	1.5%	1.5%
A&RL	123.3%	Above	108.2%	Above	1.0%	1.0%
	Source: Tab 8 (p. 9) - Figure 8.3				*Source: Tab 8 (p. 12) - Figure 8.5*	

Two other important considerations when determining the blocked energy rates for these customers is the role the Basic Charge and Demand Charge play on each subclass. The majority of customers are Small Non-Demand, hence increasing the Basic Charge, even minimally, will generate more revenue from this group of customers than the other two groups. With respect to Demand Charges, Small Non-Demand customers do not pay a Demand Charge; Medium customers, on the other hand, generate roughly 34% of their total revenue from demand charges, much higher than the 15% demand revenue received from Small Demand customers.

Over the past several rate changes, Manitoba Hydro has been applying less than average increases to the GSSND class while achieving close to the target revenue increases from the GSSD and GSM classes. Given the extent of the difference between the RCCs of the three classes it is not possible to get all classes within the ZOR while maintaining the harmonized rate structure.

8.7.3 Our Rate Proposals for the GSS and GSM Classes Reflect Manitoba Hydro's Rate Objectives

Manitoba Hydro has assessed the proposal to adjust GSM rates independently from GSS against its rate objectives in Figure 8.16.

Figure 8.16 Rate Objective Assessment of Rate Structure Proposal for GSS and GSM

Objective	Comment
Reflect the Cost of Providing Service: Rates ensure revenue requirement is recovered and target achieving class RCCs in the range of 95% - 105%	De-harmonizing the rates of the GSM and GSS classes will allow Manitoba Hydro to achieve the revenue requirement for each class.
Stability: considers the importance of customers having stable and predictable bills	Maintaining the existing declining block structure for GSS minimizes unexpected changes that could adversely affect existing customers.
Flexibility: considers ability of Manitoba Hydro to respond to future changes	Ceasing rate harmonization will allow greater agility in adjusting rate components to respond to changes in costs or to send price signals.

Proposed rates for the General Service Small class are included in Figure 8.17.

Figure 8.17 Proposed General Service Small Rates

	Approved Jan 2022 Rates	Proposed Sep 2023 Rates	Proposed Apr 2024 Rates
Basic Monthly Charge			
Single Phase	$20.74	$20.74	$20.74
Three Phase	$33.69	$33.69	$33.69
Energy Charge			
First 11,000 kWh	$0.09485	$0.09570	$0.09656
Next 8,500 kWh	$0.07277	$0.07550	$0.07833
Balance*	$0.04492	$0.04593	$0.04694
Demand Charge			
<50 kVA	No Charge	No Charge	No Charge
>50 kVA	$11.52	$11.81	$12.11

8.7.5 Proposed Rate Changes for the General Service Medium Class

The General Service Medium class includes establishments such as "big box" retail outlets, grocery stores, bulk-metered apartments, recreation facilities, universities, and institutional occupancies whose monthly billing demand exceeds 200 kVA per month and whose transformation is owned by MH.

As noted in Section 8.7.2, Manitoba Hydro is proposing to de-harmonize the General Service Medium rates from the General Service Small Non-Demand, and General Service Small Demand rate classes.

As part of this change, Manitoba Hydro is proposing to consolidate the first and second energy blocks resulting in the GSM class having a singular rate for the first 19,500 kWh of consumption of $0.08626 in 2023/24 and $0.08717 in 2024/25 as per Figure 8.18. The former third (now second) energy block has a proposed increase of 2.3%, as well as a 2.5% increase in the demand charge.

Figure 8.11 GSS / GSM Rate Structure

	GSSND	GSSD	GSM
Basic Monthly Charge			$33.69
Single Phase	$20.74	$20.74	
Three Phase	$33.69	$33.69	
Energy Charge			
First 11,000 kWh	$0.09485	$0.09485	$0.09485
Next 8,500 kWh	$0.07277	$0.07277	$0.07277
Balance*		$0.04492	$0.04492
Demand Charge			
<50 kVA	n/a	No Charge	No Charge
>50 kVA	n/a	$11.52	$11.52

8.7.1 We Are Proposing to Continue the Use of a Declining Block Energy Structure

The GSSND and GSSD classes have been served under a harmonized declining block energy rate structure since 1989, and the GSM class has been served under a harmonized declining block energy rate structure since 2008 (as well as prior to 1987). Manitoba Hydro's rate proposals for the GSS and GSM classes in this application continue to use a declining block structure in consideration of rate stability and customer bill impacts. The rationale for Manitoba Hydro's use of a declining block rate structure, which was requested by the PUB in Directive 28 of Order 59/18, is outlined below.

As discussed in Appendix 8.1 Section 1.1.2, costs are categorized as either customer, demand, or energy. Customer and demand costs are considered to be primarily fixed, while energy costs are considered to be variable in that they change as total output changes[5].

Rate structures in turn therefore generally reflect that some costs are fixed and some are variable, albeit to varying degrees.[6] Rate structures that have demand charges in addition to

[5] Manitoba Hydro has significant depreciation and interest costs related to hydraulic generation resources that were selected to provide energy at least cost, as well as to meet capacity requirements. The energy-related depreciation and interest expenses may be viewed as a fixed cost from a strict accounting perspective but are appropriately treated as volumetric for purposes of cost allocation and rate design.

[6] Rate structures may be intentionally designed to not fully reflect the breakdown of costs between customer, demand, and energy used in cost allocation. These decisions may be made out of administrative simplicity or to better align rates with marginal cost price signals. As an example, a utility may choose to recover demand related costs through energy rates for smaller customers who do not have the required demand meters in place and are typically less sophisticated consumers that may not be able to understand demand charges. Or alternatively

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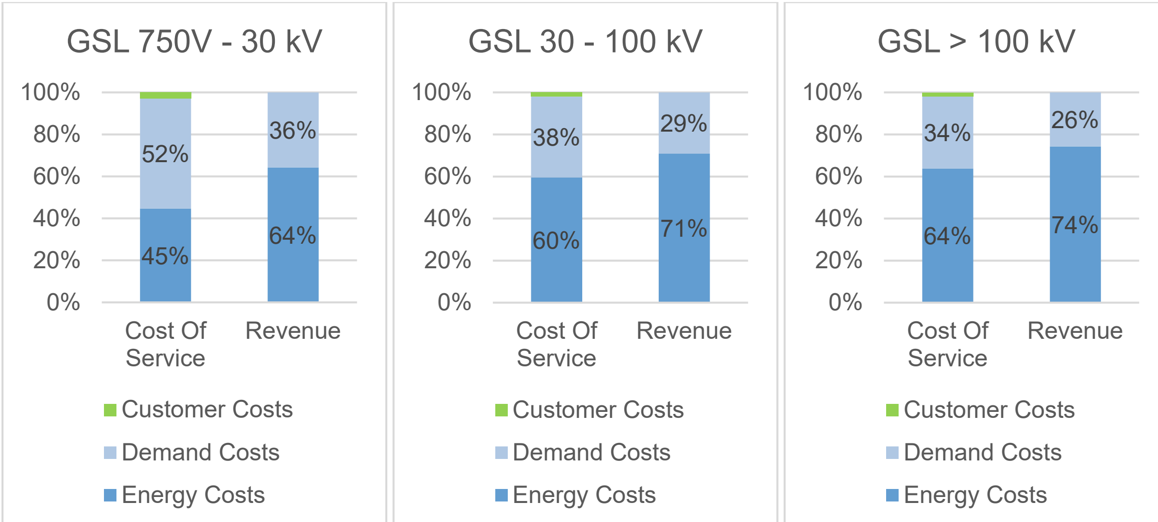
Figure 8.21 Comparison of Demand and Energy Costs vs Revenue Recovery



Manitoba Hydro has assessed the demand and energy rebalancing against its prioritized rate objectives in Section 8.8.3. The precise rebalancing being proposed for each GSL class, is discussed in the Sections 8.8.4 to 8.8.6.

8.8.2 We Are Proposing a More Refined Approach to Calculate Billing Demand for GSL >30 kV Customers

With interval metering in place Manitoba Hydro has the opportunity to refine the way monthly billing demand is calculated for the GSL 30-100 kV and GSL >100 kV classes in order to send a more refined price signal. Currently demand charges are levied based primarily on a customer's maximum measured demand in a month. This practice, although common across the utility industry, gives no consideration to when the overall system is peaking. As a result, there is a disconnect between the way costs are allocated to customers compared to how the costs are recovered. Manitoba Hydro is proposing to introduce a "peak" and "non-peak" consideration to the billing demand definition based on when Manitoba Hydro's system experiences its peak. Figure 8.22 shows the current and proposed approach for defining billing demand.

In addition, for rates effective April 1, 2024, Manitoba Hydro is proposing to adjust the billing demand definition as described in Section 8.8.2. The impact of this change results in an increase to the demand rate of $0.10 shown in Figure 8.28.

Figure 8.28 Impact of Billing Demand Definition Change – GSL 30-100 kV

Large 30-100 kV	Rate	Billing Determinants	Revenue
Monthly Demand Charge per kVA	$ 9.11 (1)	3,702,874 (2)	$33,733,182 (4) = (1) X (2)
Adjustment		98.9% (3)	
On Peak Billing Demand	$ 9.11 (1)	3,662,143 (5) = (2) X (3)	$33,362,123 (6) = (1) X (5)
Revenue Reduction			$371,059 (7) = (4) - (6)
Revenue Neutral Increase to Demand Rate	$ 0.10 (8) = (7) / (5)		
Total Demand Rate	$ 9.21 (9) = (1) +(8)		$33,733,182 (10) = (9) X (5)
Check			$0 (11) = (4) - (10)

As explained in Section 8.8.2 this above change is expected to have a negligible bill impact as the increase in billing demand charge will be predominantly offset by a reduction in measured demand for most customers.

8.8.6 Proposed Rate Changes for the General Service Large >100 kV Class

Manitoba Hydro is proposing to use the same approach for rates in the GSL >100 kV class as described for the GSL 750V-30 kV and 30-100 kV classes. An overall 1.5% increase in each of the test years applied entirely to the demand charge consistent with the priorities discussed in Section 8.8.1 to rebalance energy and demand charges. For the GSL >100 kV class this requires a 5.8%, and 5.5% increase to the demand charge effective in both September 1, 2023 and April 1, 2024 and reflected in Figure 8.29.

Figure 8.29 Proposed Rate Changes – GSL >100kV Class

	Approved Jan 2022 Rates	Proposed Sep 2023 Rates	Proposed Apr 2024 Rates
Energy Charge (per kWh)	$0.03766	$0.03766	$0.03766
Demand Charge (per kVA)	$7.36	$7.79	$8.31*

*The $8.31 proposed rate includes the 5.5% increase to the demand charge as well as the $0.09 rate impact related to the billing demand definition change described in Figure 8.31.

Figure 8.22 Billing Demand Definition

Current Definition	Proposed Definition
Billing demand is defined as the greatest of the following (expressed in kVA): a) measured demand; or b) 25% of contract demand; or c) 25% of the highest measured demand in the previous 12 months	Billing demand is defined as the greatest of the following (expressed in kVA): d) measured demand during Peak Hours; or e) 90% of measured demand during Non-Peak Hours; or f) 25% of contract demand; or g) 25% of the highest measured demand in the previous 12 months Where, Peak Hours are defined as all hours from 7:01 to 11:00 and 17:01 to 21:00 (Central Time Zone) in the months of January, February, March, April, May, September, October, November, and December; and all hours from 12:01 to 20:00 (Central Time Zone) in the months of June, July and August. Non-Peak Hours are defined as all hours from 0:01 to 24:00 (Central Time Zone) in the months of January to December, excluding Peak Hours.

The change in billing demand definition will result in customers' billing demand being the same or less than under the current definition. An analysis of the hourly loads for customers served at voltages > 30 kV show that the proposed change in billing demand definition will reduce the demand billing determinant to approximately 99% of billing demand under the current definition. Manitoba Hydro is proposing a slight increase to the demand charge to ensure the full revenue requirement continues to be recovered and maintain revenue neutrality for the classes. For most customers, the increase in the demand charge will be offset by the reduction in their measured billing demand resulting in negligible bill impacts. The impact of the billing demand definition change on the demand rates and overall demand revenue is shown in Figure 8.28 of Section 8.8.5 and Figure 8.31 of Section 8.8.6.

Manitoba Hydro is proposing to implement this change for the second test year, effective April 1, 2024. This will ensure that, if approved, Manitoba Hydro has sufficient time after receipt of the PUB's Order to communicate the change to customers and make the required adjustments to billing programming. The proposed change in the definition of billing demand has been incorporated in the 2024/25 Proposed Rate Schedule found in Appendix 8.7.

8.8.3 Our Rate Proposals for the GSL Classes Reflect Manitoba Hydro's Rate Objectives

Manitoba Hydro has assessed the GSL rate proposals related to demand changes against its rate objectives in Figure 8.23.

Figure 8.23 Rate Objective Assessment – Demand Changes

Objective	Comment
Reflect the Cost of Providing Service: Rates ensure revenue requirement is recovered and target achieving class RCCs in the range of 95% - 105%	Manitoba Hydro's proposals to rebalance the recovery of costs between energy and demand rates will be done on a revenue neutral basis with proposed rates set to recover forecast revenue requirement. Manitoba Hydro is proposing that the revenue reduction from the reduction in billing determinants be offset by a slight increase to the demand charge in order to remain revenue neutral and recover the entirety of the proposed revenue requirement.
Stability: considers the importance of customers having stable and predictable bills	Improves bill predictability and stability as a lesser portion of the customer's bill is variable.
Flexibility: considers ability of Manitoba Hydro to respond to future changes	Rate proposal does not impede future flexibility.
Efficiency: considers whether price signals correspond with underlying embedded and marginal costs	Improves alignment with embedded cost of service

RATIONALE FOR QUESTION:

To fully understand the definition of on-peak, and context surrounding it.

RESPONSE:

a) Manitoba Hydro's proposal to adjust the definition of billing demand introduces a time-varying component to reflect that capacity on the system is more constrained in certain hours, as well as provides customers with the opportunity to manage their bills in a relatively low-risk manner. The inclusion of a provision for billing demand based on 90% of measured demand in non-peak hours is a measure of prudency and serves to avoid potential unintended consequences to Manitoba Hydro's system and / or costs, of unchecked load growth in hours defined as non-peak, that is unlikely but still possible. Inclusion of a consideration for non-peak demand in the definition of billing demand is consistent with the practice of other jurisdictions that have similarly time-structured demand rates.

b) Manitoba Hydro's proposed demand billing definition for peak hours was based on the observed maximum hourly loads on Manitoba Hydro's system. The table below shows a visual representation of the maximum demands in each hour relative to the other hours. For winter, dark red represents hours with the lowest peak, transitioning to dark blue which represent those hours with the highest peaks. For summer, dark yellow represents hours with the lowest peak, transitioning to dark green which represent those hours with the highest peaks.

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