1

Tab #	Description	Reference
Cost of Service		
106.	*Implementation of Order 164/16*	***Order 164/16, pp. 80-81; MIPUG/MH I-11a; Tab 8, p. 13; Order 164/16, p. 77; PUB/MH I-147 & I-148; PUB/MH I-150; Harper p. 67; 2016 COSS MH Final Submission on Oral Evidence Issues, p. 22; PUB/MH I-144; Tab 8, p. 6; 2016 COSS MH Final Submission on non-Oral Evidence Issues, p. 3; Order 164/16, pp. 47-49; PUB/MH II-45, pp. 19, 21-26; Tab 8, p. 10***
107.	*Revenue to Cost Coverage - Zone of Reasonableness*	***Tab 8, pp. 32-34; Bowman pp. 7-13 to 7-14; PUB/MH I-137, II-87 & II-88***
108.	*Revenue to Cost Coverage – Calculation Results*	***Order 164/16, pp. 36-38; GSS-GSM/MH I-9; MIPUG/MH I-23b***

Tab #	Description	Reference
Rate Design		
109.	*MH Application and Ratemaking Principles*	***Tab 1; Tab 9, p. 2; Coalition/MH I-119***
110.	*Differentiated Rates and Marginal Cost*	***Bowman p. 1-7; Bowman p. 7-14; PUB/MH I-131; Tab 8, p. 31***
111.	*Recent History of Rate Design*	***February 5, 2016 MH Response to COSS Scope; Order 26/16 p. 16***
112.	*Residential Electric Space Heating*	***Home Space Heating Costs (Nov 2017); PUB/MH I-129; PUB/MH II-93; Coalition/MH I-129b; Appendix 9.14, p. 19***

VOLUME 5

113.	*Alternative Rate Design – Manitoba Hydro Electric Space Heating*	***Appendix 9.14, pp. 12-14; Advisor Document based on PUB-MH II-58a; Centra 2013/14 GRA Appendix 3.1***
114.	*Alternative Rate Design – Inverted Block Rates*	***Chernick p. 38; PUB/GAC 1-5 (Revised); MH/GAC 10***
115.	*Alternative Rate Design – Time of Use Rates*	***Tab 8, p. 28; MIPUG/MH I-5a (Attachment) pp. 7-12; MH Rebuttal p. 71***
116.	*Bill Affordability & Alternative Rate Design*	***PUB MFR 72 (Revised), pp. 288-289; Order 73/15, pp. 27-30 & 96; Appendix 10.5, p. 41; Appendix 10.7; Appendix 10.5, pp. 77-78; AMC/MH II-23a, p. 6; AMC/MH II-23a, pp. 11-13; Advisor Document based on AMC/MH II-23a; Appendix 10.5, p. 17; AMC/MH I-6a-c***
117.	*Other Rate Programs and Options*	***Tab 9, pp. 9-13; Appendix 10.1; 2016 Interim Supplemental Attachment 9, p. 25***

106

Community Relations, Service Extensions, Load Research, and other departments. Manitoba Hydro's C10 allocator is based on estimates of the time and efforts various departments devote to each customer class, which are then weighted by the budget for each area. The costs within Consumer Consultation and Information include costs related to Key Accounts and Major Accounts, which apply to larger customers such as GSL customers, as well as a generic Customer Service category.

Manitoba Hydro has agreed to review the C10 allocator but is of the view that GSL customers should not be excluded from the Customer Service costs category in advance of this review.

Intervener Positions

MIPUG's expert witness identifies $1.2 million of Customer Service costs in PCOSS14 that, in his view, are incorrectly attributed to the GSL 30-100kV and GSL >100kV classes. MIPUG does not agree that the costs within the generic Customer Service sub-category of Consumer Consultation and Information, such as line locates, safety watches, consumer consultations, building moves, and education and safety, apply to GSL customers. MIPUG argues that, since the $1.2 million in Customer Service costs do not apply to GSL customers, these costs should not be allocated to them.

Board Findings

The Board finds that costs in the Customer Service sub-category within the Customer Consultation and Information category should not be allocated to GSL 30-100kV or GSL>100kV customers unless and until Manitoba Hydro can provide a fulsome description of these costs. In this description, Manitoba Hydro shall:

- explain why these costs apply to the GSL classes,
- confirm that these costs are not already subsumed within the costs categorized as Key Accounts and Major Accounts, and

* justify why the customer weightings for the allocator, which provide greater weighting to GSL customers, are appropriate for these costs.

Allocation of Other Customer Services Costs

Manitoba Hydro's Position

Manitoba Hydro has agreed to update the customer weighting factors within its Customer Service allocators as time and resources allow.

Intervener Positions

The Coalition, GAC, and MIPUG each recommend that Manitoba Hydro update or provide additional support for various customer weightings. The allocation approach for these costs was not contentious in this proceeding and no intervener proposed alternative allocation methodologies.

Board Findings

The Board finds that, with the exception of the costs in the Customer Service sub-category of Customer Consultation and Information allocated to GSL >30kV classes, Manitoba Hydro's Customer Services allocators are appropriate for the allocation of Customer Services costs. The weightings used to allocate the Customer Services costs, such as for meter reading, billing, and collections, shall be updated.

7

REFERENCE:

Tab 8, Pages 13 and 18

PREAMBLE TO IR (IF ANY):

QUESTION:

a) With reference to PCOSS18, pages 18-19, for each row on the 2 pages please provide a break down by class of the noted costs.
b) With respect to the C10 Customer Service table at page 18 of PCOSS18, please provide a discussion on each row (totalling $13.9 million) as to why the costs are not predominately if not entirely related to distribution service.
c) Does Manitoba Hydro "Line Locates" service play a role in locating transmission lines, or primarily distribution lines? Please provide a breakdown of locates by transmission versus distribution.
d) Please provide a breakdown of the $3.1 million in costs that Hydro incurs for building moves and overseeing work near electric plant (PCOSS18, page 18). What costs does this represent? Are these activities performed on a cost-recovery basis?
e) Does Manitoba Hydro incur costs for "building moves and oversight of work conducted near electric plan" related to transmission plant, or does this only (or at least predominately) apply to activities that are in the vicinity of distribution lines?
f) Please provide a description of the $1.2 million in "Call Center Outage Calls" (PCOSS18, page 18) indicating the type of costs and what activities are performed by the call center. Is the call center not primarily oriented to serving distribution level customers, with transmission connected customers receiving their customer service contacts through the Industrial and Commercial Solutions group?

RATIONALE FOR QUESTION:

RESPONSE:

a) The following table provides details on the allocation of Customer Service costs broken down by class.

Customer Service Activity		Res	GSS ND	GSS D	GSM	GSL 0-30kV	GSL 30-100 kV	GSL >100kV	A&RL	Total
		Class Share of Operating ($ million)								
C10	Education & Safety	0.52	0.12	0.13	0.16	0.08	0.06	0.15	0.02	1.2
C10	Contact Center - Outages	0.51	0.12	0.12	0.16	0.08	0.06	0.15	0.02	1.2
C10	Rates & Regulatory	1.25	0.29	0.30	0.40	0.19	0.14	0.37	0.04	3.0
C10	Marketing R&D	0.56	0.13	0.13	0.18	0.08	0.06	0.17	0.02	1.3
C10	Line Locates	1.70	0.39	0.41	0.54	0.25	0.20	0.51	0.06	4.1
C10	Building Moves & Safety Watches	1.28	0.29	0.31	0.41	0.19	0.15	0.38	0.05	3.1
C23	Industrial & Commercial Solutions	-	-	-	-	1.14	0.89	2.29	-	4.3
C13	Customer & Community Service Work	2.33	0.54	0.57	0.74	-	-	-	0.08	4.3
C13	General Inquiries	1.11	0.25	0.27	0.35	-	-	-	0.04	2.0
C13	Power Quality	0.57	0.13	0.14	0.18	-	-	-	0.02	1.0
C13	Service Extensions	7.62	1.75	1.84	2.41	-	-	-	0.27	13.9
C11	Adjustments & Complex Billing	1.91	0.21	0.05	0.04	0.01	0.00	0.00	0.01	2.2
C11	Customer Accounts	0.59	0.06	0.01	0.01	0.00	0.00	0.00	0.00	0.7
C11	Field Billing	6.21	0.67	0.16	0.14	0.03	0.00	0.00	0.02	7.2
C11	CIS Admin	0.99	0.11	0.03	0.02	0.00	0.00	0.00	0.00	1.2
C11	Administrative	8.94	0.97	0.23	0.21	0.04	0.01	0.00	0.03	10.4
C12	Collections	10.68	0.83	0.19	0.03	-	-	-	-	11.7
C14	Inspections	1.29	1.69	0.40	0.07	0.01	0.00	0.00	-	3.5
C15	Meter Reading	8.62	1.12	0.54	0.09	0.01	0.00	0.00	-	10.4
Total		56.7	9.7	5.8	6.1	2.1	1.6	4.0	0.7	86.7

b) The activities listed on page 18 as C10 Customer Service General costs continue to be functionalized as Distribution Service in PCOSS18. Manitoba Hydro assumes the question was intended to seek clarification why the costs are not predominately if not entirely related to customers served at the distribution level.

The services included in this subfunction are not provided for the specific benefit of individual customers or class of customers, rather they are for the public good and applicable to all customer classes.

- Inspections
- Meter Reading

Schedules 4.3 to 4.7 provide the detail of the cost makeup for each sub-function, which has in some cases been further categorized, the allocator, as well as the results.

Customer Service and Industrial & Commercial Solutions

General Customer Service activities previously aggregated and allocated through what has been referred to as the "C10" allocator have been disaggregated. The activities now reflected in this General category are those activities that Manitoba Hydro views as public safety-related, the costs of which are allocable to all customers. This includes the costs associated with outage calls, line locates, marketing research and development, safety watches, building moves, and rates and regulatory. These general customer service activities have been allocated to all customer classes proportionately by revenue by class.

A number of other general customer service activities aimed at smaller customers including disconnects/reconnects associated with customer maintenance, general inquiries, power quality issues, as well as service extension activities have been pooled and allocated to classes excluding GSL.

The costs of the Industrial and Commercial Solutions departments have been allocated only to GSL classes on the basis of each GSL class's revenue, as the activities and services of these departments are dedicated to these classes.

Manitoba Hydro is generally unsupportive of a straight un-weighted customer count allocation and has limited its use. The overwhelming dominance of the number of residential customers would result in no cost distinction between customer classes. A revenue allocator, specifically applied as discussed above, recognizes intuitively that the cost of providing these services increases as the size of the customer increases and results in the same allocated cost by class as a percentage of their total bill.

Residential, General Service Small (GSS), and General Service Medium (GSM) customers. Thus, the Residential customer count used in the allocation of service drops is reduced by 87.34% of the 103,000 customers, or 89,959 customers. Reductions are calculated for the GSS and GSM classes using the same methodology.

Similarly, GAC recommends that Manitoba Hydro reflect these shared service drops in its next PCOSS filing. GAC also identifies that some of the weighting factors do not appear to be based on actual cost data. GAC also states that Manitoba Hydro rejects proposed changes to its methodology when they have too large an effect on the RCCs of the some classes, while rejecting proposed improvements that would have only a small effect on the COSS results, such as improving the Service Drop allocator.

Board Findings

The Board finds that an allocator that reflects the number of services drops, not the number of customers, better reflects cost causation. This will avoid potentially over-allocating costs to classes with multiple customers served by single service drops. The Board directs Manitoba Hydro to update its Service Drops cost allocator.

In the interim, until Manitoba Hydro updates its Service Drops allocator, the methodology used should prorate the 103,000 Residential customers over the three classes based on the number of customers in each class. This is more substantiated than Manitoba Hydro's method and it is calculated using current customer numbers.

As part of its comprehensive update of the Service Drops allocator, Manitoba Hydro shall revisit the weightings for GSS, GSM, and GSL 0-30kV 3-phase services. The updated analysis should show evidence that the weightings more accurately weight the cost differences between services drops for different customer classes. Due to the Board's decision to classify these costs as 100% Demand, there are no longer any Customer-related poles and wires costs. Therefore a similar adjustment to the allocation of Customer-related costs for distribution poles and wires is no longer required.

REFERENCE:

Tab 8, Appendix 8.1, Schedule 4.2

PREAMBLE TO IR (IF ANY):

Please refer to Schedule 4.2 of Appendix 8.1 of the submitted general rate application, which describes allocator C27 for service drops.

QUESTION:

a) Did Manitoba Hydro review the allocation of service drops prior to PCOSS18? If so what were its findings? If not, why not?
b) If Manitoba Hydro intends to review this allocator in the future, please provide an estimate of when this review will be complete.

RATIONALE FOR QUESTION:

RESPONSE:

a) In PCOSS18 the service drops allocator included the interim adjustment to recognize that multiple customers may be served from a single service as directed in Order 164/16 Directive 1 v). The weighting factors used were consistent with previous studies, and have not been reviewed or updated since the issuance of Order 164/16.

b) Please see Manitoba Hydro's response to PUB/MH I-150 which discusses Manitoba Hydro's plans to address further studies as directed in Order 164/16.

REFERENCE:

Tab 8, Appendix 8.1, page 18

PREAMBLE TO IR (IF ANY):

Please refer to page 18 of Appendix 8.1 of the submitted general rate application, which shows that allocators for general customer service costs are based on revenues.

QUESTION:

Why is revenue allocation more appropriate than either of the following:

a) Functionalization, classification, and allocation as common costs?
b) An internal allocator based on total customer-related operating expenses, or a subset thereof?

RATIONALE FOR QUESTION:

RESPONSE:

a) Manitoba Hydro agrees that many of the activities included in the General Customer Service category could reasonably be viewed as common costs. The revenue based allocation was selected, in part, since it produces a cost allocation similar to common costs functionalized in proportion to labour.

   The revenue based allocation offers the benefit of explicitly demonstrating the amount of general customer service costs allocated to each class. This transparency would not be possible if the services were treated as common costs, without making significant structural changes to the existing allocation model.

b) In PCOSS18 Customer related Operating expenses are limited to Billings, Collections, Meter Reading, Inspections, Meter Investment and Service Drops. Despite the use of weighting factors for these costs, an internal allocator based on them will still result in an allocation of General Customer Service costs largely driven by customer count which does not adequately recognize that the cost of providing service increases with the size of the customer.

REFERENCE:

Board Order 164/16

PREAMBLE TO IR (IF ANY):

QUESTION:

Please describe Manitoba Hydro's progress with regard to compliance with Board directive 1 (gg) in Order 164/16, which states: "Manitoba Hydro shall study the allocation of common costs and develop allocators that are more directly related to the causes of the common costs."

RATIONALE FOR QUESTION:

RESPONSE:

Manitoba Hydro staff have been fully engaged with preparing PCOSS18 for this GRA and have not had the opportunity to undertake any further study of common costs, service drops or other such matters identified in Order 164/16.

Manitoba Hydro notes that while there were no expressed deadlines for these directives, it proposes to assess the further study of various costing topics after the completion of the current GRA. Manitoba Hydro will be in a better position to advise the PUB of its proposed approach at that time.

In the meantime, common costs continue to be functionalized on the basis of the labour allocator in PCOSS18, consistent with the interim direction provided in Order 164/16.

(ii) Variable hydraulic operating and maintenance costs associated with exports

(iii) The costs of the Affordable Energy Fund

1 (d) The costs of the Uniform Rate Adjustment shall not be deducted from export revenue;

1 (e) Export revenues shall not be credited to the Diesel class;

In preparing PCOSS18 Manitoba Hydro has complied with all of these directives. In its comments regarding the PCOSS14-Amended compliance filing, the Coalition noted that no information had been provided as to how the water rentals and variable hydraulic operating and maintenance costs associated with exports were determined. In its pre-filed evidence[149] Manitoba Hydro has provided an explanation of how these amounts were established for PCOSS18 and also provided further explanation in response to interrogatories[150].

In establishing the principles to be used in determining the COSS methodology the Board found the principle of cost causation is paramount[151]. This finding is reflected in Directive 1 (b) and the Board's observation that "the revenue from export sales is linked to the assets that give rise to export sales revenues, which are Generation and Transmission assets only, not Distribution assets"[152]. With this understanding as to the basis for the Board's directive regarding export revenue allocation there are two issues that arise.

First, as Manitoba Hydro has acknowledged[153], radial transmission lines are technically not integrated with the networked transmission system and therefore do not facilitate exports. As a result, since these assets do not give rise to (i.e., are not used for) exports, application of the Board's principles and rationale would suggest they should be excluded from the allocation of export revenues. The Board should refine its directive regarding the allocation of Export Revenue to exclude the roughly $7 M in costs associated with these assets.

[149] Tab 8, page 18
[150] GSS-GSM/MH I-8 and GAC/MH I-62
[151] Order 164/16, page 27
[152] Order 164/16, page 38
[153] COALITION/MH I-226 a)

Generation function[29], and Mr. Bowman is in agreement that in the case of Wuskwatim the W1, W2 and W3 lines could be considered GRTA, but cautions that it should not be applied to W73H, W74H and W76B[30]. In his presentation of September 8th, 2016 while arguing that Manitoba Hydro is making excessive use of GRTA, Mr. Bowman does note the treatment is appropriately applied to short generator outlets integral to the generators.

Manitoba Hydro has reviewed the transmission lines identified by parties and agrees that the following Non-Tarrifable Transmission facilities should be functionalized as Generation Outlet Transmission in future cost of service studies. Manitoba Hydro notes that the annualized cost of these lines is less than $2 million and will be un-impactful to overall cost of service results.

- Wuskwatim GS to Switchyard 230kV lines (W1,W2,W3)
- St. Leon wind farm 230kV (B78S)
- St. Joseph wind farm 230 kV line (J89L)
- Pointe du Bois-Rover 66kV lines (P3,P4)
- Slave Falls-Pointe du Bois 115kV lines (R1,R2)
- Pointe du Bois switching station

Mr. Chernick, however recommends that the use of the generation related transmission concept be expanded substantially, and identifies a lengthy list of transmission lines and substations that he believes should be functionalized as Generation.

Manitoba Hydro disagrees with Mr. Chernick's assessment of the role of these assets. All other transmission lines and switching stations listed on slides 21-23 of GAC's September 8th presentation are networked transmission assets eligible for inclusion in the OATT, and are appropriately functionalized as Transmission. These facilities are integral parts of the transmission grid 'spider web' that was referenced throughout the proceeding, and are used and useful to all transmission customers as described by Dr. Swatek (Transcript page 134):

> *"I would say it's a -- it's exactly how it sounds, that these assets are -- these transmission assets are simultaneously used and useful to serve all transmission customers. Transmission customers are served by a grid…. As Ms. Derksen pre -- presented this -- this morning, if you lose one (1) strand in that grid, the power -- the power is instantaneously redistributed over the grid to maintain continuity of supply. So every*

[29] Pre-filed Evidence of Mr. William Harper, June 10, 2016, pg. 69
[30] Pre-filed Evidence of Mr. Patrick Bowman, June 10, 2016, pg. 28

REFERENCE:

Tab 8

PREAMBLE TO IR (IF ANY):

QUESTION:

Please provide a list of AC transmission facilities included as generation outlet transmission and functionalized as generation in PCOSS18.

RATIONALE FOR QUESTION:

RESPONSE:

The AC transmission facilities functionalized as generation outlet transmission in PCOSS18 are:

- Northern Collector System
    - Limestone-Henday 230 kV line
    - Long Spruce-Radisson 230 kV line
    - Long Spruce-Henday 230 kV line
    - Kettle-Radisson 138 kV line
    - Limestone switching station
    - Long Spruce switching station
    - Kettle switching station
- Wuskwatim GS to switchyard 230 kV line
- St. Leon wind farm 230 kV line
- St. Joseph wind farm 230 kV line
- Pointe du Bois-Rover 66 kV line
- Slave Falls-Pointe du Bois 115 kV line
- Pointe du Bois switching station

MISO Fees

In PCOSS14 reflecting Order 164/16 filed with the PUB on February 21, 2017, Manitoba Hydro functionalized MISO costs to both Generation and Transmission.

As part of PCOSS18 and in consideration of PUB letter dated April 3, 2017, Manitoba Hydro has reviewed this treatment. IFF16 reflects a forecast of approximately $6 million of MISO-related costs. Of these total fees, approximately $5M are forecast to be incurred to administer Manitoba Hydro's Open Access Transmission Tariff requirements pursuant to a Coordination Agreement between Manitoba Hydro and MISO. These requirements include, but are not limited to, application of Manitoba Hydro transmission rates to Manitoba Hydro transmission customers for transmission service. It also includes collection and remittance of transmission revenues that are provided to Manitoba Hydro. These tariff services are thus unrelated to Manitoba Hydro's participation in the MISO market.

The PUB noted in its correspondence of April 3, 2017 that some of the MISO costs are not directly attributable to MISO and therefore may be functionalized as transmission. These Tariff Service costs are unrelated to Manitoba Hydro's participation in the MISO organized electricity markets and Manitoba Hydro views these costs as Transmission-related. As such, in PCOSS18, Manitoba Hydro has functionalized these costs as Transmission, specifically as part of the US Interconnection sub-function.

The remaining approximately $1M of MISO fees are charged to Manitoba Hydro on a cost recovery basis related to activities in the Day-Ahead, Real-Time and other external markets. As such, in PCOSS18, these charges associated with participating in the MISO markets continue to be functionalized as Generation.

For purposes of the determination of Manitoba Hydro's Open Access Transmission Tariff, obligations under the Coordination Agreement, and consistency with its Cost of Service Study, it is important to draw this functionalization distinction. However, it is noteworthy that both Generation and Transmission: US Interconnection are classified based on System Load Factor in the Cost of Service Study resulting in an identical allocation for both types of MISO charges.

In his Evidence, Mr. Bowman states that coal should be allocated to domestic customers only on account of legislation contained in Bill 15. While Manitoba Hydro agrees technically with Mr. Bowman's perspective, his recommendation adds unnecessary complexity particularly in view of the small magnitude of the dollars involved regarding Manitoba Hydro's investment in Coal Generation.

It would appear that Mr. Bowman may have reached that same conclusion during the workshops: *"But as I was discussing with the – the chairman earlier, one (1) of the natures of Hydro's system is that that role is not only different for every plant, it's different for every water flow for every plant. And by the time all is said and done, if ever there were a utility that you could take almost all of the plant and say, That functions as one (1) block, and I'm not going to try to pierce that veil and figure out what everything's doing, it's probably Manitoba Hydro because droughts look different than floods look different than average."* (Intervener Workshop, June 21, 2016, Transcript pages 148).

It was precisely this perspective that led Manitoba Hydro to the implementation of the pooled approach in PCOSS14-Amended. Manitoba Hydro believes that the pooled approach to generation assets is reasonable and pragmatically considers the balance between additional complexity and materiality related to Coal Generation. Manitoba Hydro is prepared on this basis, and within the context of its broader framework proposed for the treatment of exports, to include these costs in the generation pool to be allocated to both Domestic and Dependable export sales.

Similarly, in the absence of any demonstrated capacity benefits, Manitoba Hydro can conceptually support Mr. Bowman's recommendation to treat Wind resources as 100% Energy related. However, again given the added complexity introduced by creating an additional generation pool and the materiality of impact on COS results, Manitoba Hydro views it as more appropriate to continue to incorporate Wind resources into the overall Generation pool.

needed to meet capacity needs. GAC submits that the ability to meet peak demand is only a by-product of Manitoba Hydro building hydraulic generation that meets its dependable energy criterion.

MIPUG claims that Manitoba Hydro's proposed approach under-classifies costs as Demand, noting that Manitoba Hydro has confirmed that it considers both capacity and energy in generation planning. While MIPUG accepts Manitoba Hydro's Generation classification treatment for wind costs, MIPUG recommends that all other generating costs receive some peak capacity-related recognition.

MIPUG recommends an explicit Demand classification in the range of 21-23%, based on using either the system load factor or equivalent peaker methods. System load factor is the average demand divided by peak demand. A higher system load factor classifies more cost as Energy; conversely a lower load factor classifies more cost as Demand. The equivalent peaker method estimates the cost of an equivalent peaking generator, which is typically a single cycle combustion turbine, because it is the least expensive generator that can provide capacity (i.e. respond to peak demand). It then considers the cost of the alternative generator (e.g. hydroelectric, coal, etc.) and assumes the ratio of the alternative generator's cost to the equivalent peaker's cost is the same as the ratio of the energy to demand classification. According to MIPUG, Manitoba Hydro should consider using either the system load factor approach or the equivalent peaker methodology to determine the appropriate level of Demand classification for Generation costs.

Board Findings

The Board finds that Generation costs should be classified as both Energy and Demand, with the proportions determined by the system load factor method. The Generation costs to be classified on the system load factor basis include hydraulic generation, gas- and coal-fueled thermal generation, generation outlet transmission, and import purchases. The only exceptions to this approach are wind generation, water rentals, and variable hydraulic operation and maintenance costs, which should be classified as 100% Energy, as discussed further below.

The principal reason for classifying Generation costs as both Demand and Energy is that Manitoba Hydro plans for and invests in assets to satisfy both a winter peak capacity criterion and a dependable energy criterion. Meeting winter peak capacity is a critical requirement in Manitoba Hydro's operations and it drives certain investments. Peak capacity is not a by-product of meeting the dependable energy criterion. For example, hydroelectric facilities can have additional turbines installed in a given generating station that will increase capacity but not increase dependable energy. The additional capacity from these turbines, used in concert with other thermal and contracted resources, help satisfy the winter peak planning criterion. Classifying hydraulic generation, thermal generation, and import purchases as both Demand and Energy reflects the integrated nature of Manitoba Hydro's system and that these resources contribute both capacity and dependable energy and thus have cost causation traced to peak demand and energy consumption.

The Board finds that an explicit Demand classification is warranted. The Board rejects Manitoba Hydro's argument that the Weighted Energy allocator provides a sufficient and implicit Demand classification. Based on the importance of meeting peak demand in Manitoba Hydro's system, the Board finds that an explicit Demand classification should be employed.

The Board rejects the equivalent peaker methodology as too complex and open to continuing argument over the appropriate costs to be used in its calculation.

The Board directs the use of the system load factor because it is straight-forward and generally accepted in the industry. System load factor has a clear cost causation basis as it reflects the factors considered by resource planners when deciding the types of generation resources to add to the system.

The system load factor is to be based on multi-year historical domestic load data and updated for each COSS. Based on that load research data, in the next COSS and in the Compliance Filing from this Order, Manitoba Hydro should propose the appropriate number of years to consider in the calculation of the system load factor. Using multiple years of data will improve the year-over-year stability of the system load factor.

The system load factor methodology used by Manitoba Hydro prior to 2006 is not to be used. This previous methodology grouped the Generation and Transmission costs together, classified them by system load factor, but then considered the Transmission costs to be 100% Demand.

Wind generation, water rentals, and variable hydraulic operation and maintenance costs should be classified as 100% Energy. If Manitoba Hydro incurs other costs in the future, such as for solar generation that are exclusively Energy-related and have no Demand component, then such costs should likewise be classified as 100% Energy. Wind generation is subject to prevailing wind conditions and thus Manitoba Hydro cannot count on wind generation at any specific point in time. For example, Manitoba Hydro cannot call on wind generation to meet its winter peak demand. Since wind generation does not contribute to the winter peak capacity, it should be classified 100% as Energy. Water rentals are paid to the Province for every kWh of hydraulic generation and thus vary directly with energy produced, hence an Energy classification. Similarly, variable hydraulic operation and maintenance costs are costs that are incurred for each kWh of hydraulic energy produced.

Generation Allocation

Manitoba Hydro's Position

Manitoba Hydro's position is that a Weighted Energy allocator should be used to allocate all Generation costs. The Weighted Energy allocator weights the energy by the relative value of exports during twelve separate time periods. In other words, classes that consume more energy will be allocated a greater share of costs, and if a greater

4 NEED FOR NEW RESOURCES TO MEET EXISTING OBLIGATIONS

The need for new resources to meet the expected load requirements is assessed using supply assumptions which include the base supply of power resources including committed resources, and the Manitoba base load forecast net of demand side management (DSM) and export sales requirements. Using the planning criteria, the supply-demand surplus, or deficit is determined for each year for 35 years into the future. The year in which significant persistent deficits begin for either dependable energy or peak capacity is the year that new resources are required.

Table 1 shows the changes in the dates that new resources are needed for both dependable energy and capacity compared to the 2016 Resource Planning Assumptions & Analysis. The variation in the date new resources are needed is due to changes in the load forecast, DSM, and base resource assumptions including allowable import quantities, wind generation, and existing system capabilities.

Subsequent to the completion of the 2016 Resource Planning Assumptions & Analysis, there have been changes in the supply and demand balance which have resulted in Manitoba Hydro updating the supply and demand balance information for the 2016 Integrated Financial Forecast. The updated supply and demand balance information includes a 21 month delay in the in-service date for the Keeyask Generating Station, and the adjustments to the 2016 Electric Load Forecast, and is summarized in Table 1 below.

For the 2017 planning assumptions, the need for new resources is driven by sustained dependable energy shortfall beginning in 2039/40. Resources are required to meet sustained capacity deficits beginning in 2041/42

Table 1: Changes to Supply-Demand Balances

Changes to Dependable Energy (GWh)								
Fiscal Year	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45
System Surplus (Deficit) 2016, No New Resources	423	(157)	(728)	(1,324)	(1,919)	(2,503)	(3,098)	(3,695)
System Surplus (Deficit) 2016 IFF, No New Resources	1,454	961	477	(33)	(540)	(1,038)	(1,546)	(2,055)
System Surplus (Deficit) 2017, No New Resources	783	344	(485)	(470)	(821)	(1,253)	(1,696)	(2,141)

Changes to Winter Peak Capacity (MWs)								
Fiscal Year	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45
System Surplus (Deficit) 2016, No New Resources	133	5	(122)	(141)	(271)	(401)	(530)	(661)
System Surplus (Deficit) 2016 IFF, No New Resources	434	328	222	225	117	8	(100)	(208)
System Surplus (Deficit) 2017, No New Resources	254	157	32	43	(56)	(155)	(254)	(355)

 24

APPENDIX A DEPENDABLE SUPPLY & DEMAND

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
2017 RPAA, 2017 50th Percentile Load Forecast, with 2016 DSM Forecast (2017 update)
No New Resources

Fiscal Year		2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2035/36
Power Resources																			
New Power Resources																			
New Hydro																			
Conawapa																			
Notigi																			
Manasan																			
Early Morning																			
First Rapids																			
1 **Total New Hydro**																			
New Thermal																			
SCGT																			
CCGT																			
2 **Total New Thermal**																			
3 **Total New Power Resources**	1+2																		
Base Supply Power Resources																			
Existing and Committed Hydro		5 105	5 110	5 289	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727
Existing Thermal																			
Brandon Coal/ Unit 5																			
Selkirk Gas		33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
Brandon Units 6-7 SCGT		278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278
Contracted Imports		688	605	605	605	605	605	220	220	220	220	220							
Proposed Imports													220	220	220	220	220	220	220
Additional Market Resources																			
Existing Wind		52	52	52	52	52	52	52	32	32	32	32	32	32	32	32	32	32	28
Generation Outages Over System Peak		- 15						- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15
Bipole III Reduced Losses		90	90	90	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
4 **Total Base Supply Power Resources**		**6 230**	**6 167**	**6 346**	**6 775**	**6 775**	**6 775**	**6 375**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 351**
5 **Total Power Resources**	3+4	**6 230**	**6 167**	**6 346**	**6 775**	**6 775**	**6 775**	**6 375**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 355**	**6 351**
Peak Demand																			
2017 Base Load Forecast		4 794	4 798	4 873	4 894	4 927	4 987	5 059	5 139	5 220	5 299	5 381	5 465	5 552	5 643	5 734	5 826	5 921	6 021
Less: 2016 DSM Forecast (2017 update)		- 229	- 314	- 396	- 441	- 478	- 512	- 547	- 582	- 617	- 652	- 688	- 722	- 728	- 733	- 739	- 744	- 749	- 754
6 **Manitoba Net Load**		4 565	4 484	4 477	4 453	4 449	4 475	4 513	4 557	4 603	4 646	4 693	4 743	4 824	4 910	4 995	5 083	5 172	5 267
Contracted Exports		727	945	1 018	990	990	990	495	495	385	385	385	385	385	385	385	385	110	110
Proposed Exports																			
7 **Total Exports**		727	945	1 018	990	990	990	495	495	385	385	385	385	385	385	385	385	110	110
8 **Total Peak Demand**	6+7	**5 292**	**5 429**	**5 494**	**5 443**	**5 439**	**5 465**	**5 008**	**5 052**	**4 988**	**5 031**	**5 078**	**5 128**	**5 209**	**5 295**	**5 380**	**5 468**	**5 282**	**5 377**
9 Reserves		537	531	531	529	528	532	535	540	545	550	555	561	571	581	592	602	610	621
10 **System Surplus**	5-8-9	**401**	**207**	**321**	**802**	**807**	**778**	**832**	**762**	**822**	**773**	**721**	**665**	**574**	**479**	**383**	**285**	**463**	**352**

System Firm Winter Peak Demand and Capacity Resources (MW) @ generation
2017 RPAA, 2017 50th Percentile Load Forecast, with 2016 DSM Forecast (2017 update)
No New Resources

Fiscal Year		2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48	2048/49	2049/50	2050/51	2051/52	2052/53
Power Resources																		
New Power Resources																		
New Hydro																		
Conawapa																		
Notigi																		
Manasan																		
Early Morning																		
First Rapids																		
1 **Total New Hydro**																		
New Thermal																		
SCGT																		
CCGT																		
2 **Total New Thermal**																		
3 **Total New Power Resources**	1+2																	
Base Supply Power Resources																		
Existing and Committed Hydro		5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727	5 727
Existing Thermal																		
Brandon Coal/ Unit 5																		
Selkirk Gas		33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
Brandon Units 6-7 SCGT		278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278	278
Contracted Imports																		
Proposed Imports		220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
Additional Market Resources																		
Existing Wind		28	28	28														
Generation Outages Over System Peak		- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15	- 15
Bipole III Reduced Losses		80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
4 **Total Base Supply Power Resources**		**6 351**	**6 351**	**6 351**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**
5 **Total Power Resources**	3+4	**6 351**	**6 351**	**6 351**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**	**6 323**
Peak Demand																		
2017 Base Load Forecast		6 021	6 113	6 205	6 297	6 389	6 481	6 573	6 664	6 756	6 848	6 940	7 032	7 124	7 216	7 308	7 399	7 491
Less: 2016 DSM Forecast (2017 update)		- 754	- 759	- 764	- 769	- 771	- 775	- 778	- 781	- 783	- 786	- 784	- 783	- 782	- 781	- 781	- 780	- 780
6 **Manitoba Net Load**		5 267	5 354	5 441	5 528	5 617	5 706	5 795	5 883	5 973	6 062	6 156	6 249	6 342	6 435	6 527	6 619	6 711
Contracted Exports		110	110	110	110													
Proposed Exports																		
7 **Total Exports**		110	110	110	110													
8 **Total Peak Demand**	6+7	**5 377**	**5 464**	**5 551**	**5 638**	**5 617**	**5 706**	**5 795**	**5 883**	**5 973**	**6 062**	**6 156**	**6 249**	**6 342**	**6 435**	**6 527**	**6 619**	**6 711**
9 Reserves		621	632	642	653	662	673	683	694	705	715	727	738	749	760	771	782	793
10 **System Surplus**	5-8-9	**352**	**254**	**157**	**32**	**43**	**- 56**	**- 155**	**- 254**	**- 355**	**- 455**	**- 559**	**- 664**	**- 768**	**- 872**	**- 975**	**-1 079**	**-1 182**

26

System Firm Summer Peak Demand and Capacity Resources (MW) @ generation
2017 RPAA, 2017 50th Percentile Load Forecast, with 2016 DSM Forecast (2017 update)
No New Resources

#	Fiscal Year		2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36	2035/36
	Power Resources																			
	New Power Resources																			
	New Hydro																			
	Conawapa																			
	Notigi																			
	Manasan																			
	Early Morning																			
	First Rapids																			
1	**Total New Hydro**																			
	New Thermal																			
	SCGT																			
	CCGT																			
2	**Total New Thermal**																			
3	**Total New Power Resources**	1+2																		
	Base Supply Power Resources																			
	Existing and Committed Hydro		5 140	5 144	5 135	5 594	5 760	5 760	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759
	Existing Thermal																			
	Brandon Coal/ Unit 5																			
	Selkirk Gas		33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
	Brandon Units 6-7 SCGT		228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
	Contracted Imports																			
	Proposed Imports																			
	Additional Market Resources																			
	Existing Wind		40	40	40	40	40	40	40	25	25	25	25	25	25	25	25	25	25	25
	Generation Outages Over Summer Peak								- 15	- 133	- 133	- 133	- 133	- 115	- 115	- 115	- 115	- 115	- 115	- 115
	Bipole III Reduced Losses		90	90	90	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
4	**Total Base Supply Power Resources**		**5 531**	**5 535**	**5 526**	**5 975**	**6 141**	**6 141**	**6 126**	**5 992**	**5 992**	**5 992**	**5 992**	**6 010**	**6 010**	**6 010**	**6 010**	**6 010**	**6 010**	**6 010**
5	**Total Power Resources**	3+4	**5 531**	**5 535**	**5 526**	**5 975**	**6 141**	**6 141**	**6 126**	**5 992**	**5 992**	**5 992**	**5 992**	**6 010**	**6 010**	**6 010**	**6 010**	**6 010**	**6 010**	**6 010**
	Peak Demand																			
	2017 Base Load Forecast		3 425	3 429	3 499	3 516	3 538	3 583	3 636	3 693	3 751	3 809	3 868	3 929	3 992	4 057	4 122	4 188	4 256	4 327
	Less: 2016 DSM Forecast (updated)		- 127	- 164	- 198	- 227	- 257	- 286	- 316	- 346	- 378	- 413	- 449	- 485	- 489	- 494	- 498	- 502	- 506	- 510
6	**Manitoba Net Load**		3 298	3 265	3 301	3 289	3 281	3 298	3 320	3 348	3 373	3 396	3 419	3 444	3 503	3 563	3 624	3 686	3 750	3 817
	Contracted Exports		1 469	1 605	1 678	1 650	1 650	1 650	715	715	605	605	605	385	385	385	385	385	110	110
	Proposed Exports													220	220	220	220	220	220	220
7	**Total Exports**		1 469	1 605	1 678	1 650	1 650	1 650	715	715	605	605	605	605	605	605	605	605	330	330
8	**Total Peak Demand**	6+7	**4 767**	**4 870**	**4 979**	**4 939**	**4 931**	**4 948**	**4 035**	**4 063**	**3 978**	**4 001**	**4 024**	**4 049**	**4 108**	**4 168**	**4 229**	**4 291**	**4 080**	**4 147**
9	Reserves		401	398	404	403	402	404	397	400	402	405	407	410	417	425	432	439	444	452
10	**System Surplus**	5-8-9	**363**	**267**	**143**	**633**	**808**	**789**	**1 694**	**1 529**	**1 612**	**1 587**	**1 561**	**1 550**	**1 485**	**1 417**	**1 349**	**1 279**	**1 486**	**1 411**

System Firm Summer Peak Demand and Capacity Resources (MW) @ generation
2017 RPAA, 2017 50th Percentile Load Forecast, with 2016 DSM Forecast (2017 update)
No New Resources

Fiscal Year		2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48	2048/49	2049/50	2050/51	2051/52	2052/53
Power Resources																		
New Power Resources																		
New Hydro																		
Conawapa																		
Notigi																		
Manasan																		
Early Morning																		
First Rapids																		
1 **Total New Hydro**																		
New Thermal																		
SCGT																		
CCGT																		
2 **Total New Thermal**																		
3 **Total New Power Resources**	1+2																	
Base Supply Power Resources																		
Existing and Committed Hydro		5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759	5 759
Existing Thermal																		
Brandon Coal/ Unit 5																		
Selkirk Gas		33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
Brandon Units 6-7 SCGT		228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228	228
Contracted Imports																		
Proposed Imports																		
Additional Market Resources																		
Existing Wind		25	22	22														
Generation Outages Over System Peak		- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115	- 115
Bipole III Reduced Losses		80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80	80
4 **Total Base Supply Power Resources**		**6 010**	**6 007**	**6 007**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**
5 **Total Power Resources**	3+4	**6 010**	**6 007**	**6 007**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**	**5 985**
Peak Demand																		
2017 Base Load Forecast		4 327	4 394	4 460	4 526	4 592	4 658	4 725	4 791	4 857	4 923	4 989	5 056	5 122	5 188	5 254	5 320	5 387
Less: 2016 DSM Forecast (updated)		- 510	- 513	- 517	- 521	- 523	- 526	- 529	- 532	- 534	- 537	- 535	- 535	- 534	- 533	- 533	- 533	- 533
6 **Manitoba Net Load**		3 817	3 880	3 942	4 005	4 069	4 132	4 195	4 259	4 323	4 387	4 454	4 521	4 588	4 655	4 721	4 788	4 854
Contracted Exports		110	110	110	110													
Proposed Exports		220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220	220
7 **Total Exports**		330	330	330	330	220	220	220	220	220	220	220	220	220	220	220	220	220
8 **Total Peak Demand**	6+7	**4 147**	**4 210**	**4 272**	**4 335**	**4 289**	**4 352**	**4 415**	**4 479**	**4 543**	**4 607**	**4 674**	**4 741**	**4 808**	**4 875**	**4 941**	**5 008**	**5 074**
9 Reserves		452	460	467	475	481	489	496	504	512	519	527	535	543	551	559	567	575
10 **System Surplus**	5-8-9	**1 411**	**1 337**	**1 267**	**1 176**	**1 215**	**1 144**	**1 073**	**1 002**	**931**	**859**	**784**	**709**	**634**	**559**	**485**	**410**	**336**

28

System Firm Energy Demand and Dependable Resources (GWh) @ generation
2017 RPAA, 2017 50th Percentile Load Forecast, with 2016 DSM Forecast (2017 update)
No New Resources

Fiscal Year		2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35	2035/36
Power Resources																		
New Power Resources																		
New Hydro																		
Conawapa																		
Notigi																		
Manasan																		
Early Morning																		
First Rapids																		
1 **Total New Hydro**																		
New Thermal																		
SCGT																		
CCGT																		
2 **Total New Thermal**																		
3 New Wind																		
4 **Total New Power Resources**	1+2+3																	
Base Supply Power Resources																		
Existing and Committed Hydro		21 826	21 717	23 005	24 625	24 625	24 615	24 605	24 605	24 595	24 585	24 585	24 575	24 575	24 565	24 555	24 555	24 545
Existing Thermal																		
Brandon Coal/ Unit 5																		
Selkirk Gas		899	899	899	899	899	899	899	899	899	899	899	899	899	899	899	899	899
Brandon Units 6-7 SCGT		2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343
Contracted Imports		2 810	3 502	3 688	3 688	3 688	3 688	2 321	2 050	2 050	2 050	2 050	1 268	1 113	1 113	1 113	1 113	186
Proposed Imports													781	936	936	936	936	936
Hydro Adjustment		903	844	844	844	844	844	406	307	307	307	307	307	307	307	307	307	307
Market Purchases		258	1 686	1 500	1 500	1 500	1 500	2 202	2 441	2 053	1 996	2 023	1 889	1 932	1 978	2 023	2 070	2 009
Existing Wind		781	781	781	781	781	781	781	545	483	483	483	483	483	483	483	483	483
Bipole III Reduced Losses		101	101	101	177	177	177	177	177	177	177	177	177	177	177	177	177	177
5 **Total Base Supply Power Resources**		**29 920**	**31 873**	**33 162**	**34 857**	**34 857**	**34 847**	**33 733**	**33 367**	**32 906**	**32 839**	**32 866**	**32 722**	**32 765**	**32 801**	**32 836**	**32 883**	**31 884**
6 **Total Power Resources**	4+5	**29 920**	**31 873**	**33 162**	**34 857**	**34 857**	**34 847**	**33 733**	**33 367**	**32 906**	**32 839**	**32 866**	**32 722**	**32 765**	**32 801**	**32 836**	**32 883**	**31 884**
Manitoba Domestic Load																		
2017 Base Load Forecast		26 220	26 238	26 766	26 877	27 055	27 389	27 780	28 208	28 641	29 068	29 510	29 962	30 428	30 914	31 399	31 895	32 398
Construction Power adjustment																		
Less: 2016 DSM Forecast (updated)		-1 052	-1 368	-1 657	-1 837	-2 006	-2 163	-2 325	-2 482	-2 647	-2 818	-2 993	-3 163	-3 195	-3 227	-3 257	-3 285	-3 311
7 **Manitoba Net Load**		**25 167**	**24 870**	**25 109**	**25 040**	**25 049**	**25 226**	**25 455**	**25 727**	**25 994**	**26 250**	**26 518**	**26 799**	**27 234**	**27 687**	**28 142**	**28 610**	**29 087**
Contracted Exports		3 410	4 519	5 168	5 054	5 027	5 027	2 744	2 600	2 185	2 102	2 102	1 940	1 940	1 940	1 940	1 940	904
Proposed Exports													162	162	162	162	162	162
Less: Adverse Water		- 370	- 370	- 489	- 513	- 513	- 513	- 85										
8 **Total Net Exports**		**3 040**	**4 148**	**4 679**	**4 541**	**4 514**	**4 514**	**2 659**	**2 600**	**2 185**	**2 102**	**2 102**	**2 102**	**2 102**	**2 102**	**2 102**	**2 102**	**1 066**
9 **Total Energy Demand**	7+8	**28 207**	**29 019**	**29 788**	**29 581**	**29 563**	**29 741**	**28 114**	**28 326**	**28 180**	**28 352**	**28 620**	**28 901**	**29 336**	**29 789**	**30 244**	**30 713**	**30 153**
10 **System Surplus**	6-9	**1 713**	**2 855**	**3 374**	**5 276**	**5 294**	**5 106**	**5 619**	**5 041**	**4 727**	**4 487**	**4 246**	**3 820**	**3 430**	**3 011**	**2 592**	**2 170**	**1 732**

29

System Firm Energy Demand and Dependable Resources (GWh) @ generation
2017 RPAA, 2017 50th Percentile Load Forecast, with 2016 DSM Forecast (2017 update)
No New Resources

Fiscal Year		2036/37	2037/38	2038/39	2039/40	2040/41	2041/42	2042/43	2043/44	2044/45	2045/46	2046/47	2047/48	2048/49	2049/50	2050/51	2051/52	2052/53
Power Resources																		
New Power Resources																		
New Hydro																		
Conawapa																		
Notigi																		
Manasan																		
Early Morning																		
First Rapids																		
1 **Total New Hydro**																		
New Thermal																		
SCGT																		
CCGT																		
2 **Total New Thermal**																		
3 New Wind																		
4 **Total New Power Resources**	1+2+3																	
Base Supply Power Resources																		
Existing and Committed Hydro		24 535	24 535	24 525	24 525	24 515	24 505	24 505	24 495	24 485	24 485	24 475	24 465	24 465	24 455	24 455	24 445	24 435
Existing Thermal																		
Brandon Coal/ Unit 5																		
Selkirk Gas		899	899	899	899	899	899	899	899	899	899	899	899	899	899	899	899	899
Brandon Units 6-7 SCGT		2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343	2 343
Contracted Imports																		
Proposed Imports		936	936	936	936	936	936	936	936	936	936	936	936	936	936	936	936	936
Hydro Adjustment		307	307	307	307	307	307	307	307	307	307	307	307	307	307	307	307	307
Market Purchases		2 038	2 084	2 131	2 177	2 226	2 274	2 322	2 370	2 418	2 466	2 516	2 566	2 615	2 664	2 714	2 763	2 812
Existing Wind		467	422	410														
Bipole III Reduced Losses		177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177	177
5 **Total Base Supply Power Resources**		**31 702**	**31 703**	**31 728**	**31 364**	**31 403**	**31 441**	**31 489**	**31 527**	**31 565**	**31 613**	**31 653**	**31 692**	**31 742**	**31 781**	**31 831**	**31 870**	**31 909**
6 **Total Power Resources**	4+5	**31 702**	**31 703**	**31 728**	**31 364**	**31 403**	**31 441**	**31 489**	**31 527**	**31 565**	**31 613**	**31 653**	**31 692**	**31 742**	**31 781**	**31 831**	**31 870**	**31 909**
Manitoba Domestic Load																		
2017 Base Load Forecast		32 930	33 426	33 916	34 408	34 900	35 391	35 883	36 374	36 866	37 358	37 849	38 341	38 832	39 324	39 816	40 307	40 799
Construction Power adjustment																		
Less: 2016 DSM Forecast (updated)		-3 337	-3 364	-3 390	-3 416	-3 426	-3 437	-3 448	-3 459	-3 467	-3 476	-3 471	-3 468	-3 465	-3 463	-3 462	-3 461	-3 461
7 **Manitoba Net Load**		**29 593**	**30 062**	**30 526**	**30 992**	**31 474**	**31 954**	**32 435**	**32 915**	**33 399**	**33 882**	**34 378**	**34 873**	**35 367**	**35 861**	**36 353**	**36 846**	**37 338**
Contracted Exports		696	696	696	696	237	145	145	145	145	145	145	145	145	145	145	145	145
Proposed Exports		162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162	162
Less: Adverse Water																		
8 **Total Net Exports**		**858**	**858**	**858**	**858**	**399**	**307**	**307**	**307**	**307**	**307**	**307**	**307**	**307**	**307**	**307**	**307**	**307**
9 **Total Energy Demand**	7+8	**30 451**	**30 920**	**31 384**	**31 850**	**31 873**	**32 261**	**32 742**	**33 222**	**33 706**	**34 189**	**34 685**	**35 180**	**35 674**	**36 168**	**36 660**	**37 153**	**37 645**
10 **System Surplus**	6-9	**1 251**	**783**	**344**	**- 485**	**- 470**	**- 821**	**-1 253**	**-1 696**	**-2 141**	**-2 575**	**-3 032**	**-3 487**	**-3 932**	**-4 387**	**-4 830**	**-5 283**	**-5 736**

Figure 8.3 Calculation of Average System Load Factor

Fiscal Year	Load Factor %
2008/09	61.8%
2009/10	60.8%
2010/11	63.6%
2011/12	61.7%
2012/13	62.0%
2013/14	61.7%
2014/15	61.8%
2015/16	62.9%
Average	62.0%

As noted in Tab 7 (Appendix 7.3) of the Corporation's Application, Manitoba Hydro has reviewed its experience with wind generation. Based on operational experience, it was concluded that wind generation does provide both winter peak capacity and summer peak capacity capability. For purposes of Cost of Service, PCOSS18 continues to classify wind generation as 100% Energy consistent with Order 164/16. Manitoba Hydro is of the view that it is reasonable to continue with current methodology considering the limited capacity value, that operationally its wind power purchases under contract are energy based, and considering the negligible impact to RCC. This also appears to be consistent with the spirit of the overall COS methodology approach flowing from Order 164/16 which takes a pooled approach to generation resources and considers these costs jointly.

The classification of the remaining functions in PCOSS18 is consistent with that directed in Order 164/16:

- Transmission has been classified as 100% Demand, with the exception of the US Interconnection which is classified using System Load Factor, consistent with the Generation function
- Subtransmission is classified as 100% Demand
- Distribution Service costs are classified as 100% customer-related;

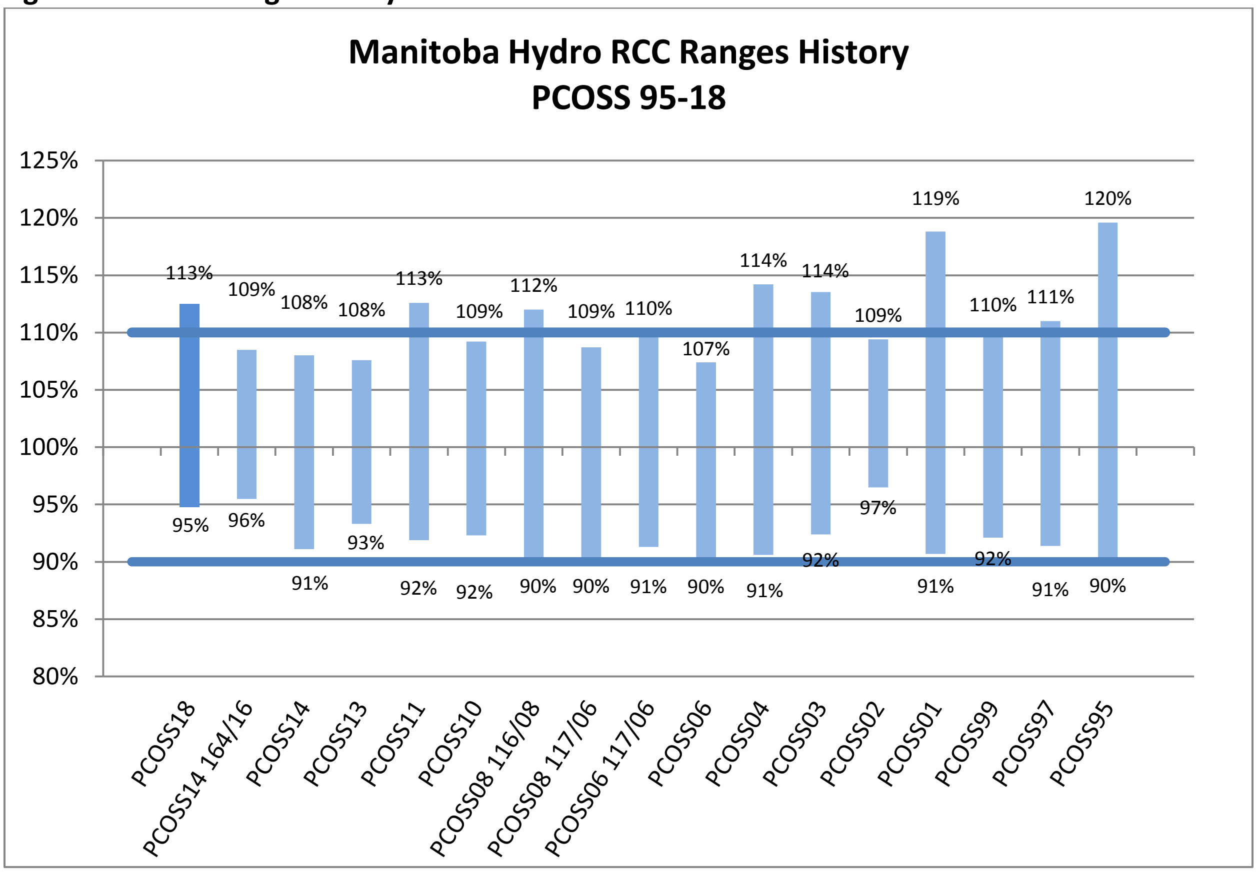
107

This simplified estimated marginal cost by class provides the directional degree to which class RCCs are significantly below or above unity and is a reasonable basis by which class RCCs flowing from PCOSS18 may be additionally evaluated. The theoretical ideal of rates based on marginal cost would suggest that rates should not fall below marginal cost but in fact do for most classes. However, in Manitoba Hydro's view, the alignment of rates and rate relationships with the pattern of marginal cost is important to support its economic efficiency rate objective. And, Manitoba Hydro's ZOR should be reasonably broad enough to allow flexibility in ratemaking to consider the degree of variability in marginal cost that exists between customer classes.

8.5.2 Historically Accepted Practice

It is noteworthy to review and consider historical precedence regarding RCC range around unity flowing from the Corporation's Cost of Service Studies over the past 20 years. The chart below provides RCCs experienced over this period of time. It is worth noting that during this time period there were a series of cost of service methodology changes, additional policy considerations, annual export revenues which experienced significant increases followed by decreases, and relatively stable levels of plant investment.

Figure 8.15 RCC Range History



A Zone of Reasonableness is also generally a matter of judgment in that there is no generally accepted quantitative methodology for determining an appropriate band. However, with consideration of nearly 20 years of cost of service results, a Zone of Reasonableness of 90% to 110% or even broader has been implicitly accepted as reasonable for purposes of rate setting in this jurisdiction. On this basis, continued across-the-board rates changes are reasonable.

8.6 <u>2014/15 ELECTRIC LOAD RESEARCH RESULTS</u>

This section presents a summary of results by domestic customer class from the Corporation's Load Research program. These results are used to develop the peak responsibility tables in the Corporation's Cost of Service Study. The Load Research results pertain to the fiscal year ending March 31, 2015. The Load Research results are an integral part of the Cost of Service Study which applies forecast energies to the results to develop demand allocators.

The following Load Research report and tables are provided as attachments:

Appendix 8.3 - Load Research Report: 2014/15 Load Research report including results at generation and common bus, graphical class Load profiles, monthly class peaks, streetlight "on-hours", 12 period TOU and class typical day plots during summer and winter periods. Also a description of the Load Research program, sample design, statistics, top-50 peak method and a glossary of terms are included.

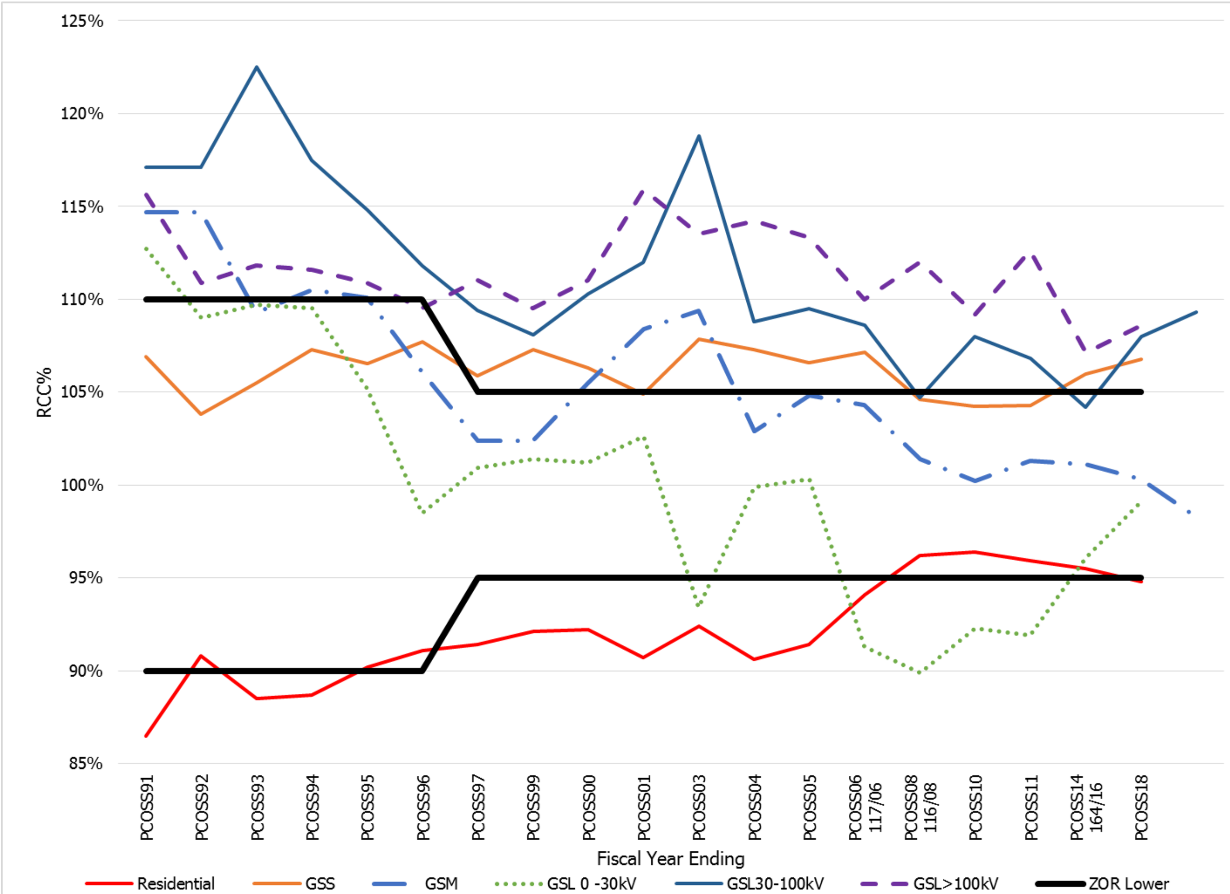
Appendix 8.4 - Load Research Results at Generation: 2014/15 Load Research results corresponding to the top 50 winter peaks at generation showing: number of customers, billed energy, average energy, estimated and actual coincident and non-coincident peaks by class and relative accuracy of peak load estimates.

Appendix 8.5 - Load Research Results at Common Bus: 2014/15 Load Research corresponding to the top 50 summer peaks at generation showing: number of customers, billed energy, average energy, estimated and actual coincident and non-coincident peaks by class and relative accuracy of peak load estimates.

Appendix 8.6 - Load Research Class Load Profiles: 2014/15 Load Research hourly load profiles for domestic customer classes.

Appendix 8.7 - Load Research 12 Period 8 Year TOU Report: Load Research table of 12 period TOU energies for domestic customer classes showing 8 years of results ending March 31, 2015.

Figure 7-2: Revenue Cost Coverage Ratios by Customer Class[233]



Note that the results in Figure 7-2 are as reported in the respective PCOSS – as noted above this has a dampening effect on the true percentage by which each class faces rates over or under measured costs, due to the arithmetic Hydro applies to export revenues.

In this current GRA, Hydro suggests that a new widening of the zone of reasonableness to 90%-110% may be reasonable in light of historical precedence and continuity, ratemaking and policy objectives, the degree of variability in cost allocation methodologies and cost definition and the changing cost structure in future rate applications due to the significant infrastructure investment underway for Manitoba Hydro[234]. Such a revision would not be advisable. The basic premise for utility ratemaking is to recover rates that reflect costs – overall rates to reflect the costs of the utility, and between the classes, rates that reflect the costs to serve that class. Some jurisdictions, such as Newfoundland and Labrador, strictly target 100.00% for

[233] 1991-1994 and 1996 RCC ratios from MIPUG/MH/CR-2(b), Manitoba Hydro 1996/97 GRA. RCC ratios for 1995, 1997, 1999, 2001-2004 and 2006-2018 from Appendix 8.1, page 38, Manitoba Hydro 2017/18 & 2018/19 GRA. 2000 RCC ratios from MIPUG/MH I-30(a), Manitoba Hydro 2015/16 GRA. 2005 RCC ratios from MIPUG/MH I-21(f), Manitoba Hydro 2004 GRA.
[234] PUB/MH I-137a

setting industrial rates, which can, at times, undermine other rate redesign objectives such as rate stability. Outside of such consideration, there is no reasonable basis to ignore a valid, regulatory-approved COS result in setting rates by class.

For the GSL >100kV customers to even reach a 105% RCC a substantial one-time rate decreases would be required of approximately 0.26 cents/kW.h (GSL >100 kV costs at 3.57 cents/kW.h, at 105% this yields 3.75 cents/kW.h – compare to current rates at 4.01 cents/kW.h). To large power users, continuing to pay energy rates at a level this much higher than costs has implications to competitiveness and economics.

However, among the considerations that should be brought to bear on such rate adjustments is long-term stability. Hydro notes that Bipole III is coming into service, but is not yet included in the PCOSS. While a PCOSS fully incorporating Bipole III has not yet been prepared, it is clear that this asset will drive bulk power costs in the COS study notably higher (even when Bipole III costs are offset by the Bipole III revenue deferral amortization). This does not limit the Board from providing improvements to the RCC ratio by awarding lower than average rate increases to industrials of, for example, 1-2% below the average rate increase awarded (similar to the Board's decision in Order 7/2003), but does suggest caution in regards to large moves such as calculated above (i.e., a reduction of the full 0.26 cents/kW.h at one time is not advised).

7.2.1 Time of Use (TOU) Rates

Hydro had previously applied for Time of Use ("TOU") rates in the 2015/16 GRA; however the Board determined it would be addressed in the Cost of Service review, and these rates were ultimately not reviewed at that GRA[235]. In the Cost of Service review rate-related matters, including rate rebalancing, time-of-use rates and conservation rates were excluded from the scope of the Cost of Service methodology review to the next GRA[236] (i.e. this proceeding).

Hydro did not submit a TOU rate proposal in this GRA. Hydro is not proposing to implement TOU rates in this application as Hydro has generally only considered TOU rates as a mandatory change to the industrial rate schedule affecting all customers, and as a result under Hydro's concept of a TOU rate there would be 'winners and losers'. Specifically, some customers who would be charged this rate, such as high load factor customers who are unable to shift production to off-peak periods, would be burdened, essentially funding any bill reductions to the customers that can make use of off-peak time periods to reduce costs.[237] This is a difficult challenge to the implementation of Hydro's concept at the best of times, but particularly so when facing a 7.9% rate increase proposal.

[235] Order 73/15, page 89 of 90
[236] Order 26/16, page 16
[237] Tab 9, page 4

REFERENCE:

Tab 8, page 27, Figure 8.12; page 2, lines 15-8; page 33, lines 6-8

PREAMBLE TO IR (IF ANY):

Figure 8.12 on page 27 of Tab 8 of the submitted general rate application provides the revenue cost coverage percentages (RCC %) that result in PCOSS18. Manitoba Hydro indicates on page 2 of Tab 8, lines 15-18, that the accepted standard for rate setting is to establish the RCC % to within a target Zone of Reasonableness range of 95 percent to 105. Further, Manitoba Hydro states on page 33 of Tab 8, lines 6-8, that "with consideration of nearly 20 years of cost of service results, a Zone of Reasonableness of 90% to 110% or even broader has been implicitly accepted as reasonable for purposes of rate setting in this jurisdiction."

QUESTION:

a) In regards to the statements noted above:
   i. What is Manitoba Hydro's recommended zone of reasonableness?
   ii. How has a 90% to 110% or even broader range been implicitly accepted?
   iii. Please provide references to any documents Manitoba Hydro relied upon to support these statements other than Figure 8.15, if any.
b) In regards to Figure 8.12, please provide the estimated annual outcomes under the following scenarios:
   i. For all rates classes, what would be the estimated annual change in class revenue required to achieve cost parity for each rate class within 1, 5, and 10 years.
   ii. For all rate classes, what would be the annual change in class revenue required to move all rate classes to within the Zone of Reasonableness within 1, 5, and 10 years.

RATIONALE FOR QUESTION:

RESPONSE:

a) In order to determine the appropriate range to use for a Zone of Reasonableness (ZOR) it is important to consider how both the class Revenue Cost Coverage (RCC) ratios, as well as the ZOR itself, may be used by the regulator in the process of determining just and reasonable rates.

The PUB is charged with the responsibility of approving rates for the provision of power that are just and reasonable and that are neither unduly discriminatory nor preferential. Typically, it is considered important to set rates that produce a level of revenue that reasonably compares to the cost of serving that class of customers. Rates that are cost-based are generally considered to be just and reasonable.

A Zone of Reasonableness is a measure of accepted bandwidth in which to evaluate class RCCs and determine whether class revenues are sufficient, or whether consideration should be given to adjusting revenues between rate classes.

In addition to the cost to serve, the PUB has broad discretion to consider any compelling policy issues or other factors that it regards as relevant to rate setting. While the cost to serve may be a key consideration, the PUB is clearly able to take other factors into account in approving rates it deems just and reasonable. In Order 164/16 the PUB acknowledged that "In setting domestic electricity rates, the Board has discretion as to what, if any, use is made of the COSS." (page 16).

In Order 164/16, the PUB also provided clear direction on the methodology to be used in the preparation of future cost of service studies, as well as its views on the role that cost causation should play in these studies. The PUB determined that cost causation should be the primary objective of a cost of service study and that other ratemaking principles should be considered at the rate setting stage of the process after the cost of service results are known[1].

[1] Order 164/16, page 27 – Board Findings "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

It is also important to consider what an RCC ratio measures for each customer class, namely costs and revenues. For the past number of years, the PUB has approved an application of revenue increases on an across-the-board basis, whereby revenues for each rate class are increased by the same percentage. However, with the introduction of significant changes in Cost of Service methodology as a result of Order164/16, the net costs allocated to each customer class have abruptly changed, as shown in Figure 8.12 on page 27 of Tab 8. It is necessary to consider the magnitude of these changes and then allow for sufficient flexibility when applying RCC outcomes, otherwise these cost changes may result in similarly abrupt changes to class rates.

Manitoba Hydro's previous COSS methodology incorporated a number of features that addressed ratemaking objectives in the COSS itself. The weighted Energy allocator, the inclusion of the Uniform Rate Adjustment, and the treatment of net export revenues as a system dividend are examples of policy or other ratemaking considerations that were embedded in the COS, and were therefore explicitly reflected in the RCC outputs of those studies. Order 164/16 modified the methodology to remove those influences from the COSS, and now require Manitoba Hydro and the PUB to address those considerations at the ratemaking stage.

RCCs provide a measure of the cost coverage, as defined by the COSS, against class revenues. The ratios provide some indication of the degree of cross subsidy that may exist among customer classes. However, there may be other compelling policy reasons for the PUB to accept a certain RCC outcome for a customer class, regardless of the cost coverage that has been measured. If the PUB determines that there is sufficient reason to afford one customer class rates that produced more or less than their allocated cost, it has the authority to do so. While class RCCs provide a measure of cost coverage, the PUB ultimately has the authority to take into consideration policy or other factors and find those rates to be just and reasonable, and neither unduly discriminatory nor unduly preferential.

---

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 the GRA."

Manitoba Hydro applies to the PUB for approval of electricity rates and subject to their regulatory review the PUB has approved rates that it deems to be just and reasonable. Given the rates are deemed just and reasonable, the range of RCC ratios resulting from these approved rates must, by extension, have also been accepted as just and reasonable. The inverse of that is also true. Had the degree that RCCs varied from the ZOR been deemed not just and reasonable, rate adjustments would have been made, and in fact were made periodically by the PUB. Figure 8.15 in Tab 8 of the Application shows the historic range of RCC outcomes from 17 different cost of service studies, from PCOSS18 back to PCOSS95. While the range of RCC outcomes has been as great as 90-120% (PCOSS95) and as tight as 97-109% (PCOSS02), the figure shows that the range of outcomes generally falls within a bandwidth of 90-110%.

The PUB, after considering policy and rate making objectives, may deem rates to be reasonable, even if revenues recover more or less costs that can be targeted to fall within the previous zone of 95-105%. A sufficiently broad Zone of Reasonableness of 90%-110% may be reasonable in light of historical precedence and continuity, ratemaking and policy objectives, the degree of variability in cost allocation methodologies and cost definition and the changing cost structure in future rate applications due to the significant infrastructure investment underway for Manitoba Hydro.

b) The annual differentiation in class rate changes required to achieve a Revenue Cost Coverage ratio, over the time periods requested, are show below. This analysis excludes the impact of any general revenue increase.

i. Achieve Unity (RCC's = 100%)

	Annual Differentiation 1 Year	Annual Differentiation 5 Years	Annual Differentiation 10 Years	Final RCC
Residential	6.9%	1.3%	0.7%	100.0%
GSS Non Demand	-13.6%	-2.9%	-1.5%	100.0%
GSS Demand	-1.3%	-0.3%	-0.1%	100.0%
GSM	2.2%	0.4%	0.2%	100.0%
GSL 0-30kV	1.3%	0.3%	0.1%	100.0%
GSL 30-100kV	-11.5%	-2.4%	-1.2%	100.0%
GSL >100kV	-11.0%	-2.3%	-1.2%	100.0%
Area & Roadway Lighting	-0.3%	-0.1%	0.0%	100.0%

ii. Within Zone of Reasonableness (95-105%)

	Annual Differentiation 1 Year	Annual Differentiation 5 Years	Annual Differentiation 10 Years	Final RCC
Residential	0.2%	0.0%	0.0%	95.0%
GSS Non Demand	-8.2%	-1.7%	-0.8%	105.0%
GSS Demand	0.0%	0.0%	0.0%	101.0%
GSM	0.0%	0.0%	0.0%	98.3%
GSL 0-30kV	0.1%	0.0%	0.0%	99.1%
GSL 30-100kV	-5.3%	-1.1%	-0.5%	105.0%
GSL >100kV	-4.6%	-0.9%	-0.5%	105.0%
Area & Roadway Lighting	0.0%	0.0%	0.0%	100.3%

REFERENCE:

PUB/MH I-137b i & ii RCC cost parity scenarios

PREAMBLE TO IR (IF ANY):

QUESTION:

Do the annual rate changes shown in the tables provided in response to PUB/MH I-137b i & ii produce revenue neutrality in total for Manitoba Hydro during each year of the scenario periods? If yes, then why in the table provided in response to 137b ii, under the 5 and 10 year columns, are rate decreases shown for certain rate classes with no offsetting increases for other classes? If any/all of the data shown for any given scenario do not produce revenue neutrality in total across all rate classes, please recalculate the table results assuming revenue neutrality for Manitoba Hydro is maintained under all scenarios.

RATIONALE FOR QUESTION:

RESPONSE:

The annual rate changes required to reach unity as provided in Manitoba Hydro's response to PUB/MH I-137b(i) are revenue neutral in totality. However, the annual changes shown in PUB/MH I-137b(ii) did not reflect required increases to classes to balance the revenues for neutrality.

The table below is a revision to PUB/MH I-137b(ii) that provides the annual rate changes required to move all classes into the zone of reasonableness, while maintaining overall revenue neutrality. The revenue shortfall that results from the rate decreases for the GSS ND, GSL 30-100 kV and GSL>100 kV classes is assumed to be recovered from the Residential class who has the lowest RCC of the classes. With the additional rate increases the Residential class's RCC is 97.5% which is above the lower bound of the ZOR, but remains the lowest of all classes.

PUB/MH I-137b(ii) REVISED

Within Zone of Reasonableness (95-105%) – Revenue Neutral

	Annual Differentiation 1 Year	Annual Differentiation 5 Years	Annual Differentiation 10 Years	Final RCC
Residential	3.6%	0.7%	0.4%	97.5%
GSS Non Demand	-8.2%	-1.7%	-0.8%	105.0%
GSS Demand	0.0%	0.0%	0.0%	101.0%
GSM	0.0%	0.0%	0.0%	98.3%
GSL 0-30 kV	0.1%	0.0%	0.0%	99.1%
GSL 30-100 kV	-5.3%	-1.1%	-0.5%	105.0%
GSL >100 kV	-4.6%	-0.9%	-0.5%	105.0%
Area & Roadway Lighting	0.0%	0.0%	0.0%	100.3%

REFERENCE:

PUB/MH I-137b i & ii; MIPUG/MH I-23b; Coalition/MH I-119

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please recalculate the responses provided to PUB/MH I-137b i & ii to include the impacts of the uniform 7.9% rate increases sought in this proceeding.
b) Please recalculate the responses provided to PUB/MH I-137b i & ii to include the impacts of the uniform 7.9% rate increases sought in this proceeding *and* Bipole III coming into service.

In regards to both (a) and (b), please provide results after including any changes that may be required after preparing the response to PUB/MH II - 87.

c) Please provide the class rate changes in 2018/19 and the resulting RCC ratios required incorporating the following objectives:
   i. Revenue neutrality (i.e. to achieve the requested revenue in IFF16-Updated with Interim)
   ii. Move each class within (or towards) a zone of reasonableness of 95% to 105%
   iii. Maintain Manitoba Hydro's guidelines that no class should experience a class revenue increase more than 2% greater than the overall general revenue increase. Note: class revenue decreases should also not exceed 2% in this analysis.

RATIONALE FOR QUESTION:

RESPONSE:

a) The table below provides the annual rate differentiation required to move all classes to unity, while maintaining overall revenue neutrality. The initial class RCCs reflect the impact of the uniform 7.9% rate increase.

Achieve Unity (RCC's = 100%)

	Initial RCC including Impact of Uniform 7.9% Increase[1]	Annual Differentiation 1 Year	Annual Differentiation 5 Years	Annual Differentiation 10 Years	Final RCC
Residential	95.1%	6.5%	1.3%	0.6%	100.0%
GSS Non Demand	112.7%	-13.7%	-2.9%	-1.5%	100.0%
GSS Demand	100.9%	-1.2%	-0.2%	-0.1%	100.0%
GSM	98.0%	2.6%	0.5%	0.3%	100.0%
GSL 0-30 kV	98.7%	1.8%	0.4%	0.2%	100.0%
GSL 30-100 kV	109.0%	-11.0%	-2.3%	-1.2%	100.0%
GSL >100 kV	108.1%	-10.3%	-2.2%	-1.1%	100.0%
Area & Roadway Lighting	101.2%	-1.3%	-0.3%	-0.1%	100.0%

The table below provides the annual rate differentiation required to move all classes into the zone of reasonableness, while maintaining overall revenue neutrality. The initial class RCCs reflect the impact of the uniform 7.9% rate increase.

The revenue shortfall that results from the below average rate changes for the GSS ND, GSL 30-100 kV and GSL >100 kV classes is assumed to be recovered entirely from the Residential class. With the additional rate increases the Residential class's revised RCC of 97.7% is above the lower bound of the ZOR, but remains the lowest of all classes.

[1] As provided in Manitoba Hydro's response to PUB/MH I-132c

Within Zone of Reasonableness (95-105%)

	Initial RCC including Impact of Uniform 7.9% Increase[1]	Annual Differentiation 1 Year	Annual Differentiation 5 Years	Annual Differentiation 10 Years	Final RCC
Residential	95.1%	3.4%	0.7%	0.3%	97.7%
GSS Non Demand	112.7%	-8.3%	-1.7%	-0.9%	105.0%
GSS Demand	100.9%	0.0%	0.0%	0.0%	100.9%
GSM	98.0%	0.0%	0.0%	0.0%	98.0%
GSL 0-30 kV	98.7%	0.0%	0.0%	0.0%	98.7%
GSL 30-100 kV	109.0%	-4.9%	-1.0%	-0.5%	105.0%
GSL >100 kV	108.1%	-4.0%	-0.8%	-0.4%	105.0%
Area & Roadway Lighting	101.2%	0.0%	0.0%	0.0%	101.2%

b) The table below provides the annual rate differentiation required to move all classes to unity, while maintaining overall revenue neutrality. The initial class RCCs reflect the estimated impact of Bipole III coming into service.

Achieve Unity (RCC's = 100%)

	Initial RCC including BPIII[2]	Annual Differentiation 1 Year	Annual Differentiation 5 Years	Annual Differentiation 10 Years	Final RCC
Residential	96.7%	4.1%	0.8%	0.4%	100.0%
GSS Non Demand	115.3%	-15.4%	-3.3%	-1.7%	100.0%
GSS Demand	101.3%	-1.5%	-0.3%	-0.2%	100.0%
GSM	97.4%	3.2%	0.6%	0.3%	100.0%
GSL 0-30 kV	96.5%	4.5%	0.9%	0.4%	100.0%
GSL 30-100 kV	103.5%	-4.3%	-0.9%	-0.4%	100.0%
GSL >100 kV	101.5%	-1.9%	-0.4%	-0.2%	100.0%
Area & Roadway Lighting	118.2%	-16.1%	-3.5%	-1.7%	100.0%

[2] As provided in Manitoba Hydro's response to MIPUG/MH I-23a-b. Please note that in this scenario the funds from the amortization of the BPIII reserve account are distributed equally based on class revenues.

The table below provides the annual rate differentiation required to move all classes into the zone of reasonableness, while maintaining overall revenue neutrality. The initial class RCCs reflect the estimated impact of Bipole III coming into service.

The revenue shortfall that results from the below average rate changes for the GSS ND and A&RL classes is assumed to be recovered from all classes below unity, and is distributed between the Residential, GSM and GSL 0-30 kV classes such that the final RCC for all three is equivalent.

Within Zone of Reasonableness (95-105%)

	Initial RCC including BPIII[2]	Annual Differentiation 1 Year	Annual Differentiation 5 Years	Annual Differentiation 10 Years	Final RCC
Residential	96.7%	2.2%	0.4%	0.2%	98.5%
GSS Non Demand	115.3%	-10.3%	-2.2%	-1.1%	105.0%
GSS Demand	101.3%	0.0%	0.0%	0.0%	101.3%
GSM	97.4%	1.3%	0.3%	0.1%	98.5%
GSL 0-30 kV	96.5%	2.5%	0.5%	0.2%	98.5%
GSL 30-100 kV	103.5%	0.0%	0.0%	0.0%	103.5%
GSL >100 kV	101.5%	0.0%	0.0%	0.0%	101.5%
Area & Roadway Lighting	118.2%	-11.7%	-2.5%	-1.2%	105.0%

c) The table below provides an illustrative example of annual rate changes that would achieve the stated objectives of:

i. achieving the proposed overall 7.9% increase in revenue;
ii. moving all class within (or towards) the zone of reasonableness; and
iii. where the rate increase for each class is within +/-2% of the overall 7.9% increase.

A rate increase 2.0% below the overall increase was initially applied to the GSS ND, GSL 30-100 kV and GSL >100 kV classes whose RCCs were above the upper bound of the zone of reasonableness. Applying the minimum allowable rate increase was not sufficient to move any of the classes into the ZOR.

The RCC for the GSS D, GSM, GSL 0-30kV and A&RL classes are within the ZOR, and are assumed to receive levels of rate differentiation sufficient to maintain their initial RCC.

To achieve revenue neutrality the Residential class can only receive a rate increase 1.3% higher than average, which moves the class into the ZOR at 95.8%.

Incorporating Rate Design Objectives Stated in Part c).

	Initial RCC	Rate Change 1 Year	Final RCC
Residential	94.8%	9.2%	95.8%
GSS Non Demand	112.5%	5.9%	111.1%
GSS Demand	101.0%	7.8%	101.0%
GSM	98.3%	7.9%	98.3%
GSL 0-30 kV	99.1%	8.2%	99.1%
GSL 30-100 kV	109.3%	5.9%	107.4%
GSL >100 kV	108.6%	5.9%	106.7%
Area & Roadway Lighting	100.3%	6.6%	100.3%

108

The Coalition argues that some directly assigned costs, such as street light luminaires, should not be included in the allocation base for NER as these assets are not an integral part of Manitoba Hydro's obligation to serve.

The positions of GSS/GSM and the City of Winnipeg are that NER should be credited on the basis of a class's share of total costs. Manitoba Hydro changed its final proposed methodology of crediting NER to align with GSS/GSM's and the City of Winnipeg's proposed methodology. These interveners and Manitoba Hydro agree that this approach minimizes unfair crediting of NER and results in a more equitable allocation process.

GAC supports crediting NER on the basis of total costs as a matter of fairness, and recommends including directly assigned costs in the calculation of the NER credit, but excluding directly assigned dedicated end-use facilities such as street lighting.

MIPUG departs from the other interveners and recommends that NER be excluded from the COSS, arguing that this approach is consistent with maintaining a principled COSS study and avoids class-specific advocacy. MIPUG's view is that NER is not a cost, but rather is revenue that is not inherently linked to embedded costs. MIPUG recommends that RCC ratios for the domestic classes absent any NER credit can be used to set rates. Over time, once the RCC ratios are brought closer to unity, then there are other possible options for the treatment of NER if it is excluded from the COSS, but MIPUG submits that these issues do not need to be resolved at this time.

MIPUG's alternative position is that if NER is included in the COSS, it should be credited against Generation and Transmission costs only as those are the assets that give rise to the export revenue.

Board Findings

The Board finds that export revenue should be credited to the domestic classes based only on each class's share of total 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 export revenues. The Board finds that the Distribution system is not utilized to effect export sales.

The Board finds that there is no cost of service reason to credit export revenue on a basis that includes Subtransmission, Distribution, and Customer Service. Manitoba Hydro's crediting of export revenue on total costs is based on Manitoba Hydro's approach of integrating ratemaking goals into the COSS. As the Board has stated above, those goals are to be considered at the final ratemaking stage.

Manitoba Hydro asserts that export sales are made possible by freed up energy and capacity occurring at times of low use on the Distribution system, and that this justifies crediting export revenues on a basis that includes Distribution costs in addition to Generation and Transmission. In response to this, the Board-approved methodology for the allocation of Generation and Transmission costs already recognizes the fact that a large portion of the energy that is available for exports results from lower domestic customer use of Generation and Transmission costs in certain seasons or hours. The Board-approved methodology specifies that the largest portion of Generation costs is allocated on an Energy basis, which recognizes the lower use in certain seasons or hours. Manitoba Hydro's argument focuses on the fact that the lower loads of the Distribution-connected classes create the export opportunity, when in fact the lower loads have already been recognized through the lower allocation of the costs with the Energy classification.

It does not logically follow that, because periods of low demand on the distribution system create opportunities to export, Distribution costs should be part of the basis for crediting export revenues. Regardless of the variation in distribution system load, Distribution costs – that is the costs of distribution substations, transformers, poles, wires, meters, and services – do not vary with export load. There is no cost causation basis for crediting export revenues to defray these costs, which are solely a function of maximum class demand and number of customers on Manitoba Hydro's system.

The Board finds that the revenue from export sales is linked to the assets that give rise to export sales revenues, which are Generation and Transmission assets only, not Distribution assets. To use Distribution costs to credit export revenue of any kind would be a disconnection to cost causation and thus inappropriate.

The Board concludes that export revenues are not a “dividend” that can be assigned or based on considerations other than cost causation. Cost causation of export revenues was illustrated in the Board’s 2014 review of the Keeyask and Conawapa generating station projects as part of the Needs For and Alternatives To (“NFAT”) review. Manitoba Hydro’s economic justification for these projects and the Board’s NFAT recommendations were based on using the full quantum of export revenues to lower the cost of the new Generation and Transmission assets. Distribution costs were not relevant in the justification of the NFAT’s economic case. The eventual benefits that are to flow to Manitoba Hydro’s customers from the recommended NFAT development plan are appropriately shared among the domestic classes if they are shared on the same basis as the costs are apportioned. Crediting export revenues on a basis other than Generation and Transmission misdirects benefits to some domestic classes at the expense of others. This further affirms the rationale for crediting export revenues on the basis of Generation and Transmission costs allocated to domestic classes.

If the COSS methodology is driven by considerations other than cost causation, then the final results of the COSS are muddled. Allocation of NER based on Generation, Transmission, and Distribution results in an increased subsidy to Distribution-connected customer classes (such as Residential and GSS). When considering the RCC ratios in a GRA, the true ratios are skewed because of the NER subsidy. Subsidies within the COSS are challenging to disentangle at the ratemaking stage. The Board is of the view that additional transparency is achieved with the COSS and the ratemaking process if these implicit or explicit subsidies are eliminated from the COSS.

REFERENCE:

Rudimentary Model of PCOSS18.xlsx

PREAMBLE TO IR (IF ANY):

QUESTION:

Similar to the schedule provided on the "Reference Scenario RCC Summary" tab, can Manitoba Hydro provide a schedule of RCCs for all customer classes after each class' allocated NER revenue is deducted from its total cost, i.e. Total Revenue/ (Total Cost – Allocated NER).

RATIONALE FOR QUESTION:

To clarify the magnitude of rate balancing forgone in Manitoba Hydro's Application.

RESPONSE:

Manitoba Hydro calculates the Revenue Cost Coverage for each customer class by adding class revenues to the classes' share of Net Export Revenues and then dividing those combined revenues by the allocated cost for the class. This methodology has been utilized by Manitoba Hydro in each of its cost of service studies since 1979.

The following table provides the results of PCOSS18 produced by applying Net Export Revenues as a cost reduction in the Revenue Cost Coverage ratio calculation instead of as an addition to Class Revenue as discussed above.

While the alternative approach suggested in this question is plausible, that method generates results with a much broader set of RCC outcomes (93.5 to 115.7) when compared to the current method (94.8 to 112.5). The difference between the two methods is significant but will decrease as RCCs approach unity.

The difference in results that occurs using two reasonable approaches illustrates the impact that judgment can have on the results of the study, and the need to use a Zone of Reasonableness when applying the results of the PCOSS.

	(a) Total Cost ($000)	(b) Class Revenue ($000)	(c) Net Export Revenue ($000)	PCOSS18 RCC (b+c)/a	**Alternate RCC b/(a-c)**	RCC Change
Residential	810,916	607,106	161,911	94.8%	**93.5%**	-1.3%
GSS Non Demand	151,814	139,479	31,313	112.5%	**115.7%**	3.2%
GSS Demand	185,200	146,983	40,099	101.0%	**101.3%**	0.3%
GSM	253,466	191,737	57,472	98.3%	**97.8%**	-0.5%
GSL 0-30 kV	120,404	89,652	29,613	99.1%	**98.7%**	-0.4%
GSL 30-100 kV	86,975	69,995	25,054	109.3%	**113.0%**	3.7%
GSL >100 kV	230,688	180,458	70,042	108.6%	**112.3%**	3.7%
A&RL	22,987	21,571	1,482	100.3%	**100.3%**	0.0%

REFERENCE:

Appendix 8.1, Page 2

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a schedule of rate increases that would be required to target customer class Revenue to Cost Comparison (RCC) ratios of 100% for each class over 5 years, based on PCOSS18 results.

b) Please provide a schedule of estimated rate increases that would be required to target customer class RCC ratios of 100% for each class over 5 years including estimated impacts on the PCOSS from Bipole III coming into service.

RATIONALE FOR QUESTION:

RESPONSE:

a) Please see Manitoba Hydro's response to PUB/MH 1-137 which provides required increases by class to reach 100% in 5 years.

b) To provide a high level indication of the anticipated shift in functionalized costs and revenue cost ratios once Bipole III is placed in service, the following assumptions have been made:

- The estimated carrying and operating costs of the major new G&T projects as provided in PUB MFR 20 are functionalized and added to the PCOSS18 revenue requirement as follows:
    - Additional DSM and Conawapa: Financing of Sunk Costs have been added to the Generation function
    - BPIII and Riel convertor station costs, excluding the Riel 230/500 kV Station that is already included in PCOSS18 Transmission, have been functionalized as Generation.

- The residual revenue requirement, which was not specifically attributed to a new major G&T project, is assumed related to existing assets and has been functionalized by cost category in proportion to the PCOSS18 revenue requirement.
- The funding provided by amortization of the Bipole III Reserve Account has been distributed equally based on class revenues as described in the response to PUB/MH 1-139.
- Domestic revenues were adjusted on an across-the-board basis in order to offset the remaining increase in revenue requirement.

The following table shows the additional annual differentiation in class rate changes required to achieve a Revenue Cost Coverage ratio of unity in five years, after including the estimated impacts of Bipole III.

	Estimated 2020 RCC with BPIII In Service	Annual Differentiation 5 Years
Residential	96.7%	0.80%
GSS Non Demand	115.3%	-3.29%
GSS Demand	101.3%	-0.30%
GSM	97.4%	0.64%
GSL 0-30 kV	96.5%	0.88%
GSL 30-100 kV	103.5%	-0.88%
GSL >100 kV	101.5%	-0.39%
Area & Roadway Lighting	118.2%	-3.46%

109

MANITOBA HYDRO
2017/18 & 2018/19 GENERAL RATE APPLICATION

LETTER OF APPLICATION

IN THE MATTER OF: *The Crown Corporations Public Review & Accountability Act*

An Application by Manitoba Hydro for an Order of the Public Utilities Board Approving Increases to Electricity Rates

TO: The Executive Director of the
Public Utilities Board of Manitoba
Winnipeg, Manitoba

Manitoba Hydro hereby applies to the Public Utilities Board of Manitoba ("PUB") for an Order pursuant to *The Crown Corporations Public Review & Accountability Act* for the following:

1. Final approval of Order 59/16 which approved, on an interim basis, an across-the-board rate increase of 3.36% effective August 1, 2016, and final approval of any other interim rate Orders issued subsequent to the filing of the Application and prior to the conclusion of this proceeding;

2. Approval, on an interim basis, of rate schedules incorporating an across-the-board rate increase of 7.9% to all components of the rates for all customer classes to be effective August 1, 2017;

3. Approval of an across-the-board rate increase of 7.9% to all components of the rates for all customer classes to be effective April 1, 2018;

4. Final approval of the Light Emitting Diode ("LED") rates for the Area and Roadway Lighting class (Outdoor Lighting) approved on an interim basis in Order 79/14, and approval of new LED rates for the Area and Roadway Lighting class (Sentinel Lighting) as discussed in Tab 9 of this Application;

5. Approval to remove the Area and Roadway Lighting (Festoon Lighting) and the Area & Roadway Lighting (Christmas Lighting) from Manitoba Hydro's rate schedule, as discussed in Tab 9 of this Application;

6. Endorsement of modifications to the Terms and Conditions of Option 1 of the Surplus Energy Program ("SEP") that were accepted on an interim basis in Order 43/13, as outlined in Tab 9 of this Application;

7. Final approval of all SEP interim *ex parte* rate Orders as set forth in Tab 10 of this Application, as well as any additional SEP *ex parte* Orders issued subsequent to the filing of this Application and prior to the PUB's Order in this matter;

8. Final approval of CRP *ex parte* Order 54/16 as well as any additional *ex parte* Orders in respect of the CRP issued subsequent to the filing of this Application and prior to the PUB's Order in this matter;

9. Final approval of Orders 116/12 and 117/12 that approved, on an interim basis, a 6.5% rate increase to the full cost portion of the General Service and Government rates in the four remote communities served by diesel generation effective September 1, 2012, and final approval of diesel zone interim Orders 17/04, 46/04, 159/04, 176/06, 1/10, 134/10, 1/11 and 148/11, subject to confirmation that MKO has provided the parties to the agreement with the required affidavits from representatives of signatories to the agreement;

10. Endorsement of the proposed deferral and subsequent amortization of costs incurred with respect to the Conawapa Generating Station project, as discussed in Tab 4 of this Application; and

11. Endorsement of the proposed amortization period for disposition of the regulatory deferral accounts established to capture the differences between Depreciation Expense and Operating & Administrative Expense calculated for financial reporting purposes based on International Financial Reporting Standards, and Depreciation Expense and Operating & Administrative Expense calculated for rate-setting purposes reflecting PUB directives in Order 73/15. Further details are discussed in Tab 4.

As part of its Application, Manitoba Hydro is requesting that the PUB approve a 7.9% rate increase on an interim basis effective August 1, 2017. This will result in an increase of $6.88 in the monthly bill of a residential customer without electric space heat, using an average of 1,000 kilowatt-hours ("kWh") per month, and an increase of $13.14 in the monthly bill of a residential customer with electric space heat, using an average of 2,000 kWh per month. Manitoba Hydro is also requesting the PUB approve a further 7.9% rate increase effective April 1, 2018. This will result in a further increase of $7.43 in the monthly bill of a residential customer without electric space heat, and a further increase of $14.19 in the monthly bill for a residential customer with electric space heat.

Approval of the rate increases proposed in this Application is required to improve the financial position of the corporation. In making this Application, Manitoba Hydro has considered customer sensitivity to rate increases as well as the financial position of the corporation, and believes that the proposed rate increases provide an appropriate balance between addressing the financial risks of the corporation and managing the impact of rate increases on customers.

The circumstances giving rise to the rate increases will be discussed in Tab 2 of the Application. Further information in support of the Application will be provided in Tab 3 to Tab 11.

66

Communication related to this Application should be addressed to Manitoba Hydro in the following fashion:

Manitoba Hydro
Attention: Patricia J. Ramage
22nd Floor, 360 Portage Avenue
Winnipeg, Manitoba
R3C 0G8

Telephone No. (204) 360-3946
Fax No. (204) 360-6147
E-Mail: pjramage@hydro.mb.ca

DATED at Winnipeg, Manitoba this 5th day of May, 2017.

MANITOBA HYDRO

"ORIGINAL SIGNED
BY PATRICIA J. RAMAGE"

Per: ____________________
Patricia J. Ramage

4. Manitoba Hydro is seeking approval of new Light Emitting Diode ("LED") rates for the Area and Roadway Lighting class (Sentinel Lighting), and final approval of LED rates for the Area and Roadway Lighting class (Outdoor Lighting) approved on an interim basis in Order 79/14. Manitoba Hydro is proposing to eliminate the Area and Roadway Lighting class (Festoon Lighting) rate and the Area and Roadway Lighting class (Christmas Lighting) rate. Neither of these rates had customers billing on them.

9.1 GENERAL RATE MAKING OBJECTIVES

Manitoba Hydro's general rate making objectives are as follows:

1. Recovery of Revenue Requirement – Rates must provide the Corporation the opportunity to fully recover its allowed revenue requirement.

2. Fairness and Equity – Rate design should provide for equitable treatment of customers both within a customer class (whereby similar customers receive similar treatment) and between customer classes (whereby dissimilar customers may be treated differently).

3. Rate Stability and Gradualism – In conformity with the principles of gradualism and sensitivity to customer impacts, annual adjustments to revenues by customer class should be less than two percentage points greater than the overall proposed increase.

4. Efficiency – Manitoba Hydro views this goal in designing rates as the need to provide appropriate price signals regarding the value of energy and to promote the efficient and economic use of energy. The determination of an appropriate price signal may recognize the application of marginal cost considerations.

5. Competitiveness of Rates - Maintain Manitoba Hydro's competitive position with respect to rates charged by other Canadian utilities for all rate classes.

6. Simplicity and Understandability – Rate design should be understandable to customers and should be easy to interpret and apply.

REFERENCE:

Tab 9, Page 4, lines 27-31

PREAMBLE TO IR (IF ANY):

QUESTION:

What is Manitoba Hydro's view as to the maximum bill impact (in percentage terms) that should be imposed on an individual customer as a result of both overall rate increases, revenue to cost ratio adjustments and rate structure changes? Please provide any supporting policy documentation.

RATIONALE FOR QUESTION:

To understand role of bill impact considerations in implementing rate structure changes.

RESPONSE:

Manitoba Hydro's financial forecast determines the overall proposed revenue increase required for Manitoba Hydro's financial health in order to maintain safe and reliable service.

The impact of possible revenue adjustments between rate classes to address RCC considerations and the impact of potential rate structure changes within customer classes deserve consideration as not to unduly impact affected customers.

In this regard, Manitoba Hydro refers to its rate design goal shown at lines 26 to 29 on page 2 of Tab 9 of the GRA. The goal of Rate Stability and Gradualism recommends that the annual adjustments to revenues by customer class should be less than two percent greater than the overall proposed increase. Given the overall proposed increase of 7.9% in this Application any proposed shift in revenues between customer classes should be limited to a maximum increase, to the most affected customer class, of less than 9.9%.

In past filings, Manitoba Hydro included rate making objectives that provided guidance for the combination of revenue adjustments between classes and for rate design adjustments within a class.

For example, in its 2015/16 & 2016/17 GRA, Manitoba Hydro stated the following in its Rate Objectives on pages 2 and 3 of Tab 6 of that Application:

- "In conformity with the principles of gradualism and sensitivity to customer impact, annual adjustments to revenues by customer class are less than two percentage points greater than the overall proposed increase."

And;

- "The combined impact of proposed class average rate increases and adjustments to rate structure results in customer monthly impacts which fall within Manitoba Hydro's guidelines:
  - For Residential customers, no customer will experience a bill increase which exceeds the greater of $3.00 per month or three percentage points more than the class average increase.
  - For General Service customer, no customer will experience an increase in their average monthly bill over a year which exceeds the greater of $5.00 per month or five percentage points more than the class average increase."

Manitoba Hydro recommends that a threshold of less than 2% be maintained in considering the effect of potential revenue adjustments between customer classes.

While Manitoba Hydro did not propose any rate design changes in its initial Application, the above guidance is applicable in the event that a rate design change is considered by the PUB.

110

1.2 SUMMARY OF RECOMMENDATIONS

1. Finalize the previous two interim rate increases at the 3.36% level awarded.
2. Reject proposals for increases of 7.9%/year.
3. Implement a rate increase for the 2018/19 year at a level consistent with recent experience, at 3.36% (not on an across-the-board basis).
4. Forecasts related to reducing the Weighted Average Term to Maturity of new debt to the 12 year range should be included in Hydro's IFF projections.
5. Hydro should be encouraged to fully pursue O&A expense reductions, including to plan to achieve levels at or below earlier levels (e.g., 2011/12 or before) plus inflation.
6. Direct a $20 million capitalization of overheads/year indefinitely, amortized over 30 years.
7. Direct the implementation of depreciation rates consistent with the ASL procedure, with no reversion to ELG procedure in the financial forecast, and no amortization of the difference in rates at any time.
8. DSM spending assumptions should be based on significantly reduced DSM spending, on the understanding that future DSM reviews will be based on principled Integrated Resource Planning, and should not be assumed to target 1.5%/year savings or spending levels by rote. This should include direction that the currently deferred $48.8 million in DSM funding from past years not be spent unless justified as part of a DSM plan.
9. Rates for industrial customer classes that are above the Zone of Reasonableness should see a lower than average increase, such as 1-2% below average, consistent with past PUB practice in Order 7/2003.
10. The calculation of Revenue to Cost ratios should be based on measured costs (net of export revenues) to class rates.
11. An optional Time of Use rate design should be reviewed for the large industrial classes, based on customers opting in if they see benefits. To the extent there are lost revenues arising to Hydro from such a program, these amounts are expected to be considerably less than the degree to which industrial customer classes currently pay rates above costs, and therefore can be absorbed within the assigned costs to the industrial classes in the Cost of Service study without requiring increases to other industrial customers.

setting industrial rates, which can, at times, undermine other rate redesign objectives such as rate stability. Outside of such consideration, there is no reasonable basis to ignore a valid, regulatory-approved COS result in setting rates by class.

For the GSL >100kV customers to even reach a 105% RCC a substantial one-time rate decreases would be required of approximately 0.26 cents/kW.h (GSL >100 kV costs at 3.57 cents/kW.h, at 105% this yields 3.75 cents/kW.h – compare to current rates at 4.01 cents/kW.h). To large power users, continuing to pay energy rates at a level this much higher than costs has implications to competitiveness and economics.

However, among the considerations that should be brought to bear on such rate adjustments is long-term stability. Hydro notes that Bipole III is coming into service, but is not yet included in the PCOSS. While a PCOSS fully incorporating Bipole III has not yet been prepared, it is clear that this asset will drive bulk power costs in the COS study notably higher (even when Bipole III costs are offset by the Bipole III revenue deferral amortization). This does not limit the Board from providing improvements to the RCC ratio by awarding lower than average rate increases to industrials of, for example, 1-2% below the average rate increase awarded (similar to the Board's decision in Order 7/2003), but does suggest caution in regards to large moves such as calculated above (i.e., a reduction of the full 0.26 cents/kW.h at one time is not advised).

7.2.1 Time of Use (TOU) Rates

Hydro had previously applied for Time of Use ("TOU") rates in the 2015/16 GRA; however the Board determined it would be addressed in the Cost of Service review, and these rates were ultimately not reviewed at that GRA[235]. In the Cost of Service review rate-related matters, including rate rebalancing, time-of-use rates and conservation rates were excluded from the scope of the Cost of Service methodology review to the next GRA[236] (i.e. this proceeding).

Hydro did not submit a TOU rate proposal in this GRA. Hydro is not proposing to implement TOU rates in this application as Hydro has generally only considered TOU rates as a mandatory change to the industrial rate schedule affecting all customers, and as a result under Hydro's concept of a TOU rate there would be 'winners and losers'. Specifically, some customers who would be charged this rate, such as high load factor customers who are unable to shift production to off-peak periods, would be burdened, essentially funding any bill reductions to the customers that can make use of off-peak time periods to reduce costs.[237] This is a difficult challenge to the implementation of Hydro's concept at the best of times, but particularly so when facing a 7.9% rate increase proposal.

[235] Order 73/15, page 89 of 90
[236] Order 26/16, page 16
[237] Tab 9, page 4

REFERENCE:

Tab 9 Page 2 of 18

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide the marginal values used by Manitoba Hydro in its rate design and DSM cost effectiveness evaluations.

RATIONALE FOR QUESTION:

RESPONSE:

The levelized marginal cost values used in the evaluation of the cost effectiveness of Manitoba Hydro's DSM programs as presented in Appendix 7.2 of Tab 7 (2016 Demand Side Management Plan) are as follows:

Generation	6.34₵/kWh
Transmission	0.56₵/kWh
Distribution	0.87₵/kWh
Total	7.77₵/kWh

The levelized marginal values noted above are also useful in rate design, as the determination of an appropriate price signal may recognize the application of marginal cost considerations, as mentioned in Manitoba Hydro's general rate making objectives discussed on page 2 of Tab 9.

The above values correspond to the marginal cost evaluation information shown in Figure 8.14 on page 31 of Tab 8.

REFERENCE:

Tab 9 Page 2 of 18

PREAMBLE TO IR (IF ANY):

QUESTION:

b) Please provide the derivation of the marginal values.

c) Please explain whether the changes in the export revenue forecast, including the decline in export price forecasts and the elimination of premiums associated with the sale of long term dependable energy and capacity, are reflected in the current marginal value.

RATIONALE FOR QUESTION:

RESPONSE:

b) Marginal value is defined as the cost or value to the system of deferring an increment of load growth to Manitoba Hydro's integrated system. Since the power supplied to residential load requires generation supply, bulk transmission capability and distribution capability, a marginal value has been determined for each of these three components. The transmission and distribution components are based on one-year deferral of planned transmission and distribution capital additions to meet the ongoing capacity requirements. Please see Manitoba Hydro's response to GAC/MH I-39 for the transmission and distribution marginal cost reports.

The generation marginal value represents value of the energy savings on the export market when valued as a long-term firm sale, and incorporates all the associated system costs in order to facilitate the sale. The production costs are determined by undertaking a simulation of system operation for 35-years into the future using an in-house computer model for a wide range of flow cases.

The first simulation run is a base case which corresponds to the IFF case. In order to determine marginal value, a second simulation is undertaken in which the load is reduced from the base case by a constant increment in each month for a total of 500 GWh over the year as an example. The net difference in production costs between the two simulations for each year of the study period is divided by the energy associated with the incremental load change to derive the marginal generation value in dollars per megawatt hour. Transmission and distribution losses are also calculated and added to the generation component to account for the full quantity of generation that is required to serve the end use load. Values are calculated for the summer and winter seasons, and on an annual basis.

The following table contains marginal values used in the 2016 DSM plan (Appendix 7.2). The generation marginal cost values are derived from and are very closely related to the electricity export price forecast which is confidential and commercially sensitive information. Public disclosure of portions of this response would result in the release of information considered to be confidential and commercially sensitive. As directed by the PUB, Manitoba Hydro will be filing a motion seeking confidential treatment of the redacted information contained in this response pursuant to Rule 13.

2015/16 Basic Marginal Costs Applicable to Distribution Level Programs
Marginal Costs Given at Distribution
(Constant Year 2016 Canadian Dollars)

Notes:
Marginal costs based on a uniform supply with a 100% capacity factor
Marginal costs referred to distribution level (loss factor of 14% to translate back to generation)
US/Cdn Exchange Rates and Escalation Factors (P911 October 12, 2015)
Updated transmission & distribution marginal costs (2015)

5a

Fiscal Year	SUMMER		WINTER					ALL-IN		
	Generation Energy	Generation Capacity	Generation Energy	Generation Capacity	Transmission Capacity	Distribution Capacity	Total Capacity	SUMMER	WINTER	ANNUAL
	$/MW.h	$/kW.Yr	$/MW.h	$/kW.Yr	$/kW.Yr	$/kW.Yr	$/kW.Yr	$/MW.h	$/MW.h	$/MW.h
2016/17	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2017/18	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2018/19	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2019/20	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2020/21	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2021/22	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2022/23	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2023/24	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2024/25	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2025/26	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2026/27	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2027/28	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2028/29	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2029/30	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2030/31	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2031/32	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2032/33	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2033/34	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2034/35	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2035/36	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2036/37	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2037/38	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2038/39	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2039/40	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2040/41	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2041/42	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2042/43	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2043/44	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2044/45	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
2045/46	[redacted]	[redacted]	[redacted]	[redacted]	49 3	76 5	[redacted]	[redacted]	[redacted]	[redacted]
Levelized Cost at 4.15% Discount Rate	[redacted]	[redacted]	[redacted]	[redacted]	49.28	76.48	[redacted]	[redacted]	[redacted]	77.73

30 -year levelized value	(Cents/kW h)	7.8

c) The marginal value used in the 2016 DSM plan is based on the 2015 export price forecast, which includes a premium associated with the sale of long term dependable energy and the value of capacity. As noted in the response to Coalition/MH I-132i, Manitoba Hydro is currently in the process of updating the generation component of the marginal values based on the export price forecast used in the MH16 Update.

8.5.1 Marginal Cost Consideration

The current .95 to 1.05 target level established relates to the evaluation of RCCs relative to Manitoba Hydro embedded COS. Manitoba Hydro believes that ratemaking and rate design must consider a number of relevant issues in addition to embedded cost; differences between marginal cost and financial embedded cost may be used as a framework for evaluation of RCC's and the bounds established in a ZOR.

It is generally recognized that efficient price signals are those which are related to relevant marginal cost. While this theoretical standard for utility price setting is rarely strictly adhered to, marginal costs and concepts may be a consideration in both cost of service and rate setting. For Manitoba Hydro, with significant fixed hydraulic investment and export revenue, that potential is much more pronounced than most utilities, as a result of its substantial heritage plants significantly below marginal cost as well as export revenues which are used to further reduce embedded costs recovered from customers.

A simplified marginal cost evaluation by class is provided in **Figure 8.14**. For comparison purposes the marginal cost by class flowing from the 2008 analysis as well and embedded cost RCC flowing from PCOSS18 is provided.

Figure 8.14 Marginal Cost Evaluation

	Levelized Marginal Value (¢/kWh)[4]				Avg Rev			PCOSS18
	Gen	Trans	Dist	Total	¢/kWh	Rev/Cost	2008 MC[5]	RCC
Residential	6.34	0.56	0.87	7.77	8.00	103.0%	72.8%	94.8%
GSS ND	6.34	0.56	0.87	7.77	8.60	110.6%	79.8%	112.5%
GSS D	6.34	0.56	0.87	7.77	6.85	88.1%	65.7%	101.0%
GSM	6.34	0.56	0.87	7.77	5.98	77.0%	59.3%	98.3%
GSL 0-30	6.34	0.56	0.87	7.77	5.14	66.1%	50.6%	99.1%
GSL 30-100	6.34	0.56		6.90	4.43	64.3%	46.7%	109.3%
GSL >100	6.34	0.56		6.90	4.01	58.1%	46.7%	108.6%

[4] 7.77 cents/KWh is the levelized marginal value used in the 2016 DSM Plan
[5] Exhibit 68, 2008 GRA

111

Manitoba Hydro
P.O. Box 815 • Winnipeg Manitoba Canada • R3C 2P4
Street Location for DELIVERY: 22nd floor - 360 Portage Avenue
Telephone / N° de téléphone : (204) 360-3946 • Fax / N° de télécopieur : (204) 360-6147
pjramage@hydro.mb.ca

February 5, 2016

Mr. K. Simonsen
The Public Utilities Board
400 - 330 Portage Avenue
WINNIPEG, Manitoba
R3C 0C4

Dear Mr. Simonsen:

RE: MANITOBA HYDRO COST OF SERVICE REVIEW

Manitoba Hydro filed materials to facilitate review of its Cost of Service Study ("COSS") methodology on December 4, 2015. On December 8, 2015, the Public Utilities Board ("PUB") directed Manitoba Hydro file additional materials, identified in the PUB's August 22, 2014 correspondence as Minimum Filing Requirements (MFRs), and requested Intervenors of past record provide comments regarding possible additional MFRs. Intervenors of past record, including the Consumers Association of Canada (Manitoba) and Winnipeg Harvest ("COALITION"), the City of Winnipeg ("COW") and the Manitoba Industrial Power Users Group ("MIPUG") each provided comments regarding additional MFRs. Manitoba Hydro filed materials in response to the PUB's direction regarding MFRs on December 18, 2015.

On January 22, 2016, the PUB distributed process directions regarding "Manitoba Hydro's Cost of Service Study Methodology Review Application and Rate Related Matters". The January 22, 2016 process directions included:

- A determination that in addition to Cost of Service matters ("COS"), the PUB would also be considering rate related matters raised in MIPUG's COS MFR submission including rate rebalancing, rate design matters and the review of terms and conditions, including service extension policies;
- Direction that Manitoba Hydro respond to COALITION and MIPUG proposed MFRs by February 5, 2016;
- Advice that the PUB had retained the law firm Hill Sokalski Walsh Olson to assist the PUB in understanding the views and position of General Service Small and Medium customers; and
- Advice that a "non-evidentiary Pre Hearing Conference" will be held Friday, February 12, 2016 with the expectation that 20 minute presentations will be made by Manitoba Hydro and Intervenors and that technical experts should be on hand to deal with issues related to the scope of the hearing.

Manitoba Hydro believes it useful to provide comments prior to the Pre Hearing Conference both with respect to the scope of the hearing and the current initiatives underway between Manitoba Hydro, the PUB and interveners as a result of the direction provided in Order 73/15.

Manitoba Hydro anticipates filing its next General Rate Application ("GRA") before the end of 2016 for rates effective April 1, 2017. In order to complete the review in a timely manner in advance of the next GRA, it is important to focus the scope of this process, and take into consideration the priorities and direction set by the PUB in Order 73/15 with regard to issues of Bill Affordability and other matters, and the direction on conservation rates provided by the Province of Manitoba in its policy paper "Manitoba's Climate Change and Green Economy Action Plan" released in December 2015 .

Manitoba Hydro has assessed these matters and provides its comments in this letter.

Application vs. Review

Manitoba Hydro notes that the PUB has referenced Manitoba Hydro's filing as an "Application". Manitoba Hydro believes there is significance in the term "application" which has potential to impact the PUB's flexibility regarding the review process, the outcome of the review and its ability to address desired changes to the COS in the future.

The PUB's authority with respect to Manitoba Hydro relates to rate approval. Manitoba Hydro must file an application when seeking a change in rates and the PUB's mandate is to approve, by order, rate changes as it considers reasonable. The PUB has broad discretion as to how it exercises its rate approval function. As noted by the PUB itself in its submission to the Manitoba Court of Appeal regarding use of the COSS when exercising its rate approval function:

> *45. There are no specific legislative requirements imposed on the Board which direct it to carry out this duty by any prescribed formulae. There are no prescribed accounting requirements or principles. There are no prescribed cost allocation principles. The Board has complete discretion over the methodology to be employed in any Hydro rate application.*
> *46. Any judicial review, leading to the creation of guidelines which serve to impose court-directed limitations on the Board, would be contrary to the words and the purpose of the legislation granting the Board the power to review and approve Hydro rates.*[1]

The Court of Appeal fully endorsed the PUB's position[2] as did Manitoba Hydro. The COSS is not a document that requires "approval" and characterizing it as such risks unnecessarily constraining the PUB's discretion and flexibility to respond to the constantly evolving environment in which the utility and regulator operate. The Court of Appeal confirmed the PUB is not restricted by legislation as to how it uses the COSS. The COSS is similar to Manitoba Hydro documents reviewed in the course of a GRA like the Integrated Financial Forecast – it informs the PUB, but does not direct rate approvals. The PUB may ask that alternative scenarios be run, but Manitoba Hydro does not apply for approval of the IFF nor does the PUB issue

[1] Brief of Argument of The Public Utilities Board, paras 45 & 46 filed in response to MIPUG's Motion Seeking Leave to Appeal in Consumers' Association of Canada (Man) Inc et al. v. Manitoba Hydro Electric Board, 2005 MBCA 55

[2] Consumers' Association of Canada (Man) Inc et al. v. Manitoba Hydro Electric Board, 2005 MBCA 55 at para 62

orders approving alternative versions of the IFF.

Manitoba Hydro recommends that the PUB consider this a review (but not an "application") that results in the PUB providing its perspectives and findings regarding Manitoba Hydro's COS for future use in GRAs.

Proposed Process and Scope of the COS Methodology Review

The COSS Methodology Review requires the review of a number of highly technical, complex and inter-related assumptions within the cost study. Given the nature of this subject matter, such a review does not lend itself well to the traditional discovery processes of filing and responding to written information requests, or the sequential examination and cross examination of witnesses. Manitoba Hydro welcomes the opportunity to suggest an alternative process in order to more effectively and efficiently communicate COS concepts and to arrive at the most appropriate outcome for all parties involved.

In recognition of the specialized technical nature of COS subject matter, Manitoba Hydro embarked on a stakeholder engagement process in the latter half of 2014. In Manitoba Hydro's view, this process was successful in re-familiarizing intervener representatives and their experts to Manitoba Hydro's COSS and the issues and alternatives that could be considered in a future public review.

Manitoba Hydro recommends an approach for this current review process which builds on the work undertaken during stakeholder meetings in the fall of 2014. Manitoba Hydro proposes that the public review be conducted by way of technical workshops where an interactive exchange of questions and ideas is facilitated by an independent PUB-appointed facilitator. These workshops would include the PUB panel members and be attended by representatives and experts from each participating party.

The workshops would focus on specific topic areas and would be structured to enable all parties to fully understand and evaluate each other's positions, and would also enable the PUB Panel members to directly pose questions to all parties' representatives and technical experts. The discussions in these workshops would be transcribed.

Instead of written information requests, Manitoba Hydro recommends that additional information that may be required would be identified by the PUB-appointed facilitator in the course of the workshop and a list of undertakings of Manitoba Hydro and/or other parties would be prepared. The undertakings responses would be distributed to all parties within a given period of time after the conclusion of the workshop.

Manitoba Hydro has provided a draft schedule of this proposed process as Attachment 1 to this letter. After the issuance of a procedural order setting the scope of the review, Manitoba Hydro suggests that a Process Conference be held to enable the Corporation and interveners to come to consensus on the MFRs to be provided by parties.

The draft schedule identifies a series of three Technical Workshops, as described below.

The first would have Manitoba Hydro present its COSS and all parties in attendance would give participating parties the opportunity to ask questions of Manitoba Hydro's staff and external consultant on subject matter within the agreed upon scope of the review process. During that workshop, there may be questions posed or modeling scenarios requested by the participants. The PUB-appointed facilitator would assist in defining the undertakings to be requested of Manitoba Hydro, and the Corporation would have a pre-determined time period after the conclusion of the Technical Workshop to prepare responses and distribute them to all parties.

Once Manitoba Hydro has provided its completed undertakings, the interveners would be required to file their evidence with all parties. A second Technical Workshop would be scheduled to facilitate the examination of the interveners' evidence and COSS proposals. The PUB-appointed facilitator would also assist in defining the undertakings to be requested of interveners, and interveners would have a pre-determined time period after the conclusion of the Technical Workshop to prepare responses and distribute them to all parties.

The third Technical Workshop would be a facilitator-led discussion to record parties' positions on issues, identify areas of consensus amongst parties, and identify topic areas that remain in dispute. The PUB-appointed facilitator would then draft a public report on the positions and state of consensus or dispute with regards to the COSS. This report would be provided to the PUB Panel members and all participating parties.

The process would then provide interveners the opportunity to provide final written submissions to the PUB on the subject matter, and enable them to advocate for positions on topic areas that remain in dispute. Following those written submissions, Manitoba Hydro would provide its final written submission to the PUB.

The PUB Panel would then be in a position to assess the evidence and respective positions provided throughout the review process and provide its findings and direction in advance of Manitoba Hydro's next GRA.

Issues

In its December 4, 2015 submission to the PUB, Manitoba Hydro provided its perspectives on the COSS and included reports prepared by its expert, Christensen and Associates. While those reports represent a wide and comprehensive review of Manitoba Hydro's COSS, it is important to focus the public review of the COSS to the critical topic areas that carry the greatest overall impact in terms of the allocation of costs to customer classes.

As noted above, Manitoba Hydro anticipates filing its GRA before the end of 2016 for rates effective April 1, 2017. In Order 73/15, the PUB indicated that it wished to review the Corporation's COSS in advance of the next GRA. In order for the PUB to complete the review in advance of the next GRA, it is important to focus the scope of this process to the most critical COS matters that have the potential to materially impact Revenue Cost Coverage ratios.

Approximately 75% of Manitoba Hydro's $1.7 billion Revenue Requirement (as identified in PCOSS14) is related to Generation and Transmission costs. The allocation of those costs affects all customer classes. The treatment of cost allocation to the Export Class and the resulting return of Net Export Revenues to domestic customer classes is a critical issue in this context. The cost allocation treatment with respect to those issues should be the critical focus of this review, and could be undertaken in a reasonable timeline in advance of the next GRA. The review of these matters would leverage the efforts undertaken by Manitoba Hydro and interested stakeholders in the COS stakeholder engagement in the fall of 2014.

Rate Design and Rate Rebalancing Matters

In its letter of January 22nd, the PUB indicated its interest in considering various rate design matters, such as the respective levels of Basic Monthly Charges, energy charges and demand charges, and the rate design considerations for Time-of-Use Rates for General Service Large customers and conservation rates for residential class customers.

In Order 73/15, the PUB directed Manitoba Hydro to lead a collaborative process to develop a bill affordability program harmonized with Manitoba Hydro's other programs supporting low income ratepayers. In addition, Manitoba Hydro has incorporated plans for developing a conservation rate design for residential customers, as part of its future PowerSmart programming initiatives. In December 2015, the Province of Manitoba announced "Manitoba's Climate Change and Green Economy Action Plan" which requires Manitoba Hydro to develop a conservation rate structure to be brought before the PUB in its next General Rate Application.

Manitoba Hydro is currently working on both above noted initiatives. With respect to residential conservation rates, Manitoba Hydro is currently retaining an expert to prepare analysis and alternative rate options for consideration. These alternative rate option scenarios would consider appropriate levels for the Basic Monthly Charge, the level and size of the first energy block, and the level and degree of inversion for the run-off block.

Manitoba Hydro expects to engage stakeholders in the discussion of these alternative rate options later in 2016, and prior to the finalization of its next GRA filing before the PUB. Given the potential intersection of issues with respect to customer bill affordability, Manitoba Hydro expects to take advantage of its current stakeholder engagement with parties on bill affordability programming and to have those parties provide input and feedback on the various rate design alternatives that may be prepared. Upon receipt of that stakeholder feedback, Manitoba Hydro would finalize its residential conservation rate design proposal and upon direction of the Manitoba Hydro-Electric Board, incorporate that proposal into its upcoming GRA.

Manitoba Hydro believes that this order of sequence is appropriate in light of past direction of the PUB (for bill affordability programming) and the current policy impetus to develop and introduce residential conservation rates to be examined by the PUB in the next General Rate Application.

With respect to Time-of-Use rate design for the General Service Large customers served at voltage levels greater than 30 kV, Manitoba Hydro is of the view that such a proposal could be addressed at the next GRA. Should the PUB wish to examine the TOU concept in this process, it should only do so if there is sufficient time and resources available in a manner that would not detract or negatively impact the review of the COSS.

In Manitoba Hydro's view rate rebalancing is best dealt with subsequent to the review of COS, taking into account other competing factors and policy considerations in the context of a rate setting proceeding.

Terms and Conditions & Service Extension

Manitoba Hydro can provide information regarding its terms and conditions of service for the provision of power, however *The Manitoba Hydro Act* clearly places jurisdiction over the terms and conditions with the Manitoba Hydro Electric Board, which jurisdiction is, with respect to certain aspect of the terms and conditions, subject to Lieutenant Governor in Council approval:

> **Regulations as to supply of power**
> 28(1) The board may, by regulation, prescribe
> (a) the terms, and conditions upon and subject to which the corporation will supply power to the users of the power supplied by it;
> (b) the standards governing the construction, installation, maintenance, repair, extension, alteration, and use of electric wiring and related facilities using or intended to use power supplied by the corporation;
> (c) such other conditions relating to the supply of power to users of that power, not inconsistent with this Act, as the corporation deems necessary for the proper carrying out of this Act and for the efficient administration thereof.
>
> **Regulations**
> 52 For the purpose of carrying out the provisions of this Act according to their intent, the board, with the approval of the Lieutenant Governor in Council, may make such regulations and orders as are ancillary thereto and are not inconsistent therewith; and every regulation or order made under, and in accordance with the authority granted by, this section has the force of law; and, without restricting the generality of the foregoing, the board, with the approval of the Lieutenant Governor in Council, may make regulations and orders:
> (a) requiring the owner of any power plant or works to furnish to the board any information required by the board regarding
> (i) his plant and works including the capacity, output, cost, and use thereof;
> (ii) his assets, liabilities, revenues, expenses, and operations;
> (iii) the supply of power by him to other persons including particulars of quantities, prices, terms, conditions, points of delivery and use;
> (b) requiring any person to furnish to the board information regarding the supply of power to him, including particulars of quantities, prices, terms, conditions, points of delivery, use, and by whom supplied;
> (c) providing for the entry upon, and inspection of property, plant and works including the making of inventories and valuations thereof, the examination of books, accounts, records, and documents relating thereto, and generally the obtaining of information in connection therewith;
> (d) providing for the discontinuance of the supply of power to any customer who is in default in payment of any account for power or any monthly charge levied under the on-meter efficiency improvements

> program under *The Energy Savings Act*, providing for the removal of the meters, wires, facilities and equipment of the corporation from the premises of the customer and providing for the allocation of, or exemption from, liability for losses, costs, damages or expenses resulting from such discontinuance or removal;
>
> (e) providing for the allocation of, or exemption from, liability for any loss, costs, damages or expenses incurred by a customer or any other person resulting from any fluctuation, interruption, reduction or failure in the supply of power;
>
> but no regulation or order made under this section shall relieve the corporation from liability for negligent acts or omissions.

Had the legislature intended terms and conditions be subject to PUB approval, it would not have given Manitoba Hydro the power to pass regulations. Regulations are a form of legislation and can only be amended in accordance with *The Statutes and Regulations Act.* The PUB does not possess the jurisdiction to establish or change Manitoba Hydro's regulations.

Manitoba Hydro can also provide the PUB with information regarding its service extension practices to such extent they are related to the COS review. Manitoba Hydro notes, however that *The Manitoba Hydro Act* clearly places jurisdiction over the terms and conditions upon which service extensions will be made solely with Manitoba Hydro:

> **Terms and conditions of service extensions**
>
> 49.1 The extension or enhancement of the supply of power by the corporation to any customer shall be on terms and conditions, which may include a contribution to, or payment for, capital expenditures, acceptable to the corporation.

Unlike s.39 (2) which makes the Corporation's authority to fix the price for power subject to PUB approval, s. 49.1 contains no such requirement with respect to obtaining contributions related to extending or enhancing the system in order to allow for the supply of power to commence. There exist two distinct concepts – s. 49.1 deals with the terms and contributions collected to recover the cost of connecting to the system in order to be in a position to receive power; s. 39 deals with the price payable for the power itself. Capital contributions collected under the service extension policy deal with incremental costs that a new customer/load imposes on the system and are not part of the price for power regulated by the PUB.

Minimum Filing Requirements

The PUB directed Manitoba Hydro respond to a number of additional filing requirements proposed by the interveners COALITION and MIPUG, by February 5, 2016. In addition Manitoba Hydro was directed to develop a rudimentary working model of PCOSS14 that could be provided to Intervenors. Manitoba Hydro had expected that MFRs would be set after the scope of the review was determined at the Pre-Hearing Conference, and that it would be able to comment on same, both in terms of relevance and its ability to prepare and/or supply within the timeframes of the review process.

Manitoba Hydro remains concerned that providing a COS model and planning and conducting training sessions will consume a substantial amount of time, particularly to analyze and understand changes made to the model by other parties and their potential impacts. Instead, Manitoba Hydro proposes that having the Corporation undertake to model alternative assumptions and then present the results as part of the COS review would be a more efficient approach.

With respect to the information requested in MIPUG's MFRs, much of what has been requested is not information Manitoba Hydro has available in a form suitable for immediate filing. The MFRs proposed by MIPUG require the assembly of data, analysis, review and internal approval prior to being submitted as evidence in a public forum. As such, it was not possible to accomplish this by February 5, 2016. Manitoba Hydro has compiled some of the information requested that is readily available and has included this information as Attachments to this letter. As the scope of the COS review has not yet been finalized, Manitoba Hydro is not in a position to assess whether these documents fall within the scope.

With respect to COALITION's request for a copy of the Diesel Settlement Agreement, Manitoba Hydro can advise that it does not have an executed copy in its possession and while Manitoba Hydro has no objection to the release of the document, there remain possible legal issues if the Corporation were to voluntarily file an unsigned copy. If the PUB believes this an important document in the COSS review it may be necessary to compel MKO to produce the fully executed agreement or alternatively Manitoba Hydro to provide the partially signed version it has in its possession.

Intervener Costs

Manitoba Hydro is concerned with the PUB's stated intention that it does not intend to consider the sufficiency of financial resources as a criterion in awarding intervener costs. Given that ratepayers fund intervener cost awards, Manitoba Hydro would appreciate the opportunity to understand the rationale behind the PUB's decision to waive its established Rules of Practice and Procedure in the context of the COSS Review.

General Service Small and Medium Class Representation

In this process the PUB has appointed legal counsel to represent the General Service Small and Medium Class. Manitoba Hydro recognizes that these classes have not been formally represented in PUB processes for a number of years. Manitoba Hydro views representation of all customer classes as a laudable objective of the regulatory process but has concerns whether the appointment of counsel, without a client to provide class perspective or to instruct counsel, achieves this objective. Manitoba Hydro would appreciate the opportunity to gain a better understanding of how representation will be achieved.

Conclusion

Manitoba Hydro recognizes that a number of parties, including the utility itself, believe a review of the COSS is overdue. High priority work such as the NFAT and GRAs have necessitated the deferral of the review of COS. This is an important topic for Manitoba Hydro as fair allocation of costs clearly impacts the Corporation's mandate to provide service in an efficient manner. Manitoba Hydro sees it important that the COS review focus on the critical topic areas that carry the greatest overall impact in terms of the allocation of costs to customer classes.

Manitoba Hydro appreciates the PUB's recognition of the advantages of addressing this subject matter through an alternative review process and encourages the PUB to give consideration to the process proposed herein.

Yours truly,

MANITOBA HYDRO LAW DIVISION
Per:

PATRICIA J. RAMAGE
Barrister and Solicitor
PJR/
cc: Bob Peters

Proposed Cost of Service Review Process & Timelines		
Item	**Purpose**	**Due Dates**
Pre-Hearing Conference	Discuss Issues in Scope, Proposed Interventions and Process Timelines Present: MH, Interveners, PUB Panel and Staff (All Parties)	Friday, February 12, 2016
Receipt of PUB Procedural Order		Wednesday, February 24, 2016
Process Conference	Develop List of MFRs based on the established Scope. Present: MH, Interveners and PUB Staff.	Friday, March 04, 2016
MH to File MFRs		Wednesday, March 30, 2016
Technical Workshop #1 (MH Model and Assumptions)	MH presents its COSS, assumptions and cost treatments, and respond to questions from All Parties. Present: All Parties.	April 11-12, 2016
MH to File Responses to Undertakings from Technical Workshop #1		Tuesday, May 03, 2016
Interveners to File COS Proposals	Interveners to file their COSS proposals and assumptions	Tuesday, May 17, 2016
Technical Workshop #2 (Interveners Models and Assumptions)	Intervenors present their COSS proposals and assumptions, and respond to questions from All Parties. Present: All Parties	May 24-25, 2016
Interveners to File Responses to Undertakings from Technical Workshop #2		Wednesday, June 15, 2016
Technical Workshop #3 (Facilitator-led Discussion)	Facilitator-led Concurrent Evidence Session to Record Parties' Positions on Issues, Identify Areas of Consensus and Dispute. Present: All Parties	Wednesday, June 22, 2016
Facilitator Issues Draft Report to MH and Interveners	The Report Identifies Areas of Consensus and Areas of Dispute that Require PUB Resolution	Wednesday, July 13, 2016
MH and Interveners to Provide Comments on Draft Report		Wednesday, July 27, 2016
Facilitator Issues Final Report to PUB		Wednesday, August 03, 2016
Interveners Provide Written Final Submissions	Final Written Submissions Outlining Interveners Positions.	Wednesday, August 10, 2016
MH Provide Written Final Reply Submission	Final Written Reply Submission Outlining MH Positions.	Wednesday, August 17, 2016
PUB Issues Findings and Directions	PUB Assess Written Submission and Issue Findings	August-September 2016

Noted Dates:
Louis Riel Day: Monday, February 15, 2015
Good Friday: Friday, March 25, 2016
Victoria Day: Monday, May 23, 2016
Canada Day: Friday, July 1, 2016
Civic Holiday: Monday, August 1, 2016
Labour Day: Monday, September 5, 2016
Thanksgiving: Monday, October 10, 2016

Attachments:

- MIPUG MFR 11, which requests the resumes for all consultants/external contributors who participated in the preparation of Manitoba Hydro's study and Christensen Associates review;
- PUB MFR 16, Information Requests on the Rate Related Matters (as identified in the PUB's letter of January 22, 2016) that were filed during the last three GRAs;
- PUB MFR 17, Documentation provided at the 2014 stakeholder consultation sessions with respect to Cost of Service.

Rate-Related Matters

The Board accepts Manitoba Hydro's submission that of the rate-related matters identified in the Board's January 22, 2016 letter, rate rebalancing, time-of-use rates, and conservation rates should be excluded from the scope of this hearing and be dealt with at the next General Rate Application. The outcome of this Cost of Service Methodology Review will permit Manitoba Hydro to address any rate rebalancing requirements at such a hearing. The Board is further of the view that the existing proposal for industrial Time-of-Use rates is best addressed at the same time as any proposal for conservation rates that Manitoba Hydro is required to advance pursuant to Provincial policy. To the extent the Board's January 22, 2016 letter constitutes a determination that these issues would be in scope, the Board hereby reviews and varies that determination.

However, the Board intends to examine the components of the basic monthly charge, and the split between energy charges and demand charges as part of this hearing, as these relates directly to cost of service study issues. The Board further intends to review Manitoba Hydro's Terms and Conditions of Service and Service Extension Policy, which Manitoba Hydro has agreed to file.

Hearing Process

The Board finds merit in a departure from the usual hearing process involving two rounds of written Information Requests followed by sequential oral testimony subject to cross-examination. However, the Board does not consider it feasible to dispense with a written discovery process entirely and considers it important that cross-examination be permitted on key issues. The Board has accordingly determined the following process for the Cost of Service Methodology Review:

1. Manitoba Hydro is to complete the filing of outstanding Minimum Filing Requirements related to the issues now determined to be in-scope.

2. The Board and Interveners will be able to issue one round of written Information Requests to Manitoba Hydro.

112

Wondering about your energy options for space heating?

The chart below shows an example of space heating costs that are based on an average single family residence, at rates in effect November 1, 2017.

1. Consult the charts to identify the costs of your current space heating system.

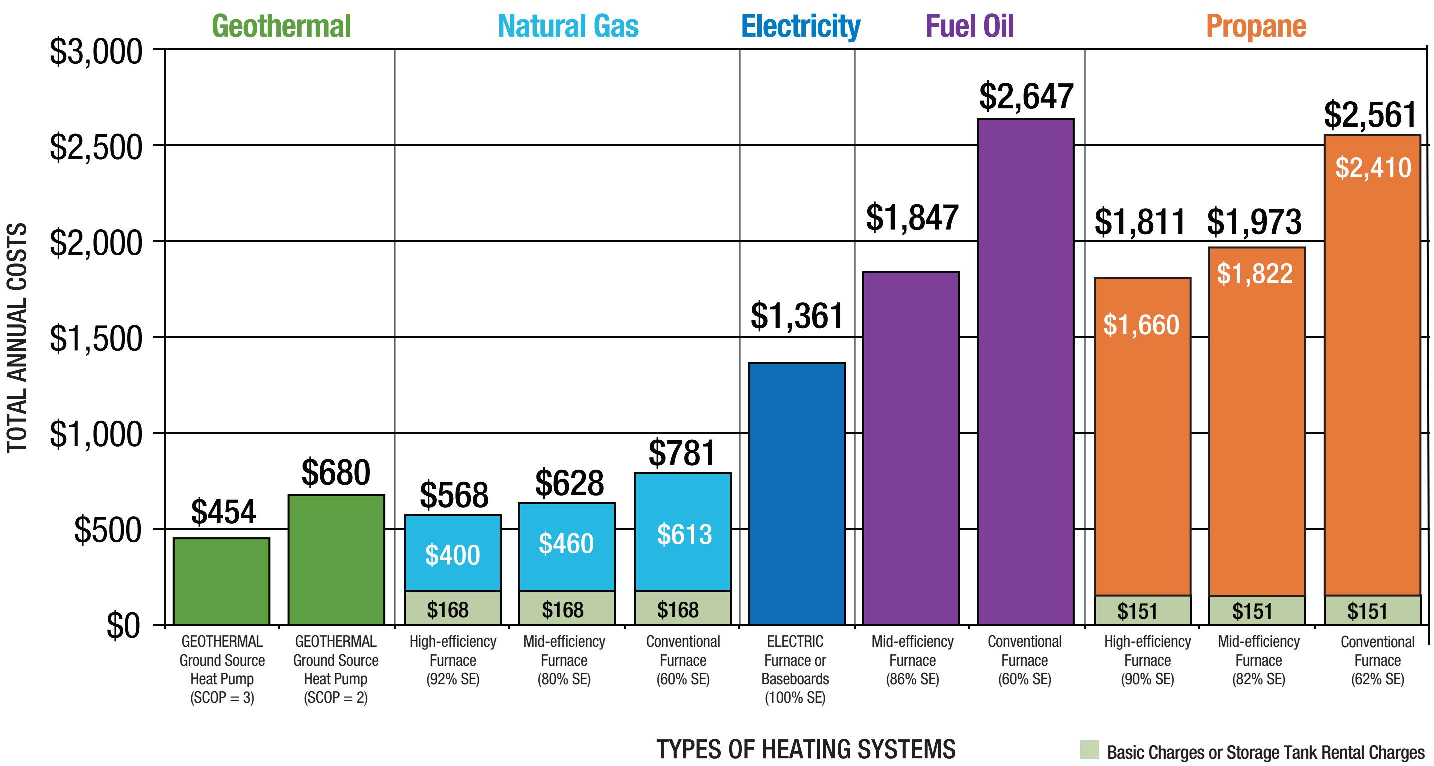
2. Review the annual energy costs of other systems to see how your costs compare.

3. Consult the accompanying notes on pages 2, 3 and 4 for guidance if you are thinking of switching space heating systems or building a new home.

4. Visit **hydro.mb.ca/heating** and use the online calculator to get a customized estimate for your specific home's annual and total lifetime space heating costs based on different heating systems and energy sources.

Annual Space Heating Costs

(Average single family residence)



Energy rates

as of November 1, 2017.

Natural gas: **$0.2293**/cubic metre

Electricity: **$0.08196**/kilowatt-hour

Fuel oil: **$1.023**/litre

Propane: **$0.638**/litre

Basic monthly charge for natural gas is **$14** (**$168** per year)

Annual propane tank rental: **$151**

Space heating annual costs shown in the chart above are based on "point-in-time" prices as noted.

The annual space heating costs presented in the chart exclude the cost of converting to a different heating system, which may be significant.

See page 3 if you are thinking of changing your heating system.

Depending on your supplier, propane and fuel oil prices can fluctuate on a daily basis.

Manitoba Hydro

Annual cost estimates

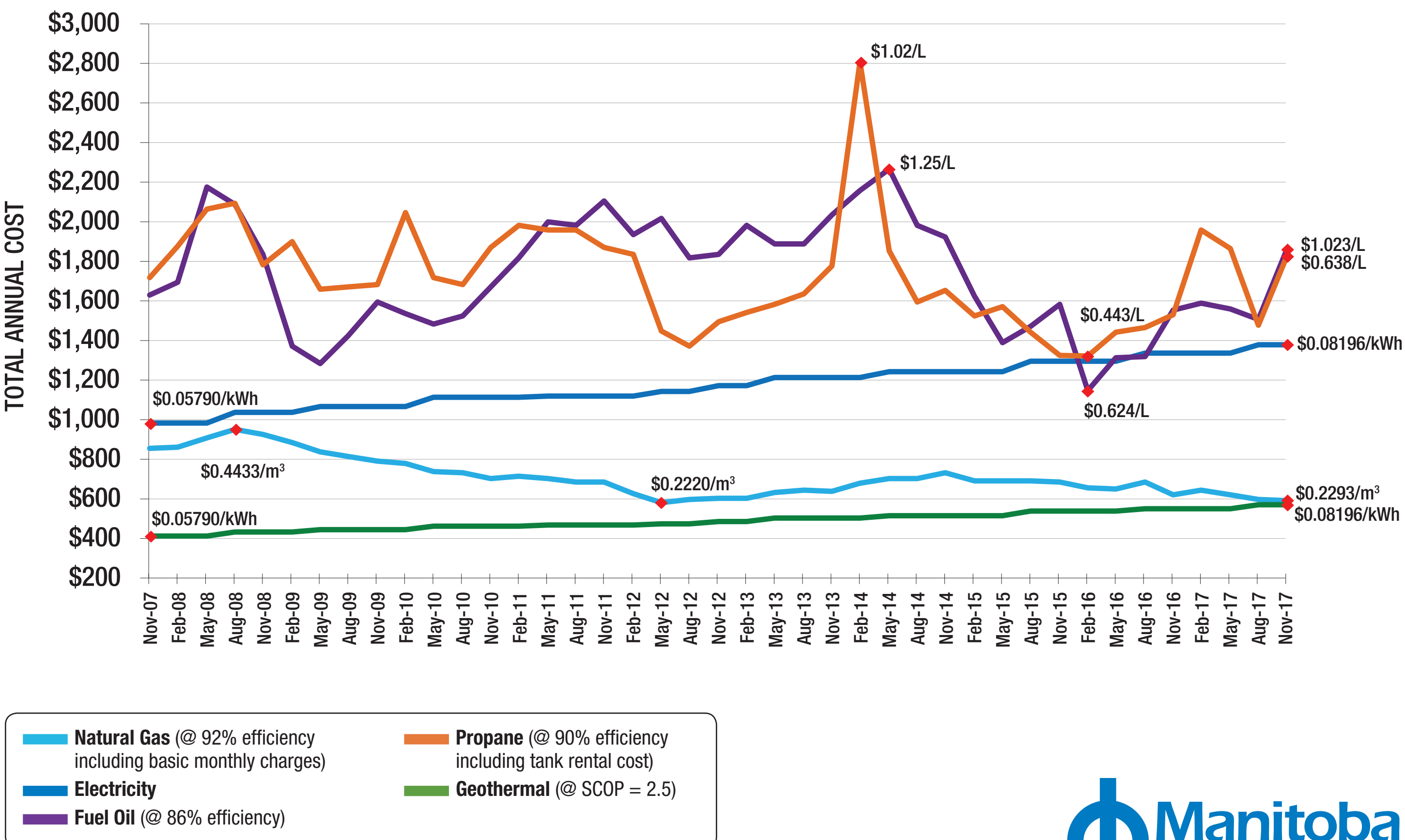
The space heating costs shown in the charts are based on the amount of energy required to heat the average single-detached home that is served by Manitoba Hydro. The average single-detached home on Manitoba Hydro's system requires approximately 60 Gigajoules (output) of energy for space heating. Your space heating costs may differ due to a variety of factors, such as weather, heating equipment, insulation levels, air tightness, lifestyle, and energy rates paid. If you think your space heating usage is higher or lower than the average shown here, please factor up or down the operating costs of the various heating systems shown in the chart. The costs shown are relative, illustrative and for general comparison purposes only.

The charts on the first page present annual costs as if all energy rates remained fixed for the coming year at the rates in effect on November 1, 2017.

Your actual annual energy costs will vary. Natural gas rates change four times per year, electricity rates typically change on an annual basis and depending on your supplier, propane and oil rates can change daily. With Manitoba Hydro's Quarterly Rate Service, the price you pay for Primary Gas is the same price we pay for the gas in the marketplace. This rate changes every 3 months and is currently $0.0831 per cubic metre. If you buy Primary Gas on a Fixed Rate Service contract from Manitoba Hydro or a Gas Broker, you will continue to pay Manitoba Hydro for Supplemental Gas as well as transportation and distribution charges. The figure of $0.2293 per cubic metre of natural gas that we've used in the charts is known as a "re-bundled" effective rate. It includes charges for Primary and Supplemental gas, as well as for transportation and distribution of the gas on Manitoba Hydro's Quarterly Rate Service.

The chart below shows a 10 year history of annual operating costs of various energy sources and space heating systems. The chart also shows the minimum and maximum energy prices for a given point in time by energy source over the 10 year period. The energy prices shown are provided as reference points to show the relationship between the energy price at a given time and the annual operating costs of a specific heating system.

Example Space Heating 10-year Cost History



Key points if you are thinking of changing heating systems

Is it economically feasible?

Note that the costs of switching to another system to heat your home may be economically feasible only if your current system is at or near the end of its useful life, or if you are building a new home. Be sure to obtain quotations from at least three reputable heating contractors before you make your decision.

Size of existing electrical service

Your electrical system may need to be upgraded if you want it to carry a space heating load.

Depending on the capacity of the electrical appliances and equipment currently installed, and the size of your home, the Manitoba Electrical Code will allow a maximum of 8 to 10 kilowatts of electric heating on a standard 100-amp service. Most homes will need more than this.

Increasing the size of an electrical service usually involves changing your electrical panel or installing an additional one. An electrician should perform an electrical code load calculation to advise whether your existing service is adequate to serve the heating equipment required to heat your home.

Other gas appliances

If you have other appliances in your home like a range, clothes dryer, fireplace, or swimming pool heater, switching to an all-electric system may be quite costly.

Flue gas venting

When gas is burned, flue gases are produced which primarily contain carbon dioxide and water vapour which are not harmful to people. However, flue gases can also contain trace amounts of carbon monoxide and other gases that can present a health hazard. High-efficiency gas furnaces will not use the existing chimney to vent (remove) flue gases from the home. Instead they will be vented via approved plastic piping through the home's side wall or roof.

Chimney ventilation

With a conventional gas furnace, warm moist air continuously exits the house through the chimney. This draws cold and dry replacement air into the house through cracks in walls and around windows and doors. This uncontrolled ventilation dehumidifies your home in winter, but consumes heating energy.

Reducing or eliminating this chimney ventilation can save energy but may also increase unwanted humidity levels and change the way that air leaks into and out of your home. Homes usually become slightly more positively pressurized.

Converting to a high efficiency gas furnace or to electric heat will reduce the uncontrolled ventilation through the chimney. Along with upgrading to a high efficiency gas furnace, if you remove your existing conventional gas water heater at the same time and install a power-vent gas or electric water heater you will completely eliminate the uncontrolled chimney ventilation.

When upgrading your space heating system to a high efficiency gas furnace you don't have to change your water heater. In many cases the existing chimney will be sufficient to continue to operate your conventional gas water heater, in some cases you may need to install a chimney liner. If you are unable to upgrade the chimney then a power-vent gas water heater may be an option for you. Speak with a licensed and reputable heating contractor about your water heating options for your specific home.

Increase in humidity and change in air leakage patterns may cause increased condensation/icing: on interior surfaces of well-sealed windows, and anywhere warm moist air leaks out of the home such as electrical outlets, between the panes of poorly sealed windows, on door seals, in door lock mechanisms and around chimney and plumbing stacks. A very small percentage of homeowners have reported experiencing some of these issues.

There is not one solution that works in every home and for every issue. Here are some of the measures that individually or in combination can minimize or eliminate the effects of reduced chimney ventilation:

- improved weatherstripping and caulking on doors and windows and other areas of air leakage (but not on storm doors)
- seasonal window insulator kits (clear heat shrink poly over inside windows and frames)
- improved windows (preferably triple pane)
- a ventilation system which may consist of:
  - exhaust fan(s)
  - exhaust fan(s) combined with a fresh air intake
  - heat recovery ventilator (HRV)

Carbon monoxide safety

If you are burning heating oil, diesel, propane, kerosene, natural gas, wood, or coal in your home, or if you have an attached garage, we recommend that you install at least one carbon monoxide detector in your home.

The building code now requires permanently mounted carbon monoxide detectors in all new homes with fuel burning appliances or attached garages.

For further details, contact us for a copy of our brochure on "Carbon monoxide safety – Because your family comes first!".

Calculate your payback

Determining how many years it will take for a new heating system to pay for itself may help you reach a decision.

Determine the potential savings

Subtract the annual cost of the new heating system you are considering from the annual cost of your current heating system (check the charts).

The difference is approximately what you can expect to save each year, at current energy rates.

Determine the costs of the new system

Determine how much it will cost to buy and install the new system, along with any other adjustments required. Get quotations from three reputable contractors.

Factor in the cost of financing, if necessary.

Determine the payback

Divide the estimated cost of switching your system, by the estimated savings.

The result is the number of years it will take for the new heating system to pay for itself.

Explanation of technical information in the charts

- The cost of heating with propane includes a propane tank rental or lease charge of $151 per year for a typical 500 US gallon tank. This charge may not apply to all customers and may vary by propane supplier.
- The cost of space heating with natural gas includes a basic monthly charge of $14 ($168 per year).
- SE (seasonal efficiency) is defined as the total heat output delivered by the furnace during one heating season as a percentage of the total energy input to the system. SE takes into consideration not only normal operating losses but also the fact that most furnaces rarely run long enough to reach their steady-state efficiency temperature, particularly during milder weather at the beginning and end of the heating season.
- SCOP (Seasonal Coefficient of Performance) = 2 and = 3 appears in the home heating chart under geothermal closed loop heat pump. It refers to the Seasonal Coefficient of Performance of the heat pump over an entire heating season.

  SCOP is defined as the total heat output of the system during the heating season, divided by the total energy input to the system.

ENERGY RATES — in effect November 1, 2017

	Commodity charge	Heating value
Natural gas	$0.2293/cubic metre	35,310 Btu/cubic metre
Electricity	$0.08196/kilowatt-hour	3,413 Btu/kilowatt-hour
Fuel oil	$1.023/litre	36,500 Btu/litre
Propane	$0.638/litre	24,200 Btu/litre

The SCOP of a geothermal heat pump system typically ranges from 2.0 to 3.0. For reference, the SCOP of an electric baseboard heater is 1.0. The SCOP rating accounts for cycling losses, circulating fan and pump energy and auxiliary electric heating loads which are not included in the manufacturer's COP rating of the heat pump "unit". The overall system SCOP will therefore always be significantly lower than the unit COP.

The SCOP of a geothermal system can vary significantly and is highly dependent on the quality of the system design, installation, commissioning, and ongoing maintenance practices.

- Note that the natural gas energy price reflected in the charts is a bundled price that includes primary and supplemental gas, and transportation and distribution charges. For reference, one of the major components of the bundled price is the price of Primary Gas, at $0.0831 per cubic metre. Primary Gas currently comprises 92 per cent of the gas supplied (supplemental gas is 8 per cent.)
- Taxes are not included in the examples.

Manitoba Hydro

REFERENCE:

Appendix 7.2 15 Year DSM Plan Page 14; 2012/13 GRA Appendix 26; Manitoba Hydro October 6, 2016 presentation to DSM stakeholder group

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please update Manitoba Hydro's 2016 fuel switching analysis referenced at and shown in the presentation from the October 6, 2016 DSM Stakeholder meeting.
b) Please outline Manitoba Hydro's current policy and strategy relative to Fuel Choice Initiatives for the test years.
c) Similar to NFAT PUB Exhibit 58-2 pp. 92 and 93, please provide the annual residential space and water heating cost comparison between electric and gas using:
   i. High efficiency gas furnace consumption, standard efficiency gas and electric water heater consumption
   ii. Actual electric and gas billed rates (from 2002 to latest available)
   iii. Forecast electric rate increases equal to those proposed in IFF16
   iv. Two separate forecast gas rate curves:
      - CGM16 gas assumed rate increases with commodity portion of forecast gas rate assumed to follow a relevant and recent price forecast, such as AECO-NIT future prices.
      - Same as above but also accounting for the impact of the federal carbon pricing backstop system recently proposed by the Government of Canada (i.e.: rates for fuels are subject a levy equivalent to $10 per tonne of CO_2e in 2018 and increase by $10 per tonne annually to $50 per tonne in 2022).

RATIONALE FOR QUESTION:

To better understand Manitoba Hydro's test year Fuel Choice strategy, which was recommended to continue by the Board in its NFAT report. To visualize customer impacts and to understand customers' options with respect to fuel switching and a potential residential electric heat rate design.

RESPONSE:

a) Manitoba Hydro's 2016 fuel switching analysis referenced at and shown in the presentation from the October 6, 2016 DSM Stakeholder meeting is the most up to date analysis at this time.

b) Manitoba Hydro is a provider of both electricity and natural gas and therefore, a customer's heating fuel choice should be made by the customer. However, recognizing that heating costs are a significant portion of a customer's annual energy bill, Manitoba Hydro, through the fuel choice initiative, provides educational information and innovative financing to assist customers in making an informed decision. The primary objective of the fuel choice initiative is to ensure customers understand the costs (both annual operating costs and total lifetime costs) of various energy sources and heating equipment so that they can make the choice that best meets their specific needs.

   The fuel choice initiative takes a multi-faceted approach recognizing there are several stakeholders involved in or influencing the customer's fuel choice decision. The initiative targets homeowners, heating contractors, homebuilders, land developers and Realtors.

   Customers and stakeholders are provided heating education information through:

   - Manitoba Hydro's website, which includes tools such as videos, graphs and a heating cost calculator that allows customers to easily compare the costs of various energy sources and heating systems
   - social media advertisements
   - energy bill inserts
   - newspaper advertisements
   - magazine advertisements in lifestyle and renovation magazines
   - billboards in new home sub-divisions in gas available areas of rural Manitoba
   - brochures that are distributed to heating contractors, land developers, Realtors and at Manitoba Hydro's Customer Service Centres

Information sessions are also held annually with heating contractors, homebuilders, land developers and Realtors to increase understanding of heating costs in Manitoba, including what cost implications there are when selecting a specific energy source.

To aid in offsetting the capital cost of a new heating system, Manitoba Hydro offers two convenient on-bill financing programs; the Power Smart Residential Loan and Power Smart PAYS Financing. In many circumstances the customer's average monthly energy bill savings from choosing the natural gas system over an electric system offset the monthly finance fee. Marketing materials speak to the availability and benefits of these offerings.

In addition, where a natural gas service extension request is received from a large commercial customer, Manitoba Hydro works to leverage the larger commercial customer project to extend service to smaller customers along the way.

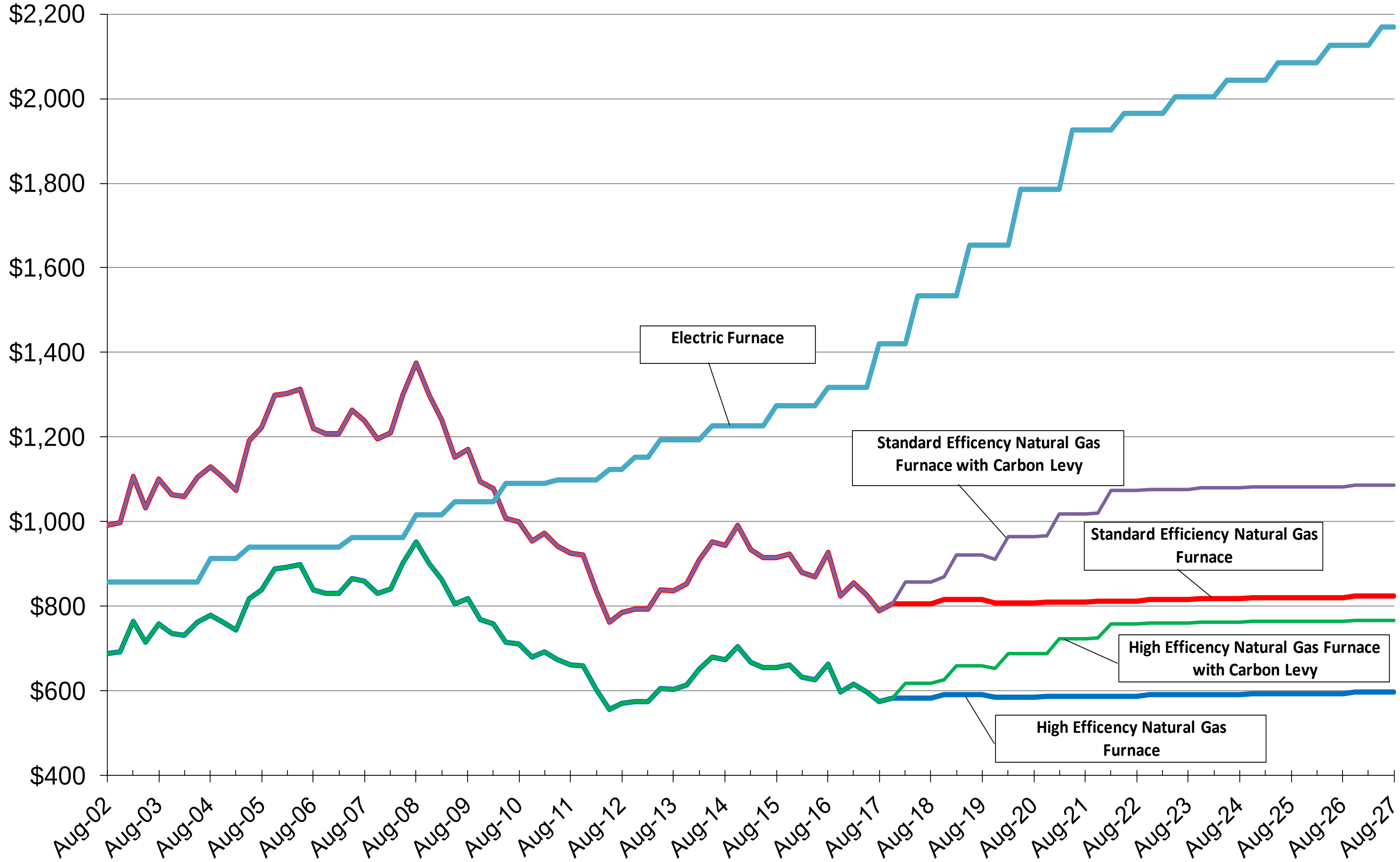
c) Manitoba Hydro has reproduced the PUB's graph below which provides annual residential space and water heating cost comparisons between natural gas and electricity.

Assumptions:

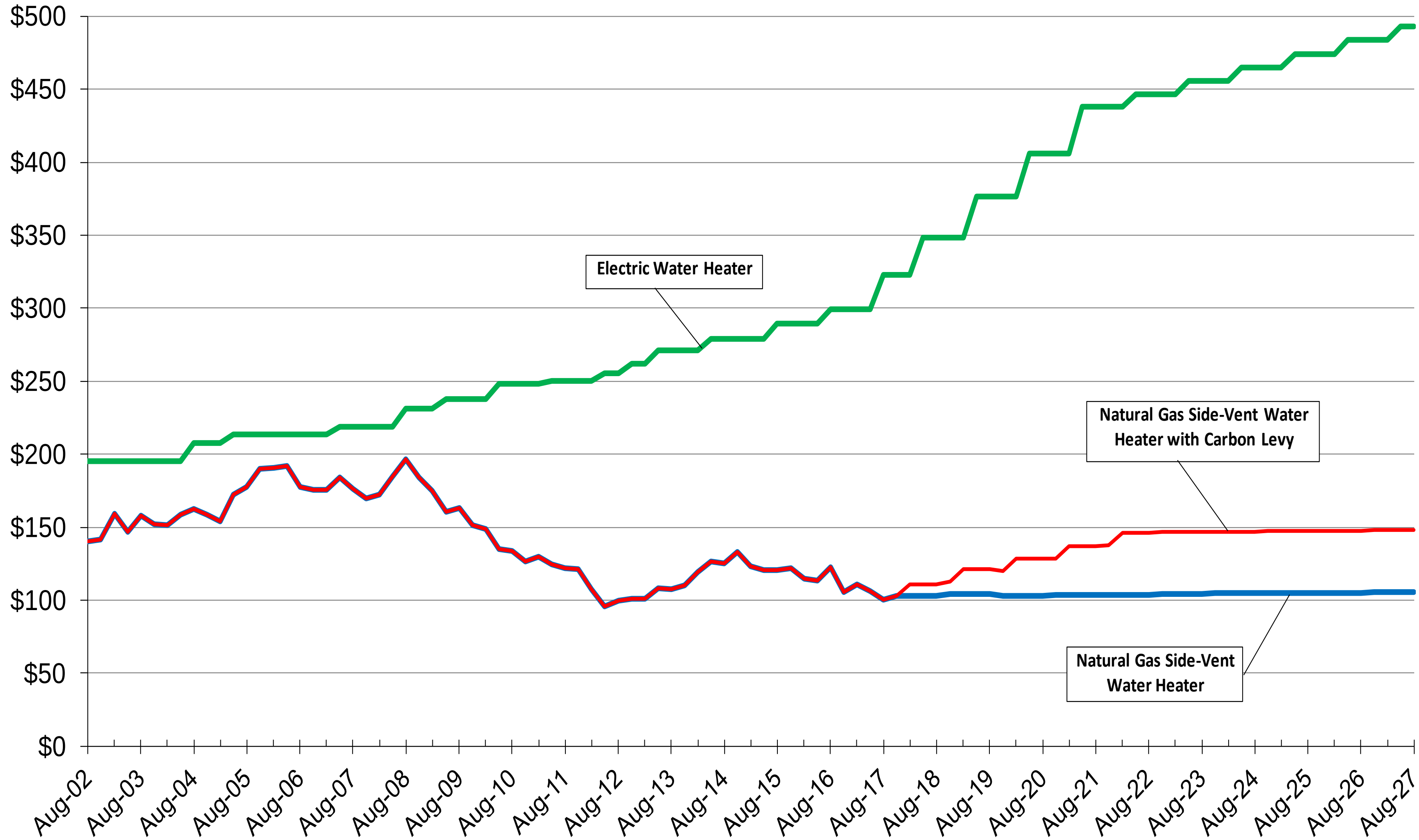
- The natural gas high efficiency furnace has an efficiency rating of 92% and an annual energy consumption of 1 742 cubic metres, the standard efficiency furnace has an efficiency rating of 60% and an annual energy consumption of 2 675 cubic metres. The annual energy consumption of the electric furnace is 16 605 kWh.
- The electric water heater is 60 gallons with a stand-by loss of 90 watts and an annual energy consumption of 3 777 kWh.
- The natural gas side-vent water heater is 50 gallons with an energy factor rating of 0.67 and an annual energy consumption of 431 cubic metres.
- Actual electric billed rates were used from August 1, 2002 until July 31, 2017.
- Forecasted electric rates were used from August 1, 2017 going forward and reflect the forecast rates included in MH16.
- Actual natural gas billed rates were used from August 1, 2002 up to October 31, 2017.

- Forecasted natural gas rates were used from November 1, 2017 forward. The non-commodity portion of the forecasted gas rates is based on CGM16. The commodity portion of natural gas rates is based upon July 28, 2017 futures market prices.
- The cost comparisons that include carbon pricing are based on the Government of Canada's $10 per tonne of CO_2e in 2018 which increases by $10 per tonne annually to $50 per tonne in 2022.

Space Heating Cost Comparison



Water Heating Cost Comparison



REFERENCE:

Appendix 9.14

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update PCOSS18 to reflect the embedded cost of service supporting the 7.9% initial rate request and separating the existing residential class into separate residential electric heating and non-heating customer sub classes.

RATIONALE FOR QUESTION:

RESPONSE:

In order to segregate the residential class into All-Electric (electric heating) and Standard (non-electric heating) subclasses, the Residential energy and demand allocators from Schedule 5.3 of Appendix 8.1 have been separated into subclasses in the table below. The estimated Demand for each of the subclasses has been derived using the updated Load Research results for 2014/15 provided in Manitoba Hydro's response to Coalition/MH II-81d.

The separation of All-Electric and Standard Residential customers does not change the aggregate subclass energies or coincident peak (CP) demands compared to those of a single Residential class, but does change the time and magnitude of the non-coincident peaks (NCP). Due to loss of load diversification, the aggregate subclass NCPs will tend to be higher compared to when all residential customers are treated as a single class.

While PCOSS18 used the average CP load factors derived from eight Load Research studies, only one Load Research study with segregated Residential results is available. The use of CP load factors from only a single year has resulted in a change in the aggregate subclass CP Demands, compared to that of the single Residential class. Since this change would not occur if segregated results were available for the full eight years, the difference in CP

Demand has been allocated between the subclasses to reconcile back to the Residential CP Demand used in PCOSS18.

Schedule 5.3 Column	**Residential Standard**	**Residential All-Electric**	**Total**
Forecast Customer	295,288	190,134	485,421
Forecast Total kWh Sales Before DSM	3,110,550,315	4,503,630,806	7,614,181,121
Forecast DSM kWh Savings	(52,278,200)	(75,691,336)	(127,969,536)
Total kWh Sales After DSM E20	3,058,272,115	4,427,939,470	7,486,211,585
Distribution Losses	208,060,516	301,241,792	509,302,308
Common Bus Losses	303,293,982	439,126,193	742,420,175
kWh Generated Adjusted E10	3,569,626,613	5,168,307,455	8,737,934,068
CP Load Factor	***64.7%***	***44.8%***	50.6%
CP @ Meter Before DSM MW	548.8	1,147.6	1,696.4
Reconcile CP Demand (1 vs 8 year Load Research)	***7.1***	***14.8***	***21.9***
Forecast DSM MW Savings	(15.4)	(32.2)	(47.6)
CP @ Meter After DSM MW	540.5	1,130.2	1,670.7
Distrib Losses MW	44.3	92.5	136.8
Common Bus Losses MW	50.6	105.8	156.3
CP @ Gen.MW D13/D14	635.3	1,328.5	1,963.9
Class Coinc. Factor	***81.3%***	***90.0%***	90.0%
Demand NCP MW@ Meter D50	664.8	1,255.8	1,920.6
Demand NCP MW@ Gen. D20	781.5	1,476.1	2,257.6

The updated Schedules 1.1, 1.2 and 1.3 below reflect the results of PCOSS18 that includes the initial 7.9% rate increase request, and segregates the Residential class into All-Electric and Standard subclasses.

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2018
Revenue Cost Coverage Analysis

SUMMARY

Customer Class	Total Cost ($000)	Class Revenue ($000)	RCC % Prior to NER	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates
Residential - Standard	**314,337**	**266,898**	**84.9%**	**58,886**	**325,784**	**103.6%**
Residential - All Electric	**519,400**	**366,132**	**70.5%**	**101,735**	**467,867**	**90.1%**
Residential - Seasonal/FRWH	**15,148**	**9,644**	**63.7%**	**1,485**	**11,129**	**73.5%**
Residential - Total	848,885	642,674	75.7%	162,107	804,781	94.8%
General Service - Small Non Demand	157,792	147,187	93.3%	31,332	178,518	113.1%
General Service - Small Demand	192,735	155,123	80.5%	40,116	195,238	101.3%
General Service - Medium	263,869	202,097	76.6%	57,479	259,576	98.4%
General Service - Large 0 - 30kV	125,407	94,451	75.3%	29,607	124,058	98.9%
General Service - Large 30-100kV*	90,692	73,791	81.4%	25,040	98,831	109.0%
General Service - Large >100kV*	240,458	190,037	79.0%	70,003	260,041	108.1%
*Includes Curtailment Customers						
SEP	739	844	114.3%	-	844	114.3%
Area & Roadway Lighting	23,890	22,735	95.2%	1,482	24,218	101.4%
Total General Consumers	1,944,467	1,528,939	78.6%	417,166	1,946,105	100.1%
Diesel	9,053	7,414	81.9%	-	7,414	81.9%
Export	38,159	455,326	1193.2%	(417,166)	38,159	100.0%
Total System	1,991,679	1,991,679	100.0%	-	1,991,679	100.0%

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2018
Customer, Demand, Energy Cost Analysis

SUMMARY

	CUSTOMER				DEMAND					ENERGY			
Class	Cost ($000)	Number of Customers	Unit Cost $/Month		Cost ($000)	% Recovery	Billable Demand MVA	Unit Cost $/KVA		Cost ($000)	Metered Energy mWh	Unit Cost ¢/kWh	
Residential - Standard	42,020	295,288	11.86		135,207	0%	n/a	n/a		78,224	3,058,272	6.98	**
Residential - All Electric	34,292	190,133	15.03		270,116	0%	n/a	n/a		113,258	4,427,939	8.66	**
Residential - Seasonal/FRWH	2,207	22,821	8.06		8,900	0%	n/a	n/a		2,555	99,884	11.47	**
Residential - Total	78,519	508,242	12.87		414,223	0%	n/a	n/a		194,037	7,586,096	8.02	**
GS Small - Non Demand	14,113	54,988	21.39	ǂ	71,121	0%	n/a	n/a		41,226	1,622,627	6.92	**
GS Small - Demand	12,531	12,867	81.16	ǂ	85,887	37%	2,623	12.05		54,201	2,146,454	5.05	
General Service - Medium	9,612	2,125	376.96		116,119	92%	7,722	13.83		80,658	3,204,436	2.81	
General Service - Large <30kV	3,573	321	n/a		48,671	100%	4,302	12.14	*	43,556	1,745,362	2.50	
General Service - Large 30-100kV	2,488	40	n/a		24,794	100%	3,358	8.13	*	38,370	1,578,519	2.43	
General Service - Large >100kV	5,875	16	n/a		56,692	100%	7,815	8.01	*	107,887	4,504,939	2.39	
SEP	69	31	184.19		91	0%	n/a	n/a		579	25,500	2.63	**
Area & Roadway Lighting	16,853	157,982	8.89		3,447	0%	n/a	n/a		2,108	82,415	6.74	**
Total General Consumers	143,632	736,612			821,046		25,818			562,622	22,496,347		
Diesel	404	785	42.92		-	0%	n/a	n/a		8,648	14,546	59.45	**
Export	n/a	n/a	n/a		-	0%	n/a	n/a		38,159	9,166,000	0.42	***
Total System	144,036	737,397			821,046		25,818			609,430	31,676,893		

* - includes recovery of customer costs
** - includes recovery of demand costs
*** -includes recovery of customer and demand costs

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2018
Functional Breakdown

SUMMARY

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential - Standard	255,451	115,267	45.1%	23,176	9.1%	12,613	4.9%	39,488	15.5%	64,908	25.4%
Residential - All Electric	417,665	191,325	45.8%	47,857	11.5%	26,375	6.3%	32,662	7.8%	119,446	28.6%
Residential - Seasonal/FRWH	13,662	3,115	22.8%	377	2.8%	196	1.4%	2,032	14.9%	7,942	58.1%
Residential - Total	686,778	309,707	45.1%	71,410	10.4%	39,184	5.7%	74,182	10.8%	192,296	28.0%
General Service - Small Non Demand	126,461	61,189	48.4%	12,472	9.9%	6,794	5.4%	12,747	10.1%	33,258	26.3%
General Service - Small Demand	152,619	78,850	51.7%	15,463	10.1%	8,401	5.5%	7,858	5.1%	42,047	27.6%
General Service - Medium	206,390	114,050	55.3%	21,086	10.2%	11,410	5.5%	8,358	4.0%	51,486	24.9%
General Service - Large <30kV	95,800	59,463	62.1%	10,143	10.6%	5,456	5.7%	2,937	3.1%	17,801	18.6%
General Service - Large 30-100kV	65,652	50,839	77.4%	8,031	12.2%	4,294	6.5%	2,197	3.3%	290	0.4%
General Service - Large >100kV	170,454	142,247	83.5%	22,332	13.1%	0	0.0%	5,625	3.3%	249	0.1%
SEP	739	579	78.3%	91	12.4%	0	0.0%	45	6.0%	24	3.2%
Area & Roadway Lighting	22,408	2,951	13.2%	534	2.4%	288	1.3%	919	4.1%	17,715	79.1%
Total General Consumers	1,527,300	819,875	53.7%	161,562	10.6%	75,828	5.0%	114,869	7.5%	355,166	23.3%
Diesel	9,053	8,648	95.5%	0	0.0%	0	0.0%	0	0.0%	404	4.5%
Export	38,159	38,159	100.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Total System	1,574,512	866,683	55.0%	161,562	10.3%	75,828	4.8%	114,869	7.3%	355,570	22.6%

RATIONALE FOR QUESTION:

Justification for the average monthly usage values used in Manitoba Hydro's bill impact calculations and the basis for Manitoba Hydro's designation of a customer as having electric space heating.

RESPONSE:

b) The difference in Provincial Sales Tax (PST) applied to residential electric customers who are eligible for an electric heat tax reduction is an 82.5% exemption, equivalent to 1.4% (17.5% of the 8% current rate) on the total electrical bill.

In the majority of cases, the "Electric Heat Billed" and "Non Electric Heat Billed" distinction does correspond to those homes eligible and ineligible for the PST reduction. There are exceptions however, such as:

- A residential customer with a treaty number living on reserve land would be provincial tax exempt but may be coded as either "Electric Heat Billed" or "Non Electric Heat Billed" depending on the primary heat source used.
- An apartment suite or home may be heated electrically and coded as "Electric Heat Billed" but if the account is in the name of a commercial business (i.e. Realtor), then the account would be billed the full provincial tax.
- A farm residential account with home and outbuildings served through the same meter may use oil or wood to heat the primary residence, but if an outbuilding has 10 kW or more of electric heat, then the account is coded as "Electric Heat Billed".

A home with installed electrical capacity for heat but which is heated by some other means would be eligible for a provincial tax reduction dependent on the alternate heat source used. If, for example, the customer had gas heat with supplemental electric baseboard, the customer would receive the tax reduction on the gas account and be billed full tax on the electric account. If a customer was capable of heating all-electrically but chose to burn wood instead, the electric account would be charged tax at the reduced rate.

MKO further suggests that the First Nation basic all-electric class should receive a discount from the uniform rates applicable to Manitoba Hydro's customer classes. In MKO's view, this discount should be based upon the bill amount paid by customers with natural gas heating and further remove the recovery of mitigation costs and water rental payments to the Province of Manitoba from the rate.

MKO suggests that the revenue shortfall attributed to the amount of discount related to mitigation costs and water rentals should be allocated to and recovered from all other customers in all electric customer classes. It further recommends that the shortfall associated with the "equivalent to natural gas" subsidy be allocated to and recovered from all natural gas customers.

Manitoba Hydro is of the view that its response to these suggestions and the underlying assumptions associated therewith are matters for argument and not evidence. Nevertheless Manitoba Hydro wishes to make clear that it does not accept that there exists a sound basis for excluding mitigation costs or water rental fees from rates applicable to First Nation customers. Further, Manitoba Hydro notes that under average cost ratemaking and uniform rates, rural and northern customers already receive a subsidy benefit due to the pooling of costs with those associated with service to higher customer density zones. The unbundling of the embedded cost rates would necessitate changes to uniform rates legislation and expose those customers to the higher cost of service associated with being served in remote and low customer density regions.

The matter of setting electric rates reflective of energy costs associated with another energy source is not a cost of service based approach, and in fact completely disconnects rates from the cost of providing electricity. Furthermore such a concept is short sighted and relies on the continuance of the current state of energy pricing, taxation and economics.

For example, the introduction of a carbon tax may have significant impacts on the cost of heating a home with natural gas and under the rate scenario described by MKO, such costs would necessarily be reflected in the rates to northern electrically heated homes. Furthermore, if there were to be a return to the mid 2000's natural gas market environment when prices were five times today's average natural gas price, rates under the MKO scenario may be well beyond the proposed and indicated level of Manitoba Hydro's electricity rates.

113

areas, as the costs of serving them are pooled with the costs for serving higher concentrations of urban customers.

Uniform rates came into effect on November 1, 2001. Prior to that date, Manitoba Hydro administered three rate zones with basic charges and first block energy charges reflecting the increased cost of serving lower density zones. Please see Attachment 4 for information on zone rates in effect prior to November 1, 2001.

With the implementation of uniform rates, all rates were harmonized to the level of the former Zone 1 rate, which applied to the City of Winnipeg. As Zone 2 and 3 rates were formerly higher than Zone 1 in respect to the higher cost to serve customers in those Zones, there was a reduction to residential revenues of approximately $12.9 million. Stated differently, rural and remote customers saved approximately $12.9 million with the equalization of rates to the levels set for the City of Winnipeg as Zone 1.

Previously, the Cost of Service Study included an adjustment to class revenues to offset any revenue reduction that resulted from the implementation of uniform rates legislation. The adjustment ensured that the cost of the uniform rate policy was broadly shared among all customer classes. Order 164/16 eliminated this adjustment from the Cost of Service Study.

8. Rate Design for Electric Heat Customers

Manitoba Hydro provides the following alternative revenue neutral rate structure for information purposes only.

As previously stated, Manitoba Hydro's billing system maintains energy end use information on residential customer accounts in order to appropriately apply the provincial energy tax on energy consumed. The data shown in Figure 2 above separately identifies Electric Heat Billed (All Electric) versus Non Heat Billed customers (Standard).

The rate design scenario shown below segregates Electric Heat Billed customers from Non Heat Billed customers for the purpose of deliberately shifting a portion of the proposed overall rate increase away from the former and onto the latter.

As an initial step, the requested 7.9% increase is applied to all revenues and then an amount of revenue is shifted from the Electric Heat Billed customers to the Non Heat Billed customers such that the energy charge for Non Heat Billed customers would be approximately two percentage points higher than the class average increase of 7.9%. This would result in the shift of approximately $5.2 million of revenue requirement from Electric Heat Billed customers to be paid by Non Heat Billed customers.

The resulting revenues by sub class are shown in Figure 6 below.

Figure 6. Revenue calculations for residential sub-classes (Illustrative for discussion purposes only). Forecast customer count and energy consumption for 2018/19 from the 2017 Electric Load Forecast.

	Customer Count Average	Energy GWh	Revenues Standard Design	Revenues Alternative Scenario	Revenue Adjustment (All Elec to Standard)
Residential Basic Standard	297,600	3,170	$ 311,434.9	$ 316,633.3	$5,198.4
Residential Basic All Electric	195,200	4,503	$ 419,745.6	$ 414,560.9	($5,184.8)
Residential Seasonal	19,300	73	$ 8,438.0	$ 8,438.0	
Residential Diesel	600	9	$ 851.7	$ 851.7	
Residential FRWH *	-	15	$ 1,161.1	$ 1,161.1	
	512,700	**7,770**	**$ 741,631.3**	**$ 741,645.0**	

*Residential FRWH services are included in the customer count for the other sub-classes.

The illustrative rates for Residential Basic Standard (Non Heat Billed) and Residential Basic All Electric (Electric Heat Billed) that would result in this revenue shift are shown in Figure 7 below.

Figure 7. Illustrative Rates - Basic All Electric & Basic Standard.

	Basic Charge	Energy Charge
Residential Basic Standard	$8.72	0.09007
Residential Basic All Electric	$8.72	0.08728

For information purposes, a comparison of the Proof of Revenue is provided in Figure 8 below. The Proof of Revenue for Manitoba Hydro's proposed residential rate for April 1, 2018 (a 7.9% increase on all rate components with no differentiation) is shown in the first table of Figure 8. An illustrative Proof of Revenue for the alternative rate scenario is shown in the bottom table of Figure 8.

119

Figure 8. Illustrative Proof of Revenues.

PROOF OF REVENUE

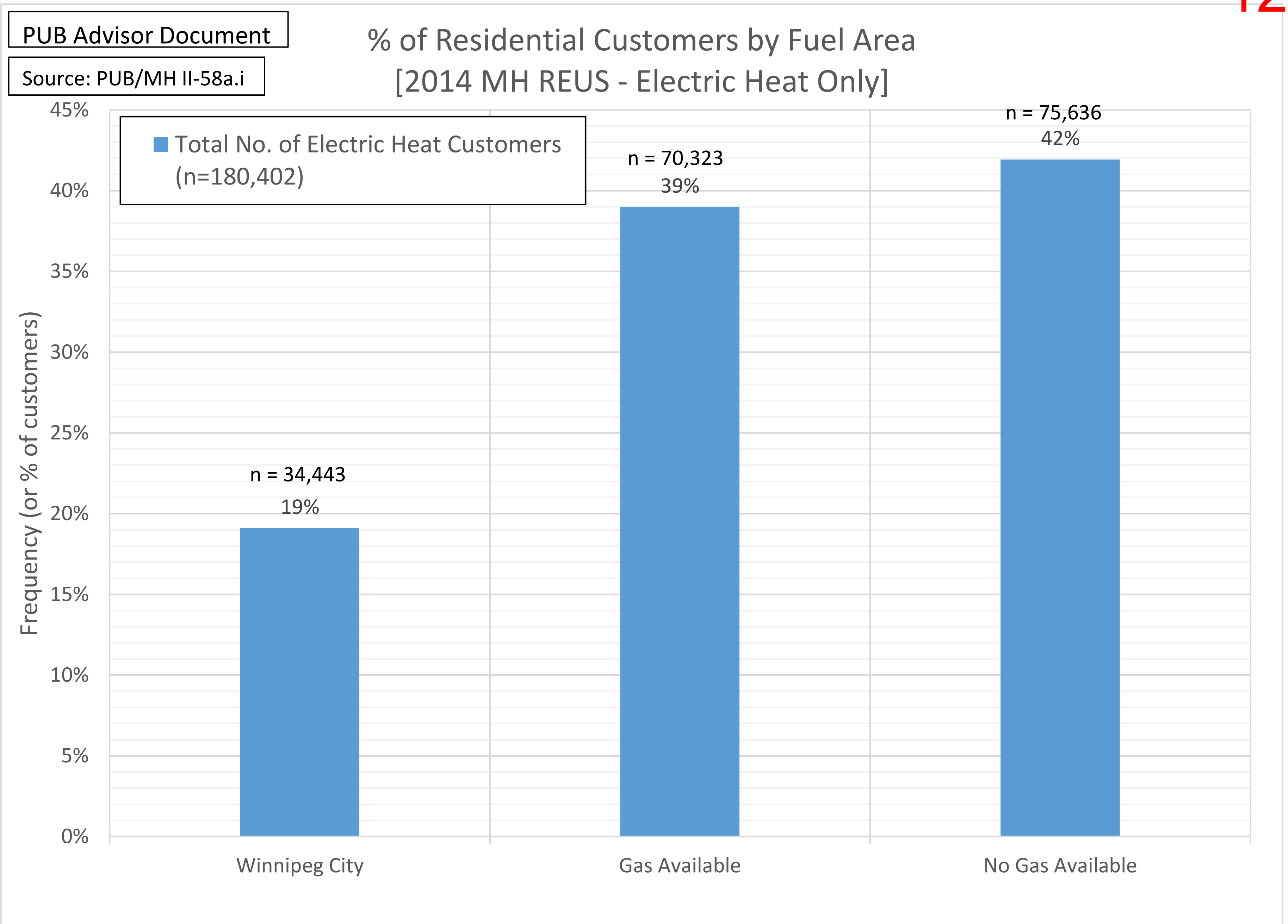
Approved August 1, 2017 Rates vs Proposed April 1, 2018 Rates
for 12 months ending March 31, 2019
Rates as per Appendix 9.2 (Updated)

	Calculated Revenue Aug 2017 Rates	Calculated Revenue Prop Apr 2018 Rates	Diff. in Revenue Dollars	Diff. in Revenue Percent
Basic Std	288,641,558	311,434,897	$22,793,340	7.90%
Basic AE	389,030,015	419,745,623	$30,715,608	7.90%
Diesel	789,348	851,675	$62,327	7.90%
Seasonal	7,820,199	8,438,031	$617,832	7.90%
FRWH	1,076,172	1,161,120	$84,948	7.89%
RESIDENTIAL	**687,357,292**	**741,631,347**	**$54,274,055**	**7.90%**

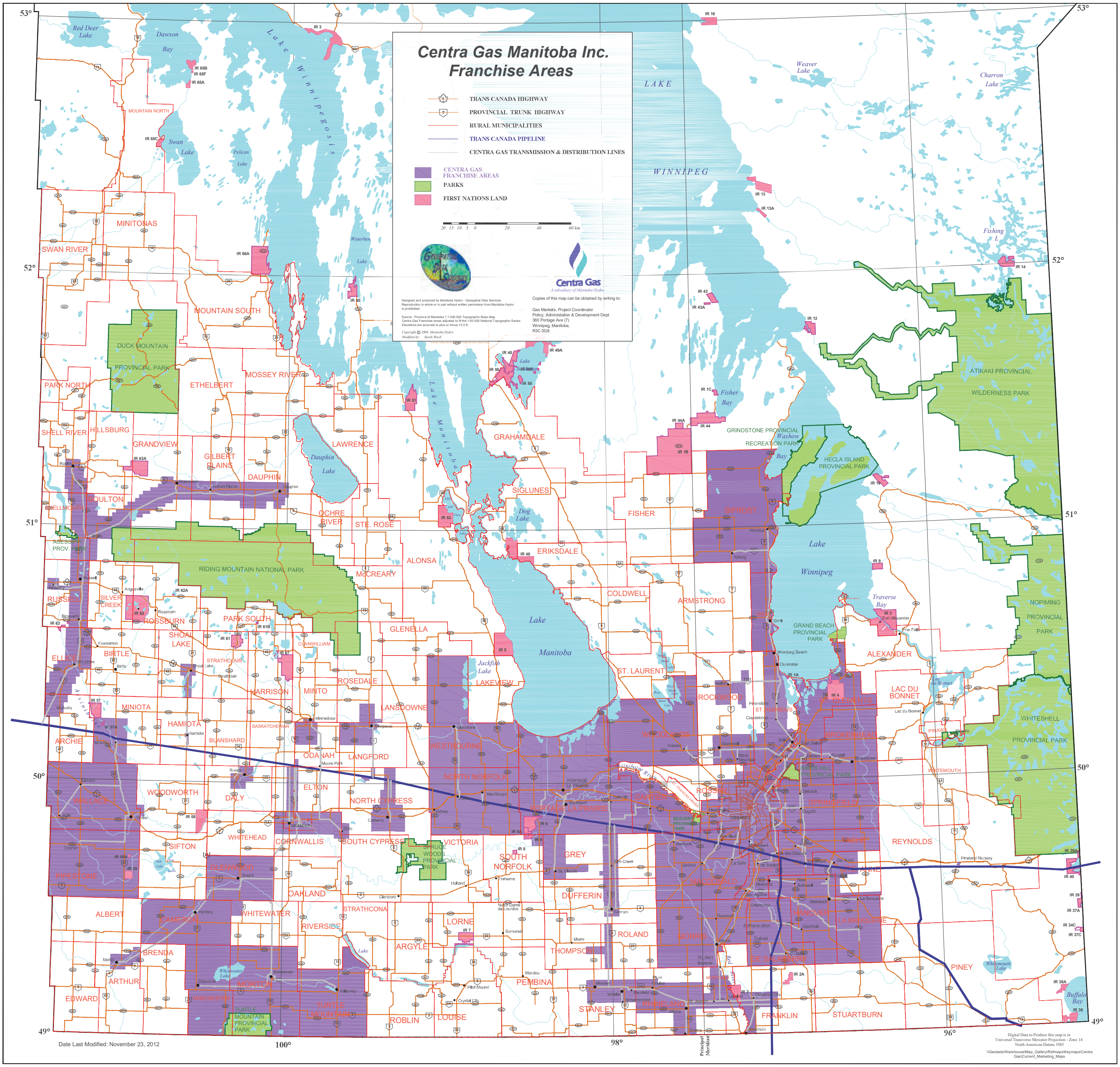
PROOF OF REVENUE

Approved August 1, 2017 Rates vs Alternative Rate Scenario
for 12 months ending March 31, 2019
Alternative Rate Scenario - Illustrative Rates

	Calculated Revenue Aug 2017 Rates	Calculated Revenue Prop Apr 2018 Rates	Diff. in Revenue Dollars	Diff. in Revenue Percent
Basic Std	288,641,558	316,633,296	$27,991,738	9.70%
Basic AE	389,030,015	414,560,867	$25,530,851	6.56%
Diesel	789,348	851,675	$62,327	7.90%
Seasonal	7,820,199	8,438,031	$617,832	7.90%
FRWH	1,076,195	1,161,120	$84,925	7.89%
RESIDENTIAL	**687,357,314**	**741,644,989**	**$54,287,674**	**7.90%**


PUB Advisor Document
Source: PUB/MH II-58a.i
% of Residential Customers by Fuel Area
[2014 MH REUS - Electric Heat Only]
Total No. of Electric Heat Customers (n=180,402)
Frequency (or % of customers)
45%
40%
35%
30%
25%
20%
15%
10%
5%
0%
n = 34,443
19%
n = 70,323
39%
n = 75,636
42%
Winnipeg City
Gas Available
No Gas Available

Centra Gas Manitoba Inc. - 2013/14 GRA Appendix 3.1



114

block energy charge with no increase to the 2016/17 customer charge and energy charge for the first 500 kWh at current levels, $7.82/month and 7.93¢/kWh. The residential survey reports that there are the 324,274 non-LICO customers, using an average of 16,422 kWh annually. The lower customer charge would reduce revenues by about $2.4 million (compared to a rate of $8.44/month) and the lower energy charge for the first 500 kWh would reduce rates by $10.7 million (compared to the proposed rate of 8.556¢/kWh), for a total of about $13.4 million. Recovering those revenues from the remaining non-LICO residential energy above 500 kWh/month would require that the tail-block rate be set at 0.365¢ higher than proposed rate, or 8.921¢/kWh.

Table 6 summarizes my rate proposals, based on the proposed August 1, 2017 permanent rates. The recovery rates (the increased energy rate for other customers) are shown for the LICO-125 rate and the non-LICO space-heating rate. The cost of the LICO-125 space-heating rate is included in the other two discount proposals.

Table 6: Summary of Rate Proposals

	MH proposed	LICO-125 All	Non-LICO ESH	LICO-125 ESH	Non-LICO Residential
Basic Charge	$8.44	$0	$8.44	$0	$7.82
First Block	8.556¢	4.556¢	4.556¢	4.556¢	7.93¢
Remainder	8.556¢	8.556¢	8.556¢	8.556¢	8.909¢
First Block kWh					
Summer	—	500	—	500	500
Spring	—	500	150	650	500
Fall	—	500	250	750	500
Winter	—	500	500	1,000	500
Recovery rate		0.22¢	0.12¢		

PUB/GAC - 1 Reference: Chernick Evidence p.35 of 101

a) Please identify potential options for Manitoba Hydro to collect income information and determine eligibility for discounted lower income rates, with reference to successful practices in other jurisdictions.

b) If Manitoba Hydro is to rely on customers applying for lower income rates and providing income eligibility evidence on a regular (e.g. annual) basis, please comment whether the revenue risk shifts from unexpectedly more customers participating to unexpectedly fewer customers participating.

Response:

a) It is Mr. Chernick's understanding that Manitoba Hydro currently determines LICO-125 qualification to establish eligibility for the Affordable Energy Program (AEP). For those customers already qualified for the AEP, eligibility for the LICO rate should be automatic. For other customers, Manitoba Hydro can follow the practice that it currently follows for the AEP.

   As for determining continuing eligibility, Mr. Chernick understands that Manitoba's Employment & Income Assistance program (part of Manitoba Department of Families), reported to the bill affordability working group that they have their clients give permission for the CRA to send the income lines from their annual tax return. Manitoba Hydro could follow a similar procedure, or rely on the EIA to certify eligibility.

   Mr. Chernick has not conducted a survey of other jurisdictions. He is aware that some utilities use eligibility for government programs as eligibility criteria for utility programs.

b) The "revenue risk" in this case would be that Manitoba Hydro collects more than was expected in the rate case, due to lower enrollment in the LICO rate program. That would result, all else equal, in Manitoba Hydro having higher retained earnings, which may result in a lower rate increase in the next GRA.

PUB/GAC - 2 Chernick Evidence p.38 of 101; Coalition/MH I-89

Preamble: April DDH are higher than October DDH, as shown in the response to Coalition/MH I-89.

Request: Please confirm whether the Electric Space Heating initial block should be as proposed (100 kWh for April and 250 kWh for October) or should different initial blocks be considered.

Response:

Other initial blocks could be considered. Mr. Chernick picked those block sizes to avoid having many customers with usage ending in the block. The data in GAC/MH I-1 suggest that bills rendered in the spring (which include winter usage) should have a larger discounted block than bills rendered in the fall (which include summer usage). This is not inconsistent with Mr. Chernick's proposal for blocks based on usage in the seasons covered by each bill.

PUB/GAC - 3 Reference: Chernick Evidence p. 39 of 101

Please provide the increase in energy rate if the $44.5 million in lost revenues from the electric space heating rate were to be recovered from only non-LICO residential customers.

Response:

As stated on p. 32, line 23 of Mr. Chernick's testimony, the increase to the non-LICO residential energy rate would be about 0.8¢.

PUB/GAC - 4 Reference: Chernick Evidence p.40 of 101; PUB/MH I-125c; PUB/MH II-58

a) Please recalculate Table 6 assuming the previous interim 3.36% rate increases are approved as final.

b) Provide a table or tables of annual bill impacts in monthly consumption increments of 250 kWh (from 250 kWh to 7000 kWh per month) for each of the rate design proposals shown in Table 6:

- LICO-125
- Electric Space Heating
- LICO-125 Electric Space Heating
- Non-LICO Residential

c) Please provide a table of bill impacts using the consumption figures and load factors in Manitoba Hydro's GRA Appendix 9.6 for the following customer classes and consumptions. Assume interim August 1, 2017 rates as the starting point and include Manitoba Hydro's proposed rate increases for April 1, 2018, with the recovery rates proposed by Mr. Chernick in Table 6 of his evidence.

- General Service Small <50kVA
- General Service Small 100kVA
- General Service Medium 1000kVA
- General Service Large 50,000kVA

d) Provide a table of annual bill impacts in the same form as (b) but assume that the reduced revenue from the LICO-125 and Electric Space Heating rate design proposals is recovered only from the Residential class.

e) Please show the reduced revenue resulting from each of the rate design proposals and estimate the total revenue that would be collected from Residential customers and from General Service customers based on the proposed recovery rates.

f) Please clarify whether the non-LICO residential tail block rate should be 8.921¢/kWh as at line 11 or should be 8.909 ¢/kWh as in Table 6.

Response:

a) See table below.

		MH proposed	LICO-125 All	Non-LICO ESH	LICO-125 ESH	Non-LICO IBR
Basic Charge		$8.08	$0	$8.08	$0	$7.82
First Block		8.196¢	4.196¢	4.196¢	4.196¢	7.93¢
Remainder		8.196¢	8.196¢	8.196¢	8.196¢	8.352¢
First Block kW.h						
Summer		—	500	—	500	500
Spring		—	500	150	650	500
Fall		—	500	250	750	500
Winter		—	500	500	1,000	500
Recovery rate	Recovery from:					
	Non-LICO residential (NLR)		$0.00966			
	All non-LICO, non-SEP		$0.00246			
	Non-discounted NLR kWh			$0.00407		
	Non-discounted non-LICO			$0.00096		

b) See Attachment MH/Chernick I-10.
c) See Attachment PUB/GAC 1-4c.
d) See Attachment PUB/GAC 1-4d.
e) See Attachment PUB/GAC 1-4c. Assuming that the revenue recovery is spread over all classes (other than SEP, LICO and the discounted block for ESH), the recovery for LICO would be about $12.8 million from residential $37.5 million from GS; and for ESH, the recovery would be $4.6 million from residential and $14.7 million from GS.
f) The value should be 8.925¢/kWh in both places.

PUB/GAC - 5 Reference: Chernick Evidence Pages 34 and 35 of 101; PUB/MH I-132

Preamble: Mr. Chernick suggests that the LICO-125 rate discount could be funded by all non-lower income ratepayers and not just those in the Residential class.

Request: In light of the revenue to cost coverage ratios that indicate Residential customers are covering 95% of the costs allocated to the Residential class, please explain whether it is appropriate to further reduce the RCC for the Residential class at the expense of other classes whose RCCs may be in excess of 105%.

Response:

Mr. Chernick does not believe that PCOSS18 provides much clarity regarding the costs attributable to each class. He is therefore not unduly perturbed by the reported RCCs. In Mr. Chernick's LICO rate proposal, the non-LICO residential rates would rise; if the PUB believes that the public interest is served by reducing the energy burden on LICO customers , bringing down those customers' bills, some other group of customers will need to pay a larger portion of the Manitoba Hydro revenue requirement.

MH/CHERNICK I - 9

Reference:

Section V, part A. page 38

Question:

Please confirm that the 8.909¢/kWh figure in Table 6 at page 38 should be 8.921¢/kWh per line 11 of page 38.

Response:

Following some corrections and updates, Mr. Chernick finds that the correct value is 8.925¢/kWh.

MH/CHERNICK I - 10

Reference:

Section V, part C. Table 6, page 38

Preamble:

Summary of Chernick rate proposals, based upon August 1, 2017 rates.

Question:

a) Please provide Proof of Revenue Statements for the rate proposals shown in Table 6. Please provide all source data, calculations and working papers used to derive the Proof of Revenue statements.
b) Please provide Bill Impact Tables for each of the rate proposals shown in Table 6, in the same format as found in Figure 9, page 15 of Appendix 9.14. Please provide all source data, calculations and working papers used to derive the Bill Impact Tables.

Response:

a) Mr. Chernick has not conducted this analysis. If he has the necessary data in spreadsheet format, he will attempt to provide it prior to the hearing.

b) See Attachment MH/Chernick I-10.

MH Proposed LICO-125 All

kWh	$ / Month	$ / Month	Difference	% Diff
250	$29.83	$11.39	($18.44)	-61.82%
750	$72.61	$44.17	($28.44)	-39.17%
1 000	$94.00	$65.56	($28.44)	-30.26%
2 000	$179.56	$151.12	($28.44)	-15.84%
5 000	$436.24	$407.80	($28.44)	-6.52%

Basic Charge	$8.44	$0.00
1st Block	0.08556	0.04556
Remainder	0.08556	0.08556
First Block kWh	500	500

SUMMER

	MH Proposed	Non-LICO ESH		
kWh	**$ / Month**	**$ / Month**	**Difference**	**% Diff**
250	$29.83	$33.26	$3.43	11.50%
750	$72.61	$82.91	$10.30	14.19%
1 000	$94.00	$107.73	$13.73	14.61%
2 000	$179.56	$207.02	$27.46	15.29%
5 000	$436.24	$504.89	$68.65	15.74%

				Recovery
Basic Charge	$8.44	$8.44		
1st Block	0.08556	0.04556	LICO	$0.00966
Remainder	0.08556	$0.09929	ESH	$0.00407
				$0.01373
First Block kWh	0	0		

SPRING

	MH Proposed	Non-LICO ESH		
kWh	**$ / Month**	**$ / Month**	**Difference**	**% Diff**
250	$29.83	$25.20	($4.63)	-15.52%
750	$72.61	$74.85	$2.24	3.08%
1 000	$94.00	$99.67	$5.67	6.03%
2 000	$179.56	$198.96	$19.40	10.80%
5 000	$436.24	$496.83	$60.59	13.89%

Basic Charge	$8.44	$8.44
1st Block	0.08556	0.04556
Remainder	0.08556	$0.09929
First Block kWh	150	150

FALL

MH Proposed **Non-LICO ESH**

kWh	$ / Month	$ / Month	Difference	% Diff
250	$29.83	$19.83	($10.00)	-33.52%
750	$72.61	$69.48	($3.13)	-4.31%
1 000	$94.00	$94.30	$0.30	0.32%
2 000	$179.56	$193.59	$14.03	7.81%
5 000	$436.24	$491.46	$55.22	12.66%

Basic Charge	$8.44	$8.44
1st Block	0.08556	0.04556
Remainder	0.08556	$0.09929
First Block kWh	250	250

WINTER

	MH Proposed	Non-LICO ESH		
kWh	**$ / Month**	**$ / Month**	**Difference**	**% Diff**
250	$29.83	$19.83	($10.00)	-33.52%
750	$72.61	$56.04	($16.57)	-22.82%
1 000	$94.00	$80.87	($13.13)	-13.97%
2 000	$179.56	$180.16	$0.60	0.33%
5 000	$436.24	$478.03	$41.79	9.58%

Basic Charge	$8.44	$8.44
1st Block	0.08556	0.04556
Remainder	0.08556	$0.09929
First Block kWh	500	500

SUMMER

kWh	MH Proposed $ / Month	LICO-125 ESH $ / Month	Difference	% Diff
250	$29.83	$11.39	($18.44)	-61.82%
750	$72.61	$44.17	($28.44)	-39.17%
1 000	$94.00	$65.56	($28.44)	-30.26%
2 000	$179.56	$151.12	($28.44)	-15.84%
5 000	$436.24	$407.80	($28.44)	-6.52%

Basic Charge	$8.44	$0.00
1st Block	0.08556	0.04556
Remainder	0.08556	0.08556
First Block kWh	500	500

SPRING

kWh	MH Proposed $ / Month	LICO-125 ESH $ / Month	Difference	% Diff
250	$29.83	$11.39	($18.44)	-61.82%
750	$72.61	$38.17	($34.44)	-47.43%
1 000	$94.00	$59.56	($34.44)	-36.64%
2 000	$179.56	$145.12	($34.44)	-19.18%
5 000	$436.24	$401.80	($34.44)	-7.89%

Basic Charge	$8.44	$0.00
1st Block	0.08556	0.04556
Remainder	0.08556	0.08556
First Block kWh	650	650

FALL

	MH Proposed	LICO-125 ESH		
kWh	**$ / Month**	**$ / Month**	**Difference**	**% Diff**
250	$29.83	$11.39	($18.44)	-61.82%
750	$72.61	$34.17	($38.44)	-52.94%
1 000	$94.00	$55.56	($38.44)	-40.89%
2 000	$179.56	$141.12	($38.44)	-21.41%
5 000	$436.24	$397.80	($38.44)	-8.81%

Basic Charge	$8.44	$0.00
1st Block	0.08556	0.04556
Remainder	0.08556	0.08556
First Block kWh	750	750

WINTER

	MH Proposed	LICO-125 ESH		
kWh	**$ / Month**	**$ / Month**	**Difference**	**% Diff**
250	$29.83	$11.39	($18.44)	-61.82%
750	$72.61	$34.17	($38.44)	-52.94%
1 000	$94.00	$45.56	($48.44)	-51.53%
2 000	$179.56	$131.12	($48.44)	-26.98%
5 000	$436.24	$387.80	($48.44)	-11.10%

Basic Charge	$8.44	$0.00
1st Block	0.08556	0.04556
Remainder	0.08556	0.08556
First Block kWh	1000	1000

kWh	MH Proposed $ / Month	Non-LICO Residential $ / Month	Difference	% Diff
250	$29.83	$27.65	($2.18)	-7.31%
750	$72.61	$73.22	$0.61	0.84%
1 000	$94.00	$98.96	$4.96	5.28%
2 000	$179.56	$201.94	$22.38	12.46%
5 000	$436.24	$510.88	$74.64	17.11%

Basic Charge	$8.44	$7.82
1st Block	0.08556	0.0793
Remainder	0.08556	0.10298
First Block kWh	500	500

115

Figure 8.13 Comparison of Unit Costs

Customer Class	Cost[1]	PCOSS14-Amended	PCOSS14 164/16	PCOSS18	Rates Aug 1, 2016[2]
Residential	Customer($/mth)	20.69	13.68	12.76	7.82
	Energy (¢/kWh)	6.32	7.04	7.53	7.93
GSS Non Demand	Customer ($/mth)	37.32	31.99	27.26	21.20
	Energy (¢/kWh)	6.25	6.23	6.57	5.782
GSS Demand	Customer ($/mth)	54.59	52.76	244.57	29.89
	Demand ($/KVA)	6.22	11.27	11.45	9.77
	Energy (¢/kWh)	5.22	4.64	4.79	3.816
GSM	Customer ($/mth)	302.13	320.03	372.96	31.55
	Demand ($/KVA)	6.71	11.90	13.14	9.77
	Energy (¢/kWh)	4.16	2.87	2.65	3.816
GSL 0-30kV	Customer ($/mth)	n/a	n/a	n/a	n/a
	Demand ($/KVA)	6.88	11.67	11.54	8.29
	Energy (¢/kWh)	3.88	2.45	2.36	3.589
GSL 30-100kV	Customer ($/mth)	n/a	n/a	n/a	n/a
	Demand ($/KVA)	3.98	7.15	7.65	7.10
	Energy (¢/kWh)	3.49	2.39	2.30	3.336
GSL >100kV	Customer ($/mth)	n/a	n/a	n/a	n/a
	Demand ($/KVA)	2.62	6.85	7.51	6.32
	Energy (¢/kWh)	3.47	2.36	2.26	3.233

[1] GSL demand unit costs include recovery of customer costs, Residential and GSS ND energy unit costs include recovery of Demand costs

[2] Revenue, as well as revenue requirement, included in the PCOSS are based on current rates to allow results to be used as a guide for rate differentiation. August 1, 2016 rates are therefore the appropriate comparison to unit costs from PCOSS18.

TOU Rate Attributes

- Clear Price Signal that Addresses all Energy Consumption
  - Equity for all rate class participants
  - Eliminates need for baseline determination
- Time-of-Use Price Signal relates to Market Pricing Behavior
  - Export market opportunity minus rate volatility
  - Cost allocation methodologies and cost-based rate setting
  - Predictable and uniform future rate projections
- Supports Positive Customer Consumption Behavior
  - Clear on-peak price signal supports customer engagement through conservation, load shifting, demand response…
  - Energy centric rate reduces influence of capacity charges
  - Compliments potential future alternative rate structures

Manitoba Hydro

TOU Rate Applications

- Original TOU Application – 11/12 GRA
  - Transmission and sub-transmission rate classes
  - Deferred by PUB pending Cost-of-Service review
  - Differentiated rate increases / TOU rates
- Subsequent TOU Application – 15/16 GRA
  - Transmission and sub-transmission rate classes
  - Deferred pending Cost-of-Service review

Manitoba Hydro

Time-of-Use Definitions

- On-Peak Hours
  - 6:00 am to 10:00 pm, Monday to Friday
  - Approx 45% of annual hours
- Off-Peak Hours
  - 10:00 pm to 6:00 am, Monday to Friday
  - 24 hours, Saturday to Sunday, Statutory Holidays
  - Approx 55% of annual hours
- Seasonal Periods
  - Winter Season, Four Months (Dec to Mar)
  - Summer Season, Eight Months (Apr to Nov)

Manitoba Hydro

TOU Hours / Seasons

Hours	Summer (Apr 1 - November 30)	Winter (December 1 - March 31)
Peak	Monday through Friday except Statutory Holidays from: 6:01 hours - 22:00 hours	Monday through Friday except Statutory Holidays from: 06:01 hours - 22:00 hours
Off-Peak	All night time hours from 22:01 hours - 06:00 hours incl Stat Holidays	

Summer:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Monday																								
Tuesday																								
Wednesday			Off-Peak											On-Peak										
Thursday																								
Friday																								
Saturday																								
Sunday																								
Stat Holidays																								

Winter:	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
Monday																								
Tuesday																								
Wednesday			Off-Peak											On-Peak										
Thursday																								
Friday																								
Saturday																								
Sunday																								
Stat Holidays																								

Illustrative TOU Rate Impacts

- On-Peak Load Consumption Factor
  - ratio of on-peak energy consumed to on-peak demand
- Current On-Peak / Off-Peak Demand Levels
  - on-peak demand serves as billing demand
- On-Peak/Off-Peak Energy Consumption Ratio
  - on-peak rates higher than off-peak rates
- Winter/Summer On-Peak Energy Consumption Ratio
  - winter on-peak rates higher summer on-peak rates
- Actual Demand / Contracted Capacity Ratio
  - minimum billing demand equal to 50% of contract demand

Example 1 - Illustrative TOU Rates

	Current Rates	Winter TOU (illustrative)		Summer TOU (illustrative)	
Energy Charges					
On-Peak (kWh)	$0.0323	$0.0566	75.1%	$0.0466	44.1%
Off-Peak (kWh)	$0.0323	$0.0266	(17.7%)	$0.0266	(17.7%)
Capacity Charges					
Demand (kVA)	$6.32	$3.48	(55%)	$3.48	(55%)
Minimum Demand	25% Contract	50% Contract		50% Contract	

Manitoba Hydro notes that the potential impact to individual customers of a TOU rate design varies significantly, depending upon their energy usage patterns and the degree to which they may be able to shift energy usage between time periods during the day. For example, the range of bill impacts by each of the fourteen customers in the GSL>100 class under the illustrative August 1, 2016 rate design scenario was shown in the response to MIPUG/MH I-5c, and is provided in more detail below.

	Bill Impact of TOU vs Standard GSL > 100 Rate Design ($)	Customer under TOU rate design
Customer 1	900,200	Higher bill
Customer 2	438,500	Higher bill
Customer 3	140,300	Higher bill
Customer 4	114,700	Higher bill
Customer 5	39,500	Higher bill
Customer 6	36,800	Higher bill
Customer 7	400	Higher bill
Customer 8	(29,700)	Lower bill
Customer 9	(70,800)	Lower bill
Customer 10	(96,900)	Lower bill
Customer 11	(103,800)	Lower bill
Customer 12	(221,500)	Lower bill
Customer 13	(294,400)	Lower bill
Customer 14	(711,000)	Lower bill
7 customers	$ (1,528,100)	Lower revenues - TOU
7 customers	$ 1,670,400	Higher revenues - TOU

Therefore, in the illustrative rates in the scenario shown above, one half of the GSL > 100 customers would have an economic incentive to choose the TOU rate option and the other half would benefit from remaining on the standard rate design. This situation opens the door to self-selection by customers, based solely on their potential to benefit from one rate design or the other.

The result of the potential self-selection by GSL > 100 customers is that only customers whose bills could be lower under the TOU option would switch rates and therefore Manitoba Hydro would see a revenue shortfall of approximately $1.5 million for the GSL > 100 class.

Mr. Bowman acknowledges that Manitoba Hydro, in this scenario, may experience revenue losses of approximately $1.5 million based on the 2016 TOU rate design proposal due to the self-selection of customers favored by such a rate design (Page 7-15 line 20 to

116

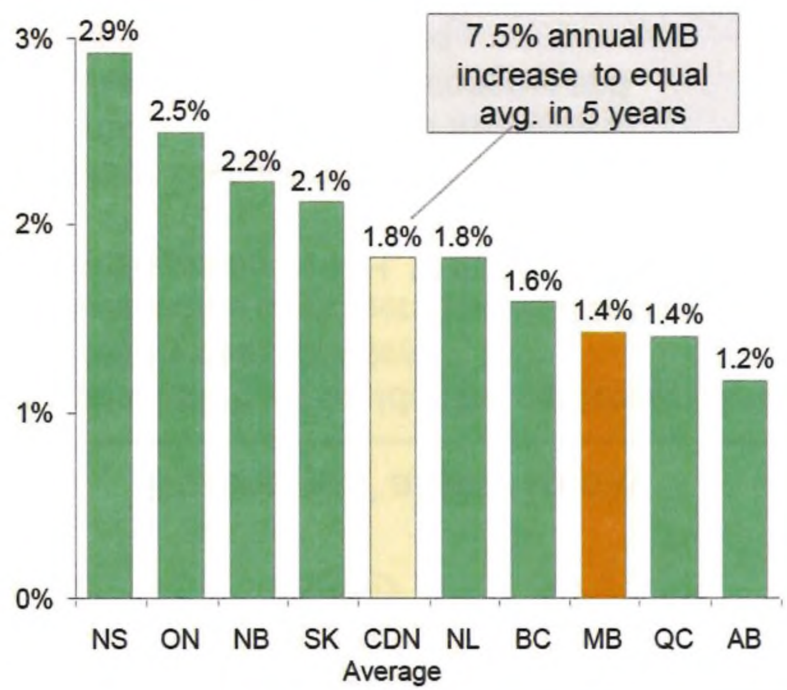
3 Domestic rev.

PRIVILEGED AND CONFIDENTIAL – PREPARED IN CONTEMPLATION OF REGULATORY LITIGATION

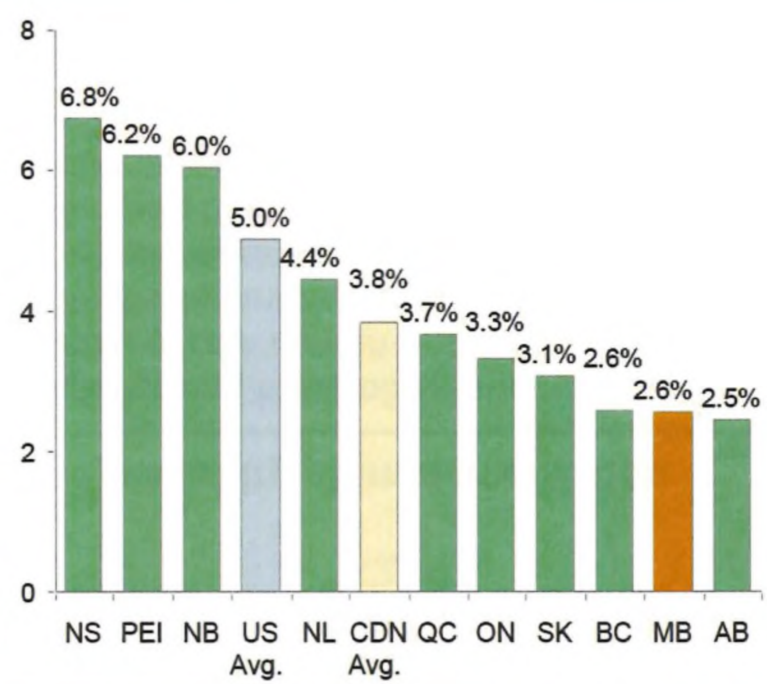
Manitoba residents pay lower share of disposable income for electricity than peers; total household energy costs also low

Residential

Average residential bill[1] as share of average household disposable income



Household energy costs (gas and electric) as % of disposable income



Even with modest increases, customers would continue to spend a relatively small proportion of income on energy

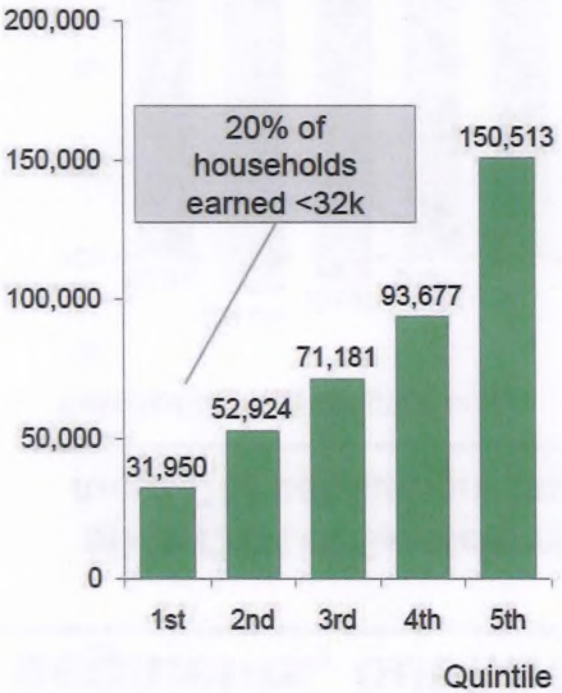
Note: Disposable income calculated based on Provincial per capita disposable income multiplied by average household size by province; average electric bill is for 1,000 kWh annual usage
1. Average bill for a customer with non-electric heating
Source: Manitoba Hydro, StatCan Census data, Institut de la statistique du Quebec

However, residential rates the same for all households despite large portion (15%) of population in poverty

Residential – Low income

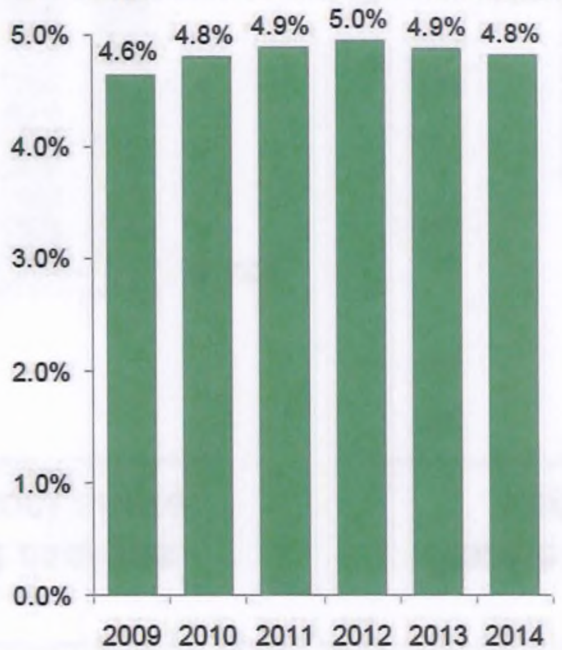
MB household incomes vary significantly

2011 After tax annual income 2015 $[1]



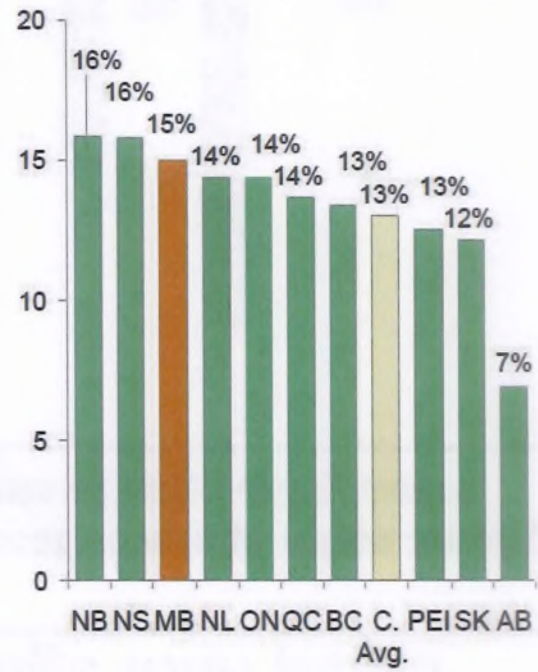
~5% of MB population receive welfare assistance

% of Population with welfare assistance



15% of population below poverty line

2014 poverty rate (% of population) based on LICO



1. 2011 after-tax average income per census family by quintile; Series discontinued in 2011; 2011 data adjusted to 2015 $ using historical inflation data. 2. Share of total population including children, non-working population using low income measure methodology, after tax
Source: Statistics Canada; Citizens for Public Justice

Manitoba Hydro submitted that a bill affordability program falls outside of Manitoba Hydro's legislative mandate as set out in *The Manitoba Hydro Act.* According to Manitoba Hydro, the utility is legally required to recover the cost of supplying power pursuant to section 39(1) of that statute and section 43(3) prohibits the use of Manitoba Hydro's funds for purposes of the Government or any government agency. Manitoba Hydro further submitted that the Board does not have the jurisdiction to order it to implement a bill affordability program as the Board's jurisdiction is limited to setting the prices to be charged for the provision of power but does not extend to the setting of social policy. Manitoba Hydro also indicated that in *Dalhousie Legal Aid Service v. Nova Scotia Power Inc.,* 2006 NSCA 74, the Nova Scotia Court of Appeal found that the Nova Scotia Utility and Review Board had no jurisdiction to order a bill affordability program to be implemented. Manitoba Hydro acknowledged that cases in other jurisdictions are not determinative of this Board's jurisdiction to order such a program in Manitoba.

Board Findings:

The Board recognizes that higher electricity rates will have an impact on lower income ratepayers. This is a particular concern with respect to all-electric customers, many of whom live in areas in which natural gas is not available as an alternative heating source.

The Board sees merit in the approach recommended by GAC's witness to start a collaborative process to determine the best options to address affordability issues. However, it is the Board's view that Manitoba Hydro is in a better position to lead such a process than the Board. Manitoba Hydro has expertise with respect to low-income programs, as evidenced by the recent successes in the AEP discussed in Chapter 10.0.

The Board therefore directs Manitoba Hydro to initiate a collaborative process to develop a bill affordability program harmonized with Manitoba Hydro's other programs supporting low-income ratepayers. Manitoba Hydro shall file, for Board approval, Terms of Reference for this process (including proposed facilitators and proposed stakeholder participants) by October 31, 2015. The Terms of Reference should explain and include items in scope as well as items specifically out of scope. If Terms of Reference cannot be agreed upon between Manitoba Hydro and participating stakeholders, the Board is prepared to receive submissions from the parties and adjudicate the appropriate scoping. The goal of the process should be to develop a program for implementation within one year from the approval of the Terms of Reference.

The Board is prepared to entertain submissions for participant funding to be charged to Manitoba Hydro in appropriate cases and in accordance with the Board's Rules of Practice and Procedure.

Upon completion of the collaborative process the Board will evaluate the options presented and decide on their implementation.

The Board has been asked to consider establishing a bill assistance program before, notably in Order 116/08, in which the Board required Manitoba Hydro to propose such a program for approval. In Order 116/08, the Board concluded that it has jurisdiction to order the implementation of a bill affordability program. This remains the Board's view. However, the Board notes that at this time, it is not ordering such a program to be established and the collaborative process should not be limited to the consideration of special lower income rates. From a policy perspective, there may well be better solutions that have not been proposed to date. Furthermore, the optimal solution may well involve a portfolio of measures rather than a single measure. However, the idea of lower income rates should not be discarded upfront due to jurisdictional concerns.

The Board interprets section 39(1) of *The Manitoba Hydro Act* to require the aggregate price of power realized by Manitoba Hydro to be such as to achieve full cost recovery, subject to the requirement that such rates must be just and reasonable. This is illustrated by several examples:

- The power from historical generating stations is currently being sold for significantly more than the actual cost to generate, while power from new generating stations is sold for significantly less than the cost to generate. Rates are set based on Manitoba Hydro's aggregate revenue requirement, not the cost attributable to individual stations.

- While Manitoba Hydro exports some power (primarily firm power) at prices higher than the average cost to generate, it also sells opportunity power for less than the average cost to generate, attributing no fixed costs to such power.
- Certain classes of customers, such as existing Curtailable Rate Program customers, achieve benefits not available to other customer classes or customers in the same class.

The Board does not read the legislative requirement for "postage stamp" rates to prohibit the creation of a lower income customer class, provided that no geographic limitations are imposed on such a class. Similarly, while subsection 43(3) prevents the commingling of government funds with Manitoba Hydro funds, it does not prohibit the creation of a rate class that pays less than the average cost to serve such customers.

The Board notes that while Manitoba Hydro is regulated on a cost of service basis, section 26(4) of *The Crown Corporations Public Review and Accountability Act* specifically authorizes the Board to consider "any compelling policy considerations that the Board considers relevant to the matter." In that respect, the Board's jurisdiction is similarly broad as that of the Ontario Energy Board pursuant to *The Ontario Energy Board Act, 1998*. Subsection 26(3) of *The Crown Corporations Public Review and Accountability Act* further stipulates that *The Public Utilities Board Act* applies with any necessary changes to the Board's rate-setting mandate. As such, rates are not only required to meet the requirements of subsection 39(1) of *The Manitoba Hydro Act* but must also be "just and reasonable." In the Board's view, affordability is a factor to consider when setting just and reasonable rates.

As such, it is the Board's intention to evaluate any future proposals for bill assistance programs from a comprehensive policy perspective rather than through the lens of jurisdictional constraints, provided that such proposals fall within the legislative framework set by *The Manitoba Hydro Act*, *The Crown Corporations Public Review and Accountability Act*, and *The Public Utilities Board Act*.

15.0 IT IS ORDERED THAT:

1. The rate increase of 2.75% previously approved as interim on May 1, 2014 **BE AND IS HEREBY APPROVED AS FINAL**.

2. Manitoba Hydro's Application for a 3.95% across-the-board rate increase effective April 1, 2015 **BE AND IS HEREBY DENIED** as filed.

3. A 3.95% overall increase in billed rates for the Basic Charge, the Demand Charge, and the Energy Charge for all rate classes to take effect August 1, 2015, with revenues from a 2.15% portion of the rate increase accruing into a deferral account to be utilized to mitigate the required rate increases when Bipole III enters service and 1.8% accruing to Manitoba Hydro's general revenues, **BE AND IS HEREBY APPROVED**.

4. Manitoba Hydro recalculate and refile, for Board approval, a schedule of rates reflecting a 3.95% increase effective August 1, 2015 to the Basic Charge, Demand Charge, and Energy Charge for all rate classes, together with all supporting schedules including proof of revenue, customer impacts, and revenue requirement.

5. Manitoba Hydro shall lead a collaborative process to develop a bill affordability program harmonized with Manitoba Hydro's other programs supporting low-income ratepayers. Manitoba Hydro shall file proposed Terms of Reference for this collaborative process with the Board (including proposed facilitators and stakeholder participants) by no later than October 31, 2015. If Terns of Reference cannot be agreed upon between Manitoba Hydro and participants, the Board is prepared to receive submissions and adjudicate the issue.

6. Manitoba Hydro shall consider additional measures to increase participation rates in the Affordable Energy Program and to assist all-electric customers, particularly those living in rural Manitoba and aboriginal communities without

9.0 Implementation

The Working Group recognizes and acknowledges that Manitoba Hydro rates fall within the domain of the Public Utilities Board and Manitoba Hydro. Given that some of the policy tools that would be most effective in addressing energy poverty would create corresponding costs for other users (i.e. rate increases), the Working Group acknowledges that decisions related to implementing the above recommendations fall outside the scope of its mandate. Costs for enhanced energy affordability programs (such as a Percentage of Income Payment Plan) could also be funded directly by government, but such decisions are also beyond the Working Group's mandated role. Manitoba Hydro has similarly advised the Working Group that recommendations presented in this report would be subject to approval by the Manitoba Hydro Energy Board prior to implementation. In light of these jurisdictional considerations, the Working Group agreed that a more detailed implementation plan would not be provided as part of the final report.

Manitoba Hydro has advised that it will review and evaluate the suite of recommended enhancements to existing energy affordability programs, and noted that any suggested changes would be subject to cost-effectiveness tests, executive approval, PUB orders and alignment with government policy.

Although the Working Group does not submit an implementation plan for the reasons cited above, it does note the benefit of further study of key issues related to energy affordability, both to support better understanding of this complex issue, and to improve the efficacy and impact of ongoing program enhancements.

Manitoba Hydro

Response to Recommendations of the Bill Affordability Working Group

The Bill Affordability Working Group identified a number of important findings in the Summary Report and Recommendations, dated January 2017. On page 33 of report, it states:

> *The Working Group's findings further illustrate the deeply complex, mult-faceted nature of energy poverty. Energy poverty spans issues of income, geography, cultural identity, family size, awareness of available support programs, and more. The Working Group's findings make it clear that no single initiative or program will solve the issue of energy poverty. Rather, the Working Group's recommendations reflect the consensus view that a suite or "toolkit" of improvements is required to improve energy affordability in the province.*

The following section describes each of the nine recommendations made by the Working Group and Manitoba Hydro's response and action to be undertaken with regards to each. Manitoba Hydro will be undertaking further assessments in response to recommendations of the Bill Affordability Working Group, where appropriate.

1. Low-Income Energy Efficiency and Weatherization Initiatives:

Recommendation – Maintain or enhance funding: Emphasis on existing Manitoba Hydro low-income energy-efficiency and weatherization initiatives be maintained at their current level, or enhanced with additional funding or programming where possible, whether those initiatives or funding are provided by Manitoba Hydro or otherwise.

Manitoba Hydro Response - Manitoba Hydro routinely investigates new technologies for incorporation into existing programs or the development of new programs to assist lower income customers. When strategic opportunities arise, such as ecoENERGY, Manitoba Hydro has leveraged these relationships to further promote energy efficiency upgrades.

Recommendation - Assess and enhance Furnace Replacement Program: Manitoba Hydro to assess the potential to modify the terms of the existing natural gas Furnace Replacement Program to include the replacement of mid-efficiency natural gas furnaces with high-efficiency natural gas furnaces for qualifying lower-income customers.

Manitoba Hydro Response - Manitoba Hydro has assessed the potential viability of replacing mid-efficiency natural gas furnaces with high-efficiency natural gas furnaces, assuming a customer co-payment of $9.50 per month over five years, consistent with the existing program. The estimated annual energy reductions and bill savings from the use of a high-efficiency natural gas furnace in place of a mid-efficiency natural gas furnace are less than the energy reductions and savings from replacing standard efficiency appliances with high efficiency appliances. Considering the cost of the high efficiency furnace installation, the modest energy consumption reduction combined with the relatively small bill reduction available to a participating customer, Manitoba Hydro does not recommend pursuing this change to the Furnace Replacement Program.

2. Electric Heating:

Recommendation - Explore fuel switching possibilities: Subject to evaluation against provincial and federal environmental climate policies, Manitoba Hydro to consider the development of incentive programs for qualifying lower-income customers to promote the replacement of residential electric heating systems with high-efficiency natural gas furnaces in areas where natural gas service is available, and to further explore the development of incentive programs to promote residential space heating conversions from electricity to biomass, geothermal or heat-pump technologies, if those programs are determined to be or can be made to be economically viable.

Manitoba Hydro Response - Manitoba Hydro anticipates that new Provincial climate change policy may be released in 2017 and will the Corporation will consider modifications to existing programs or additional program offerings after assessing the implications of any new policy direction.

3. Emergency Assistance:

Recommendation - Continue emergency assistance: Manitoba Hydro to continue to provide emergency assistance programming (e.g. Neighbours Helping Neighbours) and further evaluate: whether/how existing program meets the needs of low-income ratepayers; and whether Manitoba Hydro should better leverage partners (i.e. Salvation Army) and/or approach other organizations, including charitable/provincial/ federal partners, to consider greater collaboration and synergies.

Manitoba Hydro Response - Customers who have participated in the Neighbours Helping Neighbours (NHN) Program are assessed one year and two years after receiving assistance. Approximately 80% of those customers have lower or no arrears compared to when they needed emergency financial assistance. Manitoba Hydro will consult with Salvation Army regarding additional opportunities to leverage funds and seek other organizations that may wish to contribute to the continued success of NHN.

4. Landlord and Tenant Incentives:

Recommendation - Reduce barriers to landlord and tenant participation: Manitoba Hydro work with Employment and Income Assistance, the Residential Tenancies Branch, the Professional Property Management Association, the Winnipeg Rental Network, Manitoba Housing, All Aboard, First Nations, tribal councils, Manitoba Metis Federation, other Indigenous entities, neighborhood renewal organizations, the provincial government and other large lower-income housing providers to investigate opportunities to reduce barriers to landlord/tenant participation and/or increase landlord participation in affordable energy programs including energy-efficiency and weatherization initiatives.

Manitoba Hydro Response - Manitoba Hydro intends to form a Committee of interested parties in 2017 to coordinate efforts among the various groups to develop additional opportunities to increase participation in the landlord/tenant market.

5. Home Heating Bill Impacts Due To Extreme Weather:

Recommendation - Consider mitigation for extreme weather impacts: Manitoba Hydro to consider residential rate design options such as rate decoupling to mitigate the impact of colder-than-normal weather on monthly heating bills.

Manitoba Hydro Response: The evaluation of rate design alternatives involves the careful consideration of underlying rate making principals and goals, an understanding of the trade-offs that exist between individual rate making options, and an assessment of the benefits and disadvantages of those various options. Manitoba Hydro will assess the merits and shortcomings of options such as rate decoupling in conjunction with future examination of residential rate design options.

6. Equal Payment Plans:

Recommendation - Explore program enhancements: Manitoba Hydro to explore potential enhancements to existing Equal Payment Plan program to account for both arrears and projected bills, including consideration of the cost impacts and feasibility of administering those enhancements.

Recommendation - Educate and inform customers: Manitoba Hydro to explore what mechanisms or thresholds are needed to better educate and inform customers and the Public Utilities Board about eligibility for Equal Payment Plan program and how bills are adjusted and administered from year to year under the program.

Manitoba Hydro Response to both recommendations - Potential program enhancements have been examined and scoped. A preliminary program design has been concluded. Additional definition of program details is ongoing as is work to assess the program and administrative implications of the proposed enhancements. Once program enhancements are finalized, efforts will be undertaken to develop implementation details and a schedule will be determined as to when such enhancements may be introduced.

7. Bill Collection:

Recommendation - Continue to provide and improve customer service: Manitoba Hydro to maintain and continually strive towards providing respectful, helpful customer service to individuals in arrears, which includes ensuring staff are informed and able to communicate available programming to customers in a way that encourages those customers to ask questions and proactively deal with their payment issues or arrears.

Manitoba Hydro Response - Management in Credit and Recovery Services has incorporated bill affordability subject matter and specific processes for working with potential low income customers into regular ongoing department training efforts. Staff meet quarterly in small groups to receive training on emerging customer service issues. Low income topics were included in both the February and May training sessions and will continue to be included, as appropriate. Information about the Affordable Energy Program has also been included. Quality call monitoring which is done quarterly for each Credit Representative has included coaching on low income sensitivity.

8. Arrears Management and Bill Forgiveness:

Recommendation - Consider a bill payment/matching program: Manitoba Hydro to model and possibly pilot bill payment/matching program targeted to low-income individuals, which will include analysis of costs, benefits and impacts to Manitoba Hydro and consumers.

Manitoba Hydro Response – Manitoba Hydro will develop potential models in order to assess anticipated program effectiveness and costs in determining which option, if any, may be piloted.

9. Funding:

Recommendation - Consider government funding*: Government of Manitoba funding required for options recommended by the Bill Affordability Working Group be provided in accordance with the Public Utility Board's 2014 NFAT recommendation 12, i.e. that a portion of the incremental capital taxes and water rental fees from the development of the Keeyask Project be used to mitigate the impact of rate increases on lower-income consumers, northern and Aboriginal communities.

* Manitoba Hydro and Employment & Income Assistance abstained from providing consensus for this recommendation.

Manitoba Hydro Response - Manitoba Hydro notes the recommendation made by the PUB in its report to government arising from the 2014 NFAT review. Manitoba Hydro, at the time of the stakeholder engagement, abstained with regard to this recommendation (as did Employment & Income Assistance).

As noted on page 53 of Tab 2 of this filing, Manitoba Hydro is of the view that issues of poverty and distributional effects are complex and ought to be addressed through the setting of social policy which is within the purview of government. As such, Manitoba Hydro is of the view that of the provision of social assistance programs directed to low income customers is appropriately reserved for the Province of Manitoba.

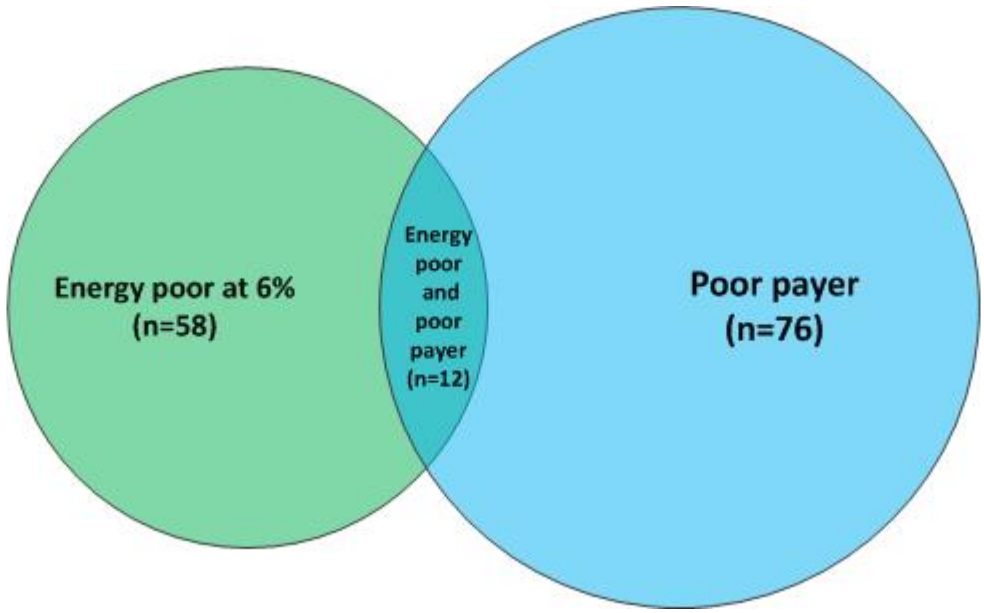


Figure 3: Energy poor and poor payer households – general sample

3.2.2 Energy poverty in the arrears subsample

Figure 4 provides the number of respondents from the customer survey that fall into each subgroup for the arrears subsample, using the LICO-125 household income threshold and the 10% and 6% energy burden thresholds to determine energy poor households. Of the 315 households in the arrears subsample who responded to the survey, 260 provided a response to survey questions about household income and the number of people in their household, *and* agreed to link their survey responses to Manitoba Hydro administrative data.

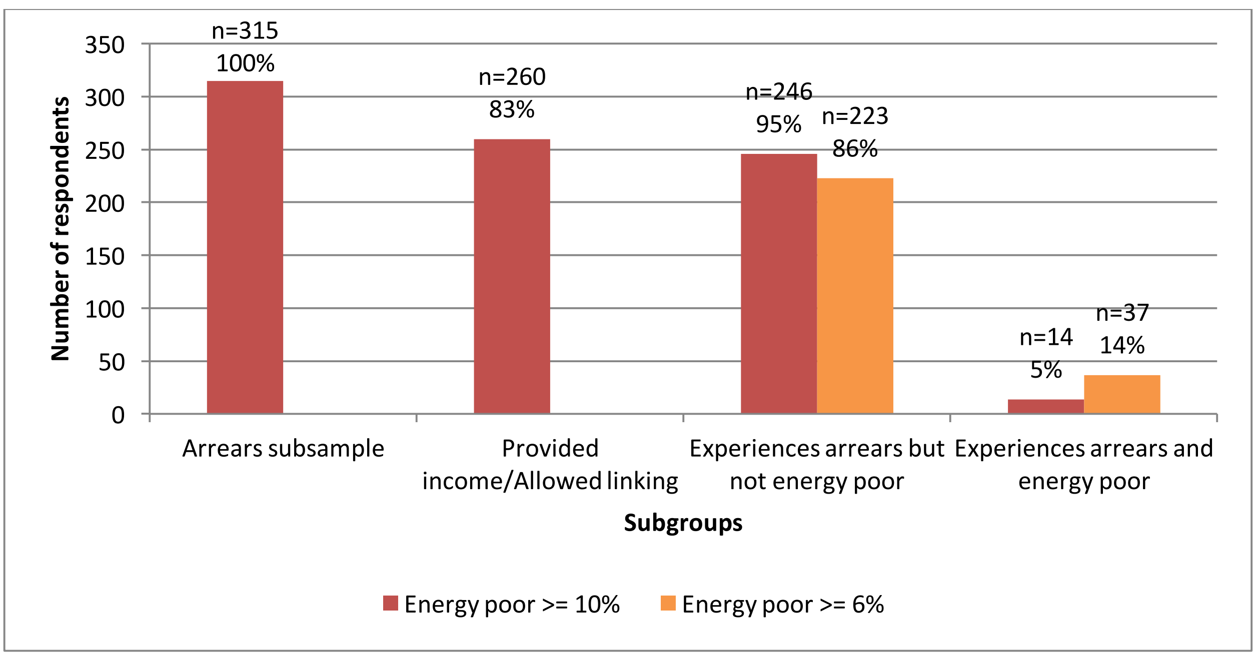


Figure 4: Subgroups within the arrears sample

Notably, most of the respondents in the arrears subsample are not energy poor at either the 10% level (95%) or the 6% level (86%).

Figure 5 further highlights the limited number of households in arrears that are energy poor at the 6% level.

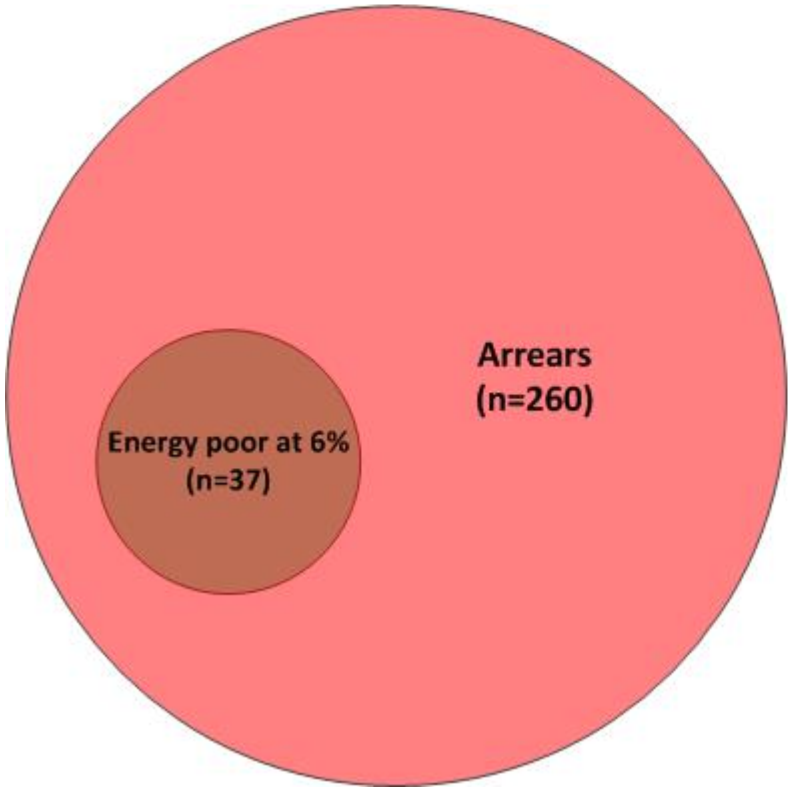


Figure 5: Energy poor within the arrears subsample

Furthermore, only a very small number of respondents who are energy poor at the 10% level fall into the subgroups of interest. As a result, sample sizes are insufficient for subdivided analyses. Therefore, only households that are energy poor at the 6% level are included in the analyses of the linked administrative and survey data in subsequent analyses presented in this report.

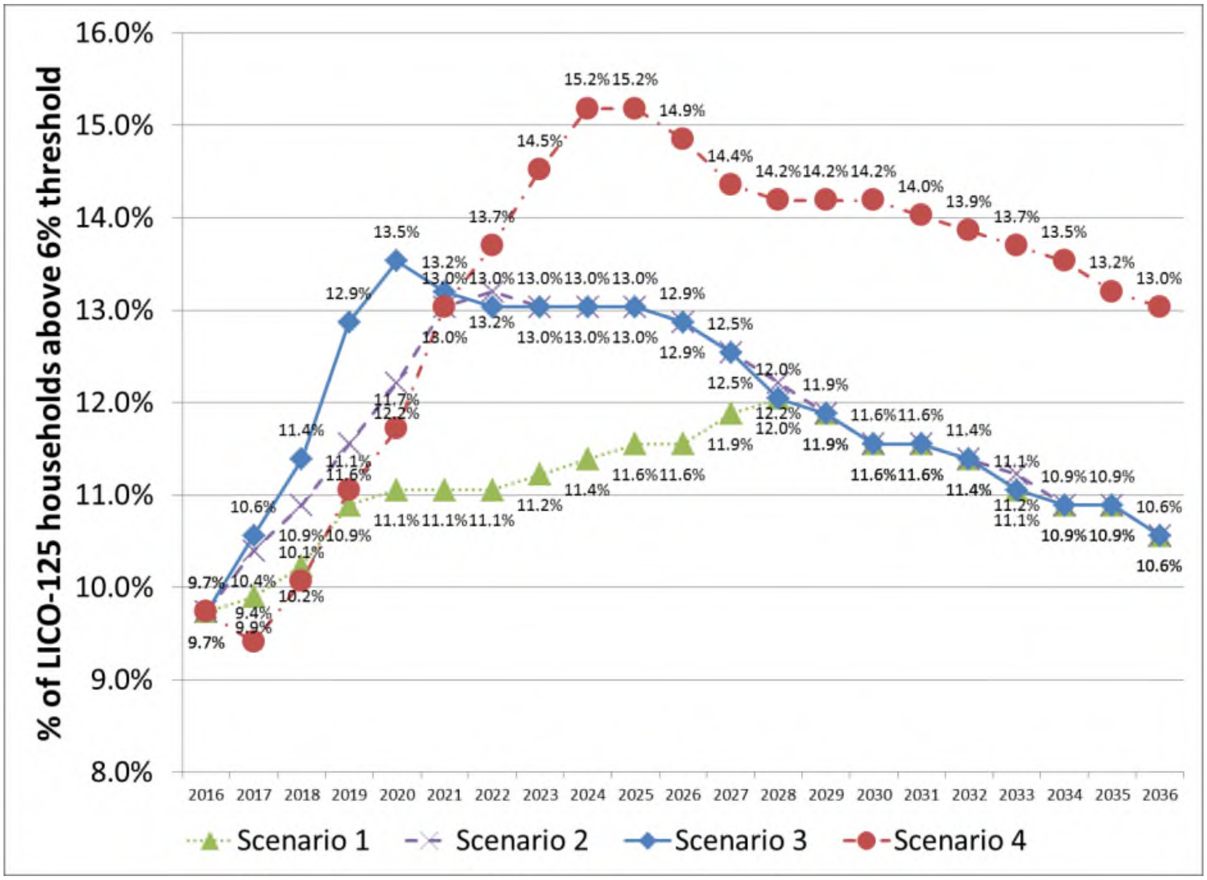


Figure 7: Impact of Manitoba Hydro rate increases on proportion of LICO-125 households above 6% energy poverty threshold, 2016–36, inclusive

Source: PRA calculations based on survey of Manitoba Hydro customers

Note: *Scenario 1*—3.95% nominal electricity rate increases for 12 years; *Scenario 2*—5.95% nominal electricity rate increases for 6 years; *Scenario 3*—7.95% nominal electricity rate increases for 4 years; *Scenario 4*—3.36% nominal electricity rate increase in 2017, followed by 7.9% rate increases for 6 years and a 4.54% rate increase for 1 year (assumed to come into effect on August 1st of each calendar year)

Similar results are observed when energy poverty is defined with reference to a 10% threshold. As Figure 8 suggests, the simulated impacts of rate increases on energy poverty tend to be less pronounced in the first, second and third scenarios than when the 6% threshold is employed, as are the differences between scenarios. As in Figure 7, beginning in the early-2020s, the fourth scenario is associated with substantially higher levels of energy poverty than the other scenarios; although energy poverty is projected to start leveling off later in the decade, it does not converge with the other scenarios prior to the end of the simulation horizon.

5.2 Estimated impact of bill affordability options on Manitoba Hydro and its customers

5.2.1 Impact on beneficiaries

Table 23: Impact of affordable rate design options upon the proportion of Manitoba Hydro customers experiencing energy poverty (2020)

Rate design option		6% threshold			10% threshold		
		Households experiencing energy poverty		% decline relative to no intervention	Households experiencing energy poverty		% decline relative to no intervention
		#	%		#	%	
No intervention		71	11.7%	N/A	22	3.6%	N/A
Straight rate discount	25%	34	5.6%	-52.1%	12	2.0%	-45.5%
	35%	24	4.0%	-66.2%	9	1.5%	-59.1%
	45%	21	3.5%	-70.4%	5	0.8%	-77.3%
Fixed charge waiver		63	10.4%	-11.3%	21	3.5%	-4.5%
Percentage of income payment plan (PIPP)		0	0.0%	-100.0%	0	0.0%	-100.0%

Source: PRA calculations based on survey of Manitoba Hydro customers

5.2.2 Impact on Manitoba Hydro revenues

Table 24: Estimated total revenue losses associated with energy affordability programs ($ millions) (2020)

Rate design option	Threshold	Source of lost revenue		
		Energy sales	Tax revenue*	Total
Straight rate discount (25%)	6%	$32.8	$4.7	$37.5
	10%	$10.9	$1.6	$12.5
Fixed charge waiver	6%	$13.1	$1.7	$14.8
	10%	$3.6	$0.5	$4.1
Percentage of Income Payment Plan (PIPP)	6%	$45.9	$6.5	$52.4
	10%	$17.2	$2.5	$19.7

* This refers to revenues lost as a consequence of reduced revenues from the sale of electricity and natural gas. For electricity, city and provincial taxes are 2.5% and 8.0%, respectively, while for natural gas, these are 2.5% and 1.4%, respectively; 5.0% GST is applied to both electricity and natural gas expenditures, as well as to the city tax (MB Hydro, 2016h).

Source: PRA calculations based on survey of Manitoba Hydro customers and MB Hydro (2016d)

Table 25: Estimated total electricity revenue losses associated with energy affordability programs ($ millions) (2020)				
Rate design option	Threshold	Source of lost revenue		
		Energy sales	Tax revenue*	Total
Straight rate discount (25%)	6%	$25.6	$4.0	$29.6
	10%	$9.1	$1.4	$10.6
Fixed charge waiver	6%	$7.6	$1.2	$8.8
	10%	$2.3	$0.4	$2.7
Percentage of Income Payment Plan (PIPP)	6%	$36.4	$5.7	$42.1
	10%	$14.1	$2.2	$16.3

* This refers to revenues lost as a consequence of reduced revenues from the sale of electricity. City and provincial taxes are 2.5% and 8.0%, respectively; furthermore, 5.0% GST is applied to electricity expenditures, as well as to the city tax (MB Hydro, 2016h).

Source: PRA calculations based on survey of Manitoba Hydro customers and MB Hydro (2016d)

Table 26: Estimated total natural gas revenue losses associated with energy affordability programs ($ millions) (2020)				
Rate design option	Threshold	Source of lost revenue		
		Energy sales	Tax revenue*	Total
Straight rate discount (25%)	6%	$7.2	$0.6	$7.8
	10%	$1.8	$0.2	$2.0
Fixed charge waiver	6%	$5.5	$0.5	$6.0
	10%	$1.3	$0.1	$1.4
Percentage of Income Payment Plan (PIPP)	6%	$9.5	$0.9	$10.3
	10%	$3.1	$0.3	$3.3

* This refers to revenues lost as a consequence of reduced revenues from the sale of natural gas. City and provincial taxes are 2.5% and 1.4%, respectively; furthermore, 5.0% GST is applied to natural gas expenditures, as well as to the city tax (MB Hydro, 2016h).

Source: PRA calculations based on survey of Manitoba Hydro customers and MB Hydro (2016d)

5.2.3 Impact on non-beneficiaries

Table 27: Electricity rate increases required from residential ratepayers to recover revenues lost as a consequence of affordable rate design (per kWh) (2020)

Rate design option	Threshold	Source of lost revenue		
		Energy sales	Tax revenue*	Total
Straight rate discount (25%)	6%	\$0.0042	\$0.0007	\$0.0049
	10%	\$0.0014	\$0.0002	\$0.0016
Fixed charge waiver	6%	\$0.0013	\$0.0002	\$0.0015
	10%	\$0.0004	\$0.0001	\$0.0004
Percentage of Income Payment Plan (PIPP)	6%	\$0.0060	\$0.0009	\$0.0070
	10%	\$0.0022	\$0.0003	\$0.0025

* This refers to revenues lost as a consequence of reduced revenues from the sale of electricity and natural gas. For electricity, city and provincial taxes are 2.5% and 8.0%, respectively, while for natural gas, these are 2.5% and 1.4%, respectively; 5.0% GST is applied to both electricity and natural gas expenditures, as well as to the city tax (MB Hydro, 2016h).

Source: PRA calculations based on survey of Manitoba Hydro customers

Table 28: Natural gas rate increases required from residential ratepayers to recover revenues lost as a consequence of affordable rate design (per m^3) (2020)

Rate design option	Threshold	Source of lost revenue		
		Energy sales	Tax revenue*	Total
Straight rate discount (25%)	6%	\$0.0126	\$0.0011	\$0.0137
	10%	\$0.0030	\$0.0003	\$0.0033
Fixed charge waiver	6%	\$0.0096	\$0.0009	\$0.0105
	10%	\$0.0021	\$0.0002	\$0.0023
Percentage of Income Payment Plan (PIPP)	6%	\$0.0166	\$0.0015	\$0.0181
	10%	\$0.0051	\$0.0005	\$0.0055

* This refers to revenues lost as a consequence of reduced revenues from the sale of electricity and natural gas. For electricity, city and provincial taxes are 2.5% and 8.0%, respectively, while for natural gas, these are 2.5% and 1.4%, respectively; 5.0% GST is applied to both electricity and natural gas expenditures, as well as to the city tax (MB Hydro, 2016h).

Source: PRA calculations based on survey of Manitoba Hydro customers

Summary of Estimated Impacts of PRA Modelled Options on Manitoba Hydro and its Customers

	% Reduction in Energy Poverty		MH Lost Electric Revenues ($M)		Electric Rate Impact *	
	6% Thresh.	10% Thresh.	6% Thresh.	10% Thresh.	6% Thresh.	10% Thresh.
Fixed Monthly Charge Waiver	-11%	-5%	$7.6	$2.3	0.15 ¢/kWh	0.04 ¢/kWh
Straight Rate Discount (25%)	-52%	-46%	$25.6	$9.1	0.49 ¢/kWh	0.16 ¢/kWh
Percentage of Income Payment Plan	-100%	-100%	$36.4	$14.1	0.70 ¢/kWh	0.25 ¢/kWh

** Impact assumes Aug. 1/17 rates, includes the recovery of lost electric sales and tax revenues, and that lost revenues are only recovered from non-energy poor residential customers.*

Source: MH 2017/18 & 2018/19 GRA Information Request AMC/MH II-23a-c pp. 11-13 (Tables 23, 25, and 27)

Households in arrears

Manitoba Hydro data indicates that approximately 12% of residential accounts were in arrears (had unpaid bills) in 2015. Of these, 6% were 60 days or more in arrears and 3% were 90 days or more in arrears. Arrears tend to peak in late winter/early spring each year. Payment issues are substantially more widespread among rural and northern customers, as well as for electrically heated households.

Payment issues in First Nations communities are especially pronounced. Households in those communities (defined in this case to include on-reserve accounts with treaty numbers) make up just 3% of all Manitoba Hydro customers, yet account for over half of all payments that are outstanding at any given time. Interviews with First Nations community representatives and a review of the available documentation suggest these issues stem from a range of administrative factors, such as a lack of understanding about who is responsible for paying energy bills and poor synchronization or management of transfer payments, as well as structural factors, such as climatic conditions, a lack of access to natural gas, poor quality and/or deteriorating housing stock, federal policies regarding coverage of electricity costs associated with non-residential accounts in these communities, and insufficient incentives to conserve energy.

Collection costs related to arrears

In 2015 the total cost of collections to Manitoba Hydro was approximately $14.2 million, consisting of $9.5 million in collection expenses and $4.6 million in bad debt write-offs. Over three-quarters of total costs were from credit and collection activity associated with electricity provided by Hydro (as opposed to natural gas). Analysis of year-over-year growth in credit and collection costs indicate these increased significantly in 2015 after having generally declined for several years. The increase in overall expenses appears to be because of the growth in bad debt expenses on the electricity side, which increased nearly 85% between 2014 and 2015.

Disconnections

Similar to arrears, the number of service disconnections by Manitoba Hydro due to non-payment exhibits substantial seasonality, which is likely attributable in part to the utility's moratorium on winter disconnections for most residential customers. In 2014, urban, rural, and northern customers accounted for 47%, 36%, and 18% of all disconnects; such service terminations fall disproportionately on First Nations customers who experienced 22% of all disconnects in the same year. Data from 2012 to 2014 suggests sizable increases in disconnections among all customer segments over that interval.

Relationship between energy poverty and arrears

The Working Group and PRA examined the relationship between income, arrears and energy poverty. To date, little research has been conducted on these relationships, and a key aim of the Working Group was to gather better data on how strongly low household income, unpaid bills and energy poverty were linked.

REFERENCE:

Appendix 10.5, 5.2, Page 16 of 242

PREAMBLE TO IR (IF ANY):

Manitoba Hydro's 2014 Residential Energy Use Survey (REUS) indicates that approximately 14% of Manitoba households spend 6% or more of their total income on energy bills, while about 4.2% of households spend more than 10% of their income. High energy burdens are much more prevalent among LICO-125 households; for example, whereas only 0.2% of non-LICO-125 households allocated 10% or more of their income to energy in 2014, this was true of 13.5% of their energy-poor counterparts. The REUS also suggests that energy poverty is greater among customers who identify as Indigenous (i.e. of First Nations, Metis or Inuit ancestry), customers with older homes and/or homes that are electrically heated, and households with either a single member or five or more members.

QUESTION:

Please provide a copy of the 2014 REUS.

Based on the 2014 REUS or other sources,

a) please indicate the percentage of on-reserve First Nations households that:
   i. Spend 6% or more of their total income on energy bills, and
   ii. Spend 10% or more of their total income on energy bills;
b) please indicate the percentage of on-reserve First Nations households that are LICO-125 households;
c) please indicate the percentages of LICO-125 and non-LICO-125 on-reserve First Nations households that:
   i. Spend 6% or more of their total income on energy bills, and
   ii. Spend 10% or more of their total income on energy bills.

If MH does not have sufficient data to respond to this questions, please:

a) Respond to the extent possible based on the information available,

b) Describe in detail the available data, and
c) Provide copies of any other relevant documents

RATIONALE FOR QUESTION:

RESPONSE:

A copy of the 2014 Residential Energy Use Survey is provided as an attachment to PUB/MH I-125a.

a) Based on the 2014 Residential Energy Use Survey:
   i. 49.0% of on-reserve First Nations customers spend 6% or more of their total annual household income on electricity bills; and,
   ii. 34.4% of on-reserve First Nations customers spend 10% or more of their total annual household income on electricity bills.

b) Based on the 2014 Residential Energy Use Survey, 64.8% of on-reserve First Nations customers are defined as LICO-125.

c) Based on the 2014 Residential Energy Use Survey:
   i. 66.5% of on-reserve LICO-125 and 16.7% of on-reserve non-LICO-125 First Nations customers spend 6% or more of their total annual household income on electricity bills; and,
   ii. 53.0% of on-reserve LICO-125 and 0% of on-reserve non-LICO-125 First Nations customers spend 10% or more of their total annual household income on electricity bills.

117

The present standard rate design of a single Energy Charge and a single Demand Charge is proposed for rates effective August 1, 2017 and April 1, 2018, both increasing by 7.9% each year as shown in **Figure 9.3**.

Figure 9.3 Energy and Demand Charges for General Service Large

	August 1, 2017		April 1, 2018	
Large Sub-Class	**Energy Charge**	**Demand Charge**	**Energy Charge**	**Demand Charge**
Large 750-30 kV	$0.03873	$8.94	$0.04179	$9.65
Large 30-100 kV	$0.03600	$7.66	$0.03884	$8.27
Large >100 kV	$0.03488	$6.82	$0.03764	$7.36

As the rate increases are being applied equally to both the Energy and Demand Charges, the bill impacts for all customers will be generally the same regardless of load factor.

9.3.5 Area and Roadway Lighting

Manitoba Hydro is proposing to apply the 7.9% rate increase to the Area and Roadway Lighting class for each of the two fiscal years. In addition, Manitoba Hydro is proposing two new LED rates for Outdoor Lighting and four new LED rates for Sentinel Lighting. Two existing rates – Festoon Lighting and Christmas Lighting - no longer have customers billing on them and are not available for new services, therefore have been removed from the rate schedules.

The new Outdoor Lighting rates are for the 150 W LED street lights where there are two lights on a hundred foot pole and four lights on a hundred foot pole. As part of the LED street light conversion, 400W HPS lights were being converted to 250 W LED lights which ranged in wattage from 180 watts to 280 watts. A new inventory of LED lights now allows existing 400W HPS lights to be replaced with 150W LED lights which range in wattage from 120 watts to 180 watts. Since there was no rates associated with the 150W LED lights on a hundred foot pole, the two new rates had to be added.

The four new proposed Sentinel LED rates have been added to account for new installations and/or Sentinel HPS lights which are now being converted to LED. The existing 100 and 150 watt HPS lights are being replaced with 60 and 90 watt LED lights.

The monthly rates for the LED Sentinel rentals will be the same rates as charged for the HPS and MV rentals, as the energy portion for these lights is metered and therefore not included in the flat rate charge.

9.3.6 Limited Use of Billing Demand ("LUBD") Rate Option

There are approximately 70 General Service customers currently on the LUBD Rate Option.

The LUBD rate structure was introduced in 2000 to address the high unit energy costs faced by a relatively small number of General Service customers who operate with very low load factors. These customers, who set high demands relative to their overall energy use, would normally face high demand charges even though they consumed relatively little energy. Under the LUBD rate option, customers opt for a rate structure which has a lower demand charge but recovers the required revenues through a higher energy charge.

The LUBD rate was designed such that demand billed customers would be indifferent at a billing load factor of 18% between this rate and the standard General Service rate for which they otherwise qualify. By paying a higher energy charge in exchange for a lower demand charge, customers with billing load factors less than 18% may benefit from lower monthly bills compared to accepting service at standard General Service rates.

There is no difference in the level of the Basic Charge or the determination of the Billing Demand when customers choose LUBD over standard rates.

The rates proposed for LUBD customers are derived from the rates proposed for General Service Small, Medium and Large customer classes. The monthly Basic Charge will increase to the same level as regular General Service Small/Medium customers. The Demand Charge is set at approximately 25% of the Demand Charge of the corresponding regular General Service class, with the energy charge calculated to provide revenue neutrality at a load factor of approximately 18%.

Manitoba Hydro prepares annual reports to the PUB on the LUBD rate option, and reports covering the period April 1, 2015 to March 31, 2016, and April 1, 2014 to March 31, 2015, can be found as Appendix 9.7.

9.3.7 Flat Rate Water Heating ("FRWH")

There are approximately 3,300 Residential FRWH customers and approximately 350 General Service with Flat Rate Water Heating service.

These customers have unmetered electrical service to supply energy to their electric water heater in their home or business. The number of customers on FRWH is generally declining by approximately 5% per year.

Manitoba Hydro proposes to apply the 7.9% rate increases to the current monthly rate for both Residential and General Service FRWH customers.

9.4 ALTERNATIVE RATE PROGRAMS

9.4.1 Surplus Energy Program ("SEP")

There are approximately 30 General Service customers participating in the Surplus Energy Program.

The Surplus Energy Program is a rate program that enables a qualifying customer to purchase surplus energy at market prices that are determined on a weekly basis for peak, shoulder, and off-peak periods. Manitoba Hydro files for SEP rate approvals with the PUB on a weekly basis, for rates to be set for the following week.

Manitoba Hydro is seeking final confirmation of the rate approval process given the proposed change to the Terms and Conditions for SEP Option 1 which was proposed in the 2012/13 and 2013/14 General Rate Application, and approved on an interim basis in Order 43/13.

The change proposed for Option 1 would be to allow customers to have a different Reference Demand for each of the three pricing periods. The highest designated Reference Demand would be used in determining the customer's monthly billed

178

demand. The change would allow eligible General Service industrial customers to nominate different levels of Surplus Energy Program energy purchases in peak periods (5x8 weekdays – day time), off-peak periods (7x8 weekdays – night time), and shoulder periods (other weekday or weekend periods). These changes would allow customers to tailor their Option 1 purchases to minimize costs and/or maximize purchase effectiveness.

Manitoba Hydro is requesting the changes to SEP Option 1 be approved as final. While there are currently no customers on Option 1, this change would open the possibility for customers to consider this Option in the future.

A copy of the amended SEP Terms and Conditions are included in Appendix 9.8.

Manitoba Hydro files an annual report with the PUB on the status of the SEP. Copies of the reports covering the period November 1, 2015 to October 31, 2016 and November 1, 2014 to October 31, 2015 can be found in Appendix 9.9.

Manitoba Hydro also files quarterly reports with the PUB on the factors influencing SEP pricing. Copies of the quarterly reports filed from the period August 1, 2015 to April 30, 2017 are included as Appendix 9.10.

9.4.2 Curtailable Rate Program ("CRP")

There are currently three General Service Large customers participating in the Curtailable Rates Program.

The Curtailable Rate Program is not a rate class, rather it is an optional program through which Manitoba Hydro may call on participating customers to curtail a portion of their load to assist in maintaining operating and contingency reserves in the event of loss of generation or transmission.

Manitoba Hydro is not seeking any changes to the CRP. All changes previously approved as final in Order 73/15 have been implemented. Manitoba Hydro is providing as Appendix 9.11 copy of the CRP Terms and Conditions reflecting the approved and implemented modifications to the CRP.

Manitoba Hydro files an annual report with the PUB on the status of the CRP. Copies of the reports covering the period April 1, 2016 to March 31, 2017, April 1, 2015 to March 31, 2016 and April 1, 2014 to March 31, 2015,can be found in Appendix 9.12.

9.5 COMPARISON OF ELECTRICITY RATES ACROSS JURISDICTIONS

Figure 9.4 below provides a comparison of the rate increases approved and proposed by other Canadian electric utilities since 2007.

Order No.	Date	Curtailable Rates Program
54/16	April 26, 2016	Approval of the Curtailable Rate Program Reference Discount Effective April 1, 2016
45/17	April 27, 2017	Approval of the Curtailable Rate Program Reference Discount Effective April 1, 2017

Order No.	Date	General Consumer Rates
79/14	July 15, 2014	Approval for New Light Emitting Diode (LED) rates for Area and Roadway Lighting Class Effective August 1, 2014
59/16	April 28, 2016	Order in Respect of an Application by Manitoba Hydro for April 1, 2016 Interim Rates
68/16	May 17, 2016	Approval of August 1, 2016 Rate Schedules flowing from Order 59/16

Order No.	Date	Remote Communities Served by Diesel Generation
17/04	February 6, 2004	Increase in Electric Rates in Remote Communities Served by Diesel Generation
46/04	March 25, 2004	Increases in Electric Rates in Remote Communities Served by Diesel Generation resulting from Order 17/04
159/04	December 22, 2004	New Electricity Rates in Remote Communities Served by Diesel Generation
176/06	December 21, 2006	New Electricity Rates in Remote Communities Served by Diesel Generation
1/10	January 5, 2010	Review of Issues Related to Current Electricity Rates Charged in Remote Communities Served by Diesel Generation
134/10	December 22, 2010	Increase in Electric Rates in Remote Communities Served by Diesel Generation
1/11	January 4, 2011	New Electricity Rates in Remote Communities Served by Diesel Generation Effective January 1, 2011 to December 31, 2011 flowing from Order 134/10
148/11	October 20, 2011	Removal of the Residential Tail Block Effective November 1, 2011
116/12	August 29, 2012	Approval for September 1, 2012, 6.5% increase to full cost portion of the General Service and Government rates in the four remote communities served by diesel generation
117/12	August 31, 2102	Approval of September 1, 2012 Rate Schedules flowing from Order 116/12

Order No.	Date	Surplus Energy Program
43/13	April 26, 2013	Approval of Surplus Energy Program Option 1 Terms and Conditions
76/15	July 29, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
79/15	August 6, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
82/15	August 12, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
85/15	August 19, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
86/15	August 26, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
87/15	September 2, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
88/15	September 9, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
89/15	September 16, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
91/15	September 23, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
93/15	September 30, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
99/15	October 7, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
100/15	October 14, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1

Order No.	Date	Surplus Energy Program
104/15	October 21, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
105/15	October 28, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
111/15	November 4, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
113/15	November 10, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
116/15	November 18, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
122/15	November 25, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
134/15	December 2, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
135/15	December 9, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
138/15	December 16, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
143/15	December 23, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
145/15	December 30, 2015	Approval for Surplus Energy Program Rates, Schedule SEP-1
2/16	January 6, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
6/16	January 13, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
10/16	January 20, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
13/16	January 27, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
19/16	February 3, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
20/16	February 10, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
22/16	February 17, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
25/16	February 24, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
29/16	March 2, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
32/16	March 9, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
35/16	March 16, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
42/16	March 23, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
44/16	March 30, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
47/16	April 6, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
50/16	April 13, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
51/16	April 20, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
58/16	April 27, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
62/16	May 4, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
66/16	May 11, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
67/16	May 18, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
69/16	May 25, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
70/16	June 1, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
73/16	June 8, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
77/16	June 15, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
80/16	June 22, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
81/16	June 29, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
82/16	July 6, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
87/16	July 13, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
92/16	July 20, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1

Order No.	Date	Surplus Energy Program
101/16	July 27, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
103/16	August 3, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
109/16	August 10, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
110/16	August 17, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
112/16	August 24, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
113/16	August 31, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
116/16	September 7, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
118/16	September 14, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
119/16	September 21, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
124/16	September 28, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
126/16	October 5, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
129/16	October 12, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
133/16	October 19, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
138/16	October 26, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
140/16	November 2, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
141/16	November 9, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
143/16	November 16, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
144/16	November 23, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
150/16	November 30, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
152/16	December 7, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
161/16	December 14, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
165/16	December 21, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
166/16	December 28, 2016	Approval for Surplus Energy Program Rates, Schedule SEP-1
1/17	January 4, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
2/17	January 11, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
4/17	January 18, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
9/17	January 25, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
11/17	February 1, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
17/17	February 8, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
22/17	February 15, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
24/17	February 22, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
27/17	March 1, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
29/17	March 8, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
30/17	March 15, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
31/17	March 22, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
34/17	March 29, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
36/17	April 5, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
38/17	April 12, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
41/17	April 19, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
42/17	April 26, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1

Order No.	Date	Surplus Energy Program
47/17	May 3, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1
48/17	May 10, 2017	Approval for Surplus Energy Program Rates, Schedule SEP-1

PROPOSED

RATE SCHEDULES

TO BE EFFECTIVE

APRIL 1, 2016

Manitoba Hydro

AREA AND ROADWAY LIGHTING

FESTOON LIGHTING - *TARIFF NO. 2016-84*

Connected load @ $0.942/ kW per night of scheduled use:

Minimum Monthly Bill: $ 19.23

Applicability:

The Festoon Lighting rate is applicable only for existing unmetered municipally-owned festoon light strings suspended across streets and public thoroughfares. The customer is required to advise the Corporation prior to any changes in the nights contract for operation and/or the connected lighting kilowatts.

DECORATIVE LIGHTING - *TARIFF NO. 2016-85*

Connected load @ $0.942/kW per night of scheduled use:

Minimum Monthly Bill: $ 19.23

Applicability:

The Decorative Lighting rate is applicable for new and existing unmetered municipally-owned decorative lights on frames or modules mounted on roadway lighting poles or ornamental standards and/or Christmas trees. The customer is required to advise the Corporation prior to any change in the nights contracted for operation and\or the connected lighting kilowatts.

CHRISTMAS LIGHTING - *TARIFF NO. 2016-86*

Connected load @ $0.0752/ kWh.

Applicability:

The Christmas Lighting rate is applicable to the City of Winnipeg Christmas lighting only. The customer is required to advise the Corporation prior to any change in the connected load.