MANITOBA HYDRO

2017/18 & 2018/19 GENERAL RATE APPLICATION

COST OF SERVICE AND LOAD RESEARCH

INDEX

Appendices

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COST OF SERVICE AND LOAD RESEARCH

8.0 OVERVIEW

Tab 8 discusses Manitoba Hydro's Cost of Service Study Methodology and PCOSS18. Section 8.1 discusses the purpose of a Cost of Service Study and methodology used in PCOSS18; Section 8.2 provides an overview of the Cost of Service process; Section 8.3 describes the inputs used in the study; Section 8.4 provides the PCOSS18 results which reflect direction flowing from Order 164/16; Section 8.5 discusses the role of Cost of Service in setting rates; and Section 8.6 provides an overview of the 2014/15 electric Load Research results.

8.1 PURPOSE OF A COST OF SERVICE STUDY

The COS determines each customer class's share of the Corporation's overall revenue requirement, the primary objective of which is to determine fair and realistic cost recognition for domestic customers used in the determination of rates.

The development of utility rates follows three sequential steps:

Figure 8.1 Sequential Steps for the Development of Utility Rates

Revenue Requirement	•Determination of overall cost of providing service: •Operating and Adminstrative •Finance expense •Depreciation and amortization •Capital and other taxes •Fuel and power purchases •Water rentals and assessments •Contribution to reserves (net income)
Cost of Service	•Determination of a fair allocation of the Corporation's overall revenue requirement to each customer class based on how customers cause costs to be incurred
Rate Design	•Determination of how to recover each class' revenue requirement

Manitoba Hydro’s COS Study is an embedded cost study in that it is based on forecast financial costs for a single test year period from the Integrated Financial Forecast (“IFF”). Manitoba Hydro utilizes net plant investment for the purpose of allocating revenue requirement items such as finance expense, capital taxes, and the required contributions to financial reserves. O&A and depreciation is forecast by facility or service so it can then be allocated amongst the customer classes.

The results of the study indicate the degree to which each rate class’s allocated costs are being recovered through revenues collected from the class. The ratio of class revenues and costs is referred to as Revenue Cost Coverage (“RCC”). Although the study has the appearance of exactness, it provides a reasonable estimate of the costs to serve each class. To recognize this Manitoba Hydro, similar to other utilities in Canada, uses a Zone of Reasonableness in rate setting. In Manitoba, to the extent that a customer class’s RCC falls in a range of 95% to 105%, it is accepted that its revenues are recovering the allocated cost. The matter of appropriate reliance on Cost of Service, including the target Zone of Reasonableness range is discussed further in this Tab, Section 8.5.

Manitoba Hydro's Cost of Service Methodology has been reviewed on numerous occasions before the Public Utilities Board previously and most recently in 2016 which culminated through Order 164/16 issued on December 20, 2016. PCOSS18, based on the 2017/18 rate setting period flowing from IFF16, is the first cost analysis undertaken by Manitoba Hydro since 2012 and reflects the methodology changes directed in Order 164/16. Additionally, since the preparation of PCOSS14, reflecting IFF12, a number of events have occurred. These include the confirmation of large planned additions to generation investment, the adoption of International Financial Reporting Standards ("IFRS"), asset additions, and a requirement for greater levels of net income as significant additions are made to assets in-service. While many of these matters that have been discussed extensively with PUB in past proceedings, this is the first time they have been reflected in MH's COSS.

Both Keeyask and BPIII currently under construction and not yet in-service are not reflected in PCOSS18. It is anticipated these changes will result in variability in class cost responsibility in future Cost of Service Studies.

8.1.1 PCOSS18 Methodology – Order 164/16

In response to Order 164/16, Manitoba Hydro filed an updated PCOSS14 on February 21, 2017 to reflect directives contained in that Order summarized as follows:

- Elimination of the Export Class
- Allocation of Net Export Revenue (NER) to domestic classes based on their allocation of Generation and Transmission costs
- Elimination of the Uniform Rate Adjustment
- Generation costs classified to Energy and Demand based on System Load Factor
- US Interconnections classified to Energy and Demand based on System Load Factor
- Un-weighted Energy used to allocate Energy-related costs of Generation and Transmission
- Winter Coincident Peak used to allocate Demand costs of the Generation, Transmission and Subtransmission functions
- Distribution Poles and Wires classified as 100% Demand

PCOSS18 continues to reflect the methodology directed in Order 164/16. While Manitoba Hydro has not made substantial changes in methodology in PCOSS18, several allocations have been reviewed consistent with the PUB's direction flowing from Order 164/16 and its correspondence of April 3, 2017 as follows:

- Allocation of MISO Fees (Section 8.2.1)
- Functionalization of SCADA Costs (Section 8.2.1)
- Common Costs (Section 8.2.1)
- Allocation of Billings, Collections, Meter Reading, Meter Investment, Electrical Inspections and Customer Service general costs (Section 8.2.3)

8.2 COST OF SERVICE PROCESS OVERVIEW

The cost allocation process is a three step sequential process consisting of functionalizing, classifying, and allocating all the costs that make up the Corporation's annual revenue requirement. This section provides a discussion of Manitoba Hydro's Cost of Service process and treatment of facilities and related costs.

8.2.1 Functionalization

Functionalization is the preliminary arrangement of costs according to functions performed by the electric system. The primary purpose of the functionalization process is to allocate to each customer class only those functions used in providing service.

The study functionalizes utility costs into five main groups: Generation; Transmission; Subtransmission; Distribution Plant and Distribution Services (or Customer Service). These functions are consistent with direction in Order 164/16 and largely consistent with past Manitoba Hydro cost of service practice:

Generation Function

The Generation Function includes all generating facilities, wind and import purchases, fuel, water rentals, generation-related transmission including all HVDC facilities (Henday, Radisson, and Bipoles), the costs associated with Demand Side Management, as well as a share of the communication facilities, buildings and general equipment. HVDC converter facilities at Dorsey are now also included confirmed in Order 164/16.

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.

Transmission Function

The Transmission function includes all high voltage (100 kV and higher) transmission lines except generation-outlet transmission included in the Generation function. The function also includes the high voltage portion of substations, and a share of the communication facilities, buildings, general equipment and substation transformers in stock. As noted above, the portion of MISO fees related to Transmission services are also functionalized as Transmission.

Substation facilities may be functionalized as entirely Transmission, Subtransmission or Distribution-related, or may be considered multifunction facilities that can support Transmission as well as Sub-Transmission and/or Distribution. For those multifunction facilities, an analysis of voltage levels, functions, current use, and cost data, is used to derive the functionalization split between Transmission, Subtransmission and/or Distribution.

Subtransmission Function

This function includes investment costs associated with lower voltage (66 kV and 33 kV) subtransmission lines, the low voltage portion of substations and a share of communication equipment, buildings, general equipment, and substation transformers in stock.

Distribution Plant Function

This function includes the low voltage (less than 33 kV) distribution lines, the low voltage portion of substations, meters, metering transformers, distribution transformers and a share of communication equipment, buildings, general equipment, and substation transformers in stock. Distribution Plant is further sub-functionalized into Substations, Transformers, Poles & Wires, Services, and Meters.

Distribution Services Function

A Distribution Services category is treated as a separate primary function not combined with Distribution Plant. It includes all the costs incurred by Manitoba Hydro in servicing the customer after delivery of the energy, such as billing and collections, meter reading and general customer service costs. In addition, it includes a share of buildings and general equipment associated with these activities.

As part of the review and update of customer weighting factors discussed in Section 8.2.3, Manitoba Hydro has in effect sub-functionalized these services within this function such that those customer classes provided the services are allocated the related costs. This includes activities and costs associated with billing, collections, meter reading, and inspections.

Common Costs/General Plant

Common costs relate to activities and investments that support all of Manitoba Hydro's functions. This includes administration and general costs such Accounting, Human Resources, Legal, and Information Technology labour. Examples of investment-related common costs (general plant) include personal computers and other IT infrastructure, buildings, construction equipment, vehicles, and furniture.

Because these investments and operating costs support all functions, these costs are functionalized on the basis of labour costs. While there are two mechanisms by which this is accomplished in Cost of Service, these costs are all functionalized on the basis of labour costs. The operating costs are functionalized directly in Manitoba Hydro's accounting system (SAP) through approximately 400 settlement cost centers in proportion to labour planned and directly charged to these settlement cost centers. Depreciation expense and investment associated with general plant is functionalized within Cost of Service, proportional to total functionalized operating costs that flows from SAP (excluding water rentals, fuel and purchased power) thus in proportion to labour costs. Additionally, in PCOSS18, all common costs have been prorated within a function on the basis of cost of each sub-function as directed in Order 164/16 (page 91) as shown in Schedule 4.1.

Communication equipment, including the EMS/SCADA system, is also part of common costs. Communication operating costs, depreciation and investment, excluding the EMS/SCADA portion, are all functionalized within the Cost of Service in proportion to labour costs.

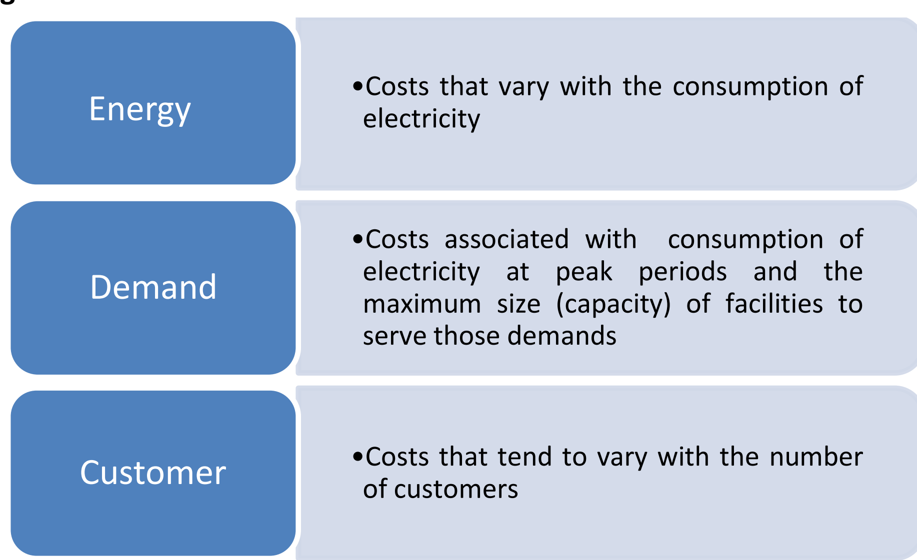
Manitoba Hydro previously functionalized the EMS/SCADA portion of Communication costs between Generation, Transmission and Subtransmission on a 36/28/36% basis.

The EMS/SCADA system includes hardware, software and associated equipment that provide real time monitoring and control of Manitoba Hydro's electrical system. As part of PCOSS18 and as directed in Order 164/16, Manitoba Hydro has reviewed this treatment. Manitoba Hydro has now functionalized these costs to Generation, Transmission, Subtransmission and Distribution on a 16/52/4/29% basis, the details of which are provided in Schedule 4.8. The updated allocator is based on the total number of remote terminal units installed by function. Since remote terminal units are the interface that actually allow the utility to remotely view and control the overall power system, their quantity and location provides a reasonable basis of functionalizing total EMS/SCADA costs.

8.2.2 Classification

Once costs are functionalized, they are classified according to the system design and operating characteristics that cause the costs to be incurred. These classifications are based on measurable billing determinants (cost drivers); Energy, Demand and Customers

Figure 8.2 Classification



Costs that have been functionalized and classified by cost component are then allocated to customer rate classes on the basis of amount of energy, demand and number of customers. This process also enables the determination of unit demand, energy and customer costs for each customer class.

As a result of Order 164/16, there were fundamental and significant changes in the classification of costs. Manitoba Hydro reflected these changes in its Submission flowing from Order 164/16 dated February 21, 2017. Manitoba Hydro has not made any changes to the approach to classification in PCOSS18.

Generation costs, excluding water rentals, variable hydraulic operating and maintenance costs and wind have been classified as Energy and Demand based on System Load Factor. Order 164/16 also directed that the costs of DSM activities no longer be allocated to customer classes based on their participation but rather treated as a generation resource classified on the basis of System Load Factor. PCOSS18 reflects this directed treatment.

Consistent with its Submission flowing from Order 164/16 the System Load Factor in PCOSS18 has been derived on the basis of the average of eight years of historic domestic load factors shown in **Figure 8.3**. Use of eight years is consistent with the approach used to estimate class demand in the PCOSS. The result is that 62.0% of these Generation-related costs are classified as Energy, and the remaining 38.0% as Demand:

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;

- Distribution plant costs are classified as either Customer or Demand related summarized in **Figure 8.4**.

Figure 8.4 Classification of Distribution Plant

	COST CLASSIFICATION	
DISTRIBUTION FACILITIES	DEMAND	CUSTOMER
Substation	100%	
Line Transformers	100%	
Pole, Wire and Related Facilities	100%	
Meters and Metering Transformers		100%
Service Drops		100%

8.2.3 Allocation

The third and final step in the cost allocation process is to Allocate to the various customer classes the costs that have been Functionalized and Classified. The allocation process uses class characteristics that comport with the classification of the cost: Energy costs are allocated based on consumption by each class adjusted for losses to reflect energy at generation; Demand costs are allocated based on demand of each class also weighted for losses to reflect the load at generation; and Customer costs are allocated based on weighted customer count, class revenue, or estimates of the relative time and effort devoted to the customers in the class.

The allocation process also gives recognition to use of facilities by rate class such that, for example, customers who receive service at the Transmission level are excluded from the allocation of the cost of Subtransmission and Distribution facilities. Similarly, cost distinction between rate classes is drawn through the use of weighting factors. For example, a three phase non-demand meter is approximately fourteen times as costly as a single phase non-demand meter and this cost distinction is reflected in the customer weights used to allocate the capital cost of metering equipment. Manitoba Hydro has not made substantive changes to its allocators in PCOSS18 compared with direction flowing from Order 164/16, summarized below and detailed in Schedules 4.2 and 4.3 attached.

- Generation costs classified as Energy are allocated using un-weighted energy. Generation costs classified as Demand are allocated using the Winter Coincident Peak demand based on the top 50 domestic hourly peaks.
- Transmission costs classified as Energy are allocated using un-weighted energy. Transmission costs classified as Demand are allocated using the Winter Coincident Peak demand based on the top 50 domestic hourly peaks.
- Subtransmission costs are allocated using the Winter Coincident Peak demand based on the top 50 domestic hourly peaks.
- Distribution Plant costs classified as Demand are allocated using class Non-Coincident Peak. Distribution Plant costs classified as Customer related are allocated using weighted Customer count.
- Distribution Service costs are allocated using weighted Customer count.
- Net Export Revenue is allocated to domestic classes based on each class's share of Generation and Transmission costs, including the costs of directly assigned radial taps.

Updated Customer Weighting Factors

As part of its preparation of PCOSS18 and in response to direction flowing from Order 164/16 (Page 81), Manitoba Hydro has reviewed and updated its allocators for billings, collections, meter reading, inspections, customer service general costs and meter investment. The activities and costs have been disaggregated for purposes of cost allocation, transparency, and to the extent possible to ensure that only those customer classes provided the service were allocated the cost. Even with these changes, the COS methodology is largely consistent with past practice that allocates these costs on the basis of customer count, weighted customer numbers, revenue, or based on an estimate of time spent by personnel providing the service. Of the total O&M costs forecast in IFF16 of $518 million, approximately $87 million of these costs are functionalized to the Distribution Service function and sub-functionalized as follows:

- General Customer Service
- Other General Customer Service—Small Customers
- Industrial and Commercial Solutions
- Customer Billing
- Collections

- 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.

Billing, Collections, Meter Reading, Inspections

Billing related activities have been separated into five categories as shown in Schedule 4.4, the costs of which are largely allocated on a weighted customer count that gives recognition to those customer classes provided the services.

Collection-related costs include both the activities associated with customer accounts in arrears as well as Bad Debt expense. In Schedule 4.5, the cost of collection activity has been prorated between Residential and General Service groups on the basis of the number of accounts in arrears with the General Service classes' portion allocated to each of the GSS and GSM classes based on customer count. Similarly, bad debt expense is prorated between Residential and General Service based on the actual bad debt expense recognized for each group, with subsequent allocation based on customer count. The Area and Roadway Lighting and General Service Large classes are excluded from the allocation of all Collection-related costs which historically have no collection issues.

The allocation of meter reading costs is based on the relative frequency of scheduled meter readings by customer class excluding unmetered Area and Roadway Lighting (Schedule 4.6).

Inspection-related costs continue to be allocated on weighted customer count, which reflects the current forecast of residential inspection activity as well as commercial inspection activity. Commercial inspections have been prorated based on customer count to all general service customer classes.

The allocation of Meter Investment costs has also been updated in PCOSS18. Consistent with past practice, these costs have been functionalized as part of Distribution Plant. These costs have been allocated on the basis of weighted customer count derived based on the average replacement cost of the range of metering equipment used by customer class and voltage level (Schedule 4.7).

8.2.4 Direct Allocation

Consistent with past practice, assets and expenses incurred to provide service to only one customer class are directly allocated to that particular class. This includes costs associated with A&RL plant, radial taps for GSL >100, and energy costs for SEP customers.

Similarly, the costs associated with Diesel generation facilities are directly assigned to the Diesel class. While the costs of Diesel investment have been included in the study and drive the allocation of costs to the class, the results are not used for purposes of rate setting.

8.3 PCOSS18 KEY FEATURES AND DISCUSSION

As typical of past Cost of Service Studies, PCOSS18 has been prepared on the basis of the Corporation's financial forecast reflecting the 2017/18 rate setting period flowing from IFF16. While annualized costs (Revenue Requirement) underpins rates to be paid by customers, for purposes of Cost of Service, Manitoba Hydro also determines net plant investment or Rate Base for purposes of allocating certain Revenue Requirement costs such as Finance Expense and Contributions to Financial Reserves (Net Income). Rate Base is developed beginning with the ending balance of the year prior to the rate setting period, which in PCOSS18 is year ending March 31, 2016 and consists of gross investment (property plant & equipment, intangible assets and regulatory assets) plus forecast capital additions, less accumulated depreciation and customer contributions.

The Rate Base in PCOSS14 incorporated investment costs related to Wuskwatim and the Pointe du Bois spillway replacement, and is further increased in PCOSS18 by Riel 230 kV station, and the Adelaide distribution substation. Rate Base does not reflect the costs associated with Bipole III, Riel/Keewatinohk Convertor stations, or Keeyask as this infrastructure is not yet in-service.

A total revenue requirement of $1,910 million has been allocated to the various customer classes in PCOSS18. **Figure 8.5** and the discussion that follows reconcile the Revenue Requirement flowing from IFF16 to PCOSS18. The Revenue Requirement underpinning the Corporation's last Cost of Service Study, PCOSS14, is also provided for comparative purposes:

Figure 8.5 Reconciliation of Revenue Requirement

	IFF12 2013/14 Test Year $ (Millions)	IFF16 2017/18 Test Year $ (Millions)
Operating and Administrative	471	518
Finance Expense	444	574
Finance Income	N/A	(16)
Depreciation and Amortization	430	396
Water Rentals and Assessments	116	124
Fuel and Power Purchased	166	135
Capital and Other Taxes	96	132
Other Expenses	N/A	115
Corporate Allocation	9	8
Net Movement in Regulatory Deferral	N/A	(68)
Net Income	36	102
Total Cost of Service (Revenue Requirement)	**1,768**	**2,022**
Less Additional GCR (net of Bipole III Reserve Amount)	24	81
Less Other Revenue	15	30
Add Uniform Rates Adjustment	24	N/A
Total Revenue Requirement included in PCOSS	**1,753**	**1,910**

As discussed below and shown in Figure 8.5, a number of adjustments are made to Revenue Requirement for purposes of Cost of Service. Further, several accounting changes that impact the Corporation's Financial Forecast have transpired since the preparation of Manitoba Hydro's last Cost of Service Study and also impact PCOSS18.

8.3.1 Revenue

Figure 8.6 reconciles the differences between the overall revenue forecast in IFF16 to that reflected in PCOSS18. For comparative purposes, revenue as reflected in IFF12 (and PCOSS14) is also provided.

Figure 8.6 Reconciliation of Revenue

	IFF12 2013/14 Test Year $ (Millions)	IFF16 2017/18 Test Year $ (Millions)
General Consumers Revenue at approved rates	1,361	1,569
Additional GCR	48	88
Bipole III Reserve Account	N/A	(119)
Extraprovincial	344	454
Other	15	30
Total Revenue	**1,768**	**2,022**
Less Additional GCR (net of Bipole III Reserve)	24	81
Less Other Revenue	15	30
Add Uniform Rates Adjustment	24	N/A
Total Revenue included in PCOSS	**1,753**	**1,910**

General Consumers Revenue

General Consumers Revenue in IFF16 reflects revenue based on August 1, 2016 rates approved in Order 59/16.

Additional General Consumer Revenue reflects the revenue associated with the forecasted rate increase being sought through this Application. For purposes of Cost of Service, Manitoba Hydro excludes the additional General Consumer Revenue of approximately $88 million requested in its 2017/18 rate increase. This is done such that the results of the Cost of Service Study may be used as guidance in the determination of rate differentiation, if any, by class. Schedule 6.1 details class revenue and the allocation of adjustments to arrive at class/subclass revenue reflected in PCOSS18.

Additionally, for purposes of Cost of Service, the General Consumer Revenue includes revenue associated with Late Payment Charges. Late Payment revenue is allocated to the Residential Class based on a three year average of actual late payment revenue. The result is that 81% of Late Payment revenue is allocated to the Residential Class. The residual 19% of Late Payment revenue is allocated to the remaining classes on the basis of each class's forecast revenue, excluding GSL and the Street Lighting Class given there is typically no collection issues associated with these classes.

Bipole III Reserve Account

Since the preparation of IFF12 a Bipole III deferral account was established as directed in past Orders of the PUB. For IFF purposes, and thus for Cost of Service purposes, Manitoba Hydro has deferred recognition of these revenues until Bipole III is in service when the deferral will be used to offset the cost associated with the investment. Similarly, the incremental $6 million of revenue that is forecast to accumulate in the Bipole Reserve associated with the Additional General Consumer Revenue is also excluded from PCOSS18.

Export Revenue

The gross Extraprovincial Revenue from IFF16 is included in PCOSS18 and acts to reduce the revenue requirement borne by domestic customers. As shown in Figure 8.8, Extraprovincial Revenue is reduced by the costs of the Affordable Energy Fund, variable hydraulic operating & maintenance costs and a pro-rata share of water rentals based on export related share of total hydraulic generation. This determination of Net Export Revenue is consistent with direction flowing from Order 164/16, and significantly different than the past derivation that relied on an allocation process through the use of an Export Class. Net Export Revenue is credited to domestic classes based on each class's share of total Generation and Transmission costs shown in the Allocation Program (page 56).

Figure 8.7 Calculation of Export Share of Hydraulic Generation

	Export Share
Total Exports (GWh incl Losses)	10,218
Divided by: Total Hydraulic Generation (GWh)	34,270
Export Share of Hydraulic Generation	**29.8%**

Figure 8.8 Calculation of Net Export Revenue

	PCOSS18 $ (Millions)
Export Revenue	455.1
Less: Water Rentals (29.8% of $114.7M)	34.2
Less: Variable O&M ($340/GWh)	3.5
Less: Affordable Energy Fund	0.5
Net Export Revenue	**417.0**

As discussed in Tab 7 of the Application, IFF16 incorporates average revenues and generation costs from a multi-flow simulation of 104 historic system water flows rather than median water flows previously used in the second test year of the Financial Forecast and past Cost of Service Studies. This results in a decrease of approximately $5 million in Net Export Revenue for purposes of Cost of Service and a RCC impact not greater than approximately +/- 0.1%.

Other Revenue

Other Revenue of $30 million is forecast to be generated related to activities and services associated with assets or investment in assets rather than attributable to a particular customer class. This includes rental revenue, revenue associated with permit inspection fees and provision of services on customer owned plant, as well as contributions.

As a result of IFRS, amortization expense associated with non refundable contributions has been treated as deferred revenue and reported as Other Revenue in the IFF. Previously, the amortization of non-refundable contributions was an offset to depreciation expense. For Cost of Service purposes, Manitoba Hydro has re-classed the contribution amortization of $11 million included in Other Revenue in order to credit contributions against depreciation of the related asset. Contributions represent the incremental portion of investment in assets funded directly by customers. For Cost of Service purposes, Manitoba Hydro continues to treat contributions as a credit against the investment (a contra asset) that serves to reduce related revenue requirement expenses such as depreciation expense and finance expense. Treating the funds as revenue, as done for accounting purposes, ignores the nature of these contributions, a pivotal consideration in cost allocation.

The remaining $19 million of Other Revenue is related to rental revenue from Joint Use, revenue for use/rental of Manitoba Hydro property, Inspection Fees, and other miscellaneous revenue. Consistent with past practice in the Cost of Service Study, revenues associated with operating activities are identified and applied against their related operating expenses to the extent possible. For example, Joint Use revenue is applied against operating costs associated with Distribution Poles and Wires; Inspection Fee revenue is applied against inspection costs functionalized as Distribution Customer Services. The remaining revenue includes revenue generated through work on customer owned plant, which for purposes of Cost of Service, has been netted against the related expenses that appear in Other Expenses in the IFF. The residual net revenue has been applied against overall Operating expenses and functionalized broadly in proportion to labour costs.

8.3.2 Revenue Requirement Cost Components

In terms of the revenue requirement cost components, Manitoba Hydro has not made substantial changes to its Cost of Service Methodology since the PUB's public review and issuance of Order 164/16. The changes which have been made are consistent with direction flowing from that Order and reflect the update of several allocators that, in most cases, do not measurably impact cost responsibility by class. These refinements were discussed previously.

A number of events that impact costs have occurred since the preparation of the last Cost of Service Study, PCOSS14, reflecting the 2013/14 Fiscal Year. This includes changes flowing from the Corporation's adoption of IFRS for financial reporting purposes in 2015 and corporate restructuring. The costing changes related to IFRS are largely timing issues shifting costs between the balance sheet and income statement which impact overall revenue requirement. Since Cost of Service is more greatly influenced by asset cost changes (generation vs. transmission for example), Cost of Service tends to be less sensitive to these kinds of accounting changes. Manitoba Hydro does not believe that accounting-related IFRS changes have measurably affected revenue requirement by class (that is, cost to serve). However, while the intent of the allocation has not changed, modifications in Cost of Service were required to adapt to data input changes and some impacts to class cost responsibility will result. Accelerated secondary impacts in Cost of Service may also occur from the costs shifting from Rate Base to Revenue Requirement. A reduction in Rate Base will, all else equal, drive a commensurate reduction in the allocation of carrying costs in Cost of Service including for example, finance expense and net income that can impact some classes more greatly than others.

The impact of cost changes associated with corporate restructuring is not likely to result in measurable impacts to Cost of Service which are largely a function of changes in costs allocated to each class relative to other classes. However, given the details of the changes are not complete, definitive conclusions are not possible at this time.

Operating and Administrative

Operating and administrative (O&A) expenses are comprised primarily of labour and benefits, materials, contracted services and overhead costs associated with operating and maintaining all facilities of the corporation and providing services to customers. Consistent with past practice, the initial functionalization of O&A expenses of $518 million is provided through Manitoba Hydro's financial reporting system (SAP), via settlement cost centers as part of the detailed O&A budgeting process. As discussed in Tab 6, detailed O&A budgets will be prepared in support of the new corporate structure and thus are currently not complete. Manitoba Hydro has used the best available detailed budget data for purposes of PCOSS18 which flows from IFF15 reflecting 2016/17.

Additionally, as discussed in Tab 6 of the Application, significant cost reductions are anticipated flowing from corporate restructuring efforts. The cost associated with this restructuring effort of $50 million is reflected in Other Expenses in IFF16, and has been broadly allocated across all functions in proportion with total functionalized labour costs given that the detailed O&A impacts are not known at this time.

From a Cost of Service perspective, the basis of comparison is to the last Study prepared, PCOSS14. As identified in **Figure 8.5** and discussed in past General Rate Applications, the increase in O&A is largely attributable to accounting changes related to overhead no longer eligible for capitalization. There are two impacts to Cost of Service that result. First, while the intent of the COS methodology of overhead costs previously capitalized, now expensed, has not changed and continue to be allocated on the basis of labour, the labour allocators are not the same. Overhead previously capitalized would have been capitalized in proportion to direct labour charged to a capital project under construction. These overhead costs are now allocated based on operating-related labour costs. Secondly, as discussed above, the shifting of costs from Rate Base to Revenue Requirement can result in some disproportionate impacts by class. For Cost of Service purposes, this also applies to the $20 million of annual overhead ineligible for capitalization under IFRS deferred for rate-setting purposes notwithstanding that the timing impacts on Revenue Requirement have been eliminated through the Net Movement in Regulatory Deferral account.

Finance Expense and Income

For accounting purposes, Finance Income has now been presented separately from Finance Expense. There is no impact of this change for Cost of Service purposes. Consistent with past practice, Net Finance Expense has been allocated based on average Rate Base, that is, the average of net plant in service for fiscal years 2016/17 and 2017 /18 (Schedule 2.1).

Depreciation and Amortization

Since the preparation of PCOSS14 (IFF12), a number of changes have impacted the magnitude of the annualized expenses. These include a depreciation study which resulted in increases in service life of certain assets, a depreciation methodology change from Average Service Life (ASL) to Equal Life Group (ELG) discussed in Tab 6, and new asset additions.

IFF16 includes $396 million of Depreciation and Amortization expense which reflects the ELG depreciation methodology, functionalized through the Corporation's accounting system for purposes of Cost of Service. The movement from ASL to ELG has resulted in the shifting of cost between the balance sheet, income statement and also between Revenue Requirement cost components. Functional detail (referred to as asset categories in Tab 6) exists for the provision of the difference between ELG and ASL that flows through the Net Movement account. As such, the significant movement in these costs for accounting purposes has little effect on Cost of Service.

Additionally, detail continues to be available such that changes in capitalization policy of metering-related costs (meter sampling, exchange, and testing) can continue to functionalized and sub-functionalized consistent with past practice in COS.

The change in service lives since PCOSS14 has tended to decrease Subtransmission/Distribution-related depreciation costs, which will benefit customer classes served from the distribution system. However, these reductions have been offset by increases in Distribution investment since PCOSS14.

Water Rentals, Fuel and Power Purchased and Capital and Other Taxes

Water rentals, Fuel and Power Purchases continue to be functionalized as Generation in the PCOSS, as shown in Schedule 3.1.

Capital Tax has been functionalized on the basis of a single year end Rate Base as at March 31, 2018, consistent with assessment practice and as reflected in Schedules 2.3 and 2.4.

Payroll and Property Taxes included in Other Taxes are functionalized distinctively in Cost of Service. Payroll Taxes, as well as communication and building related Property Taxes are functionalized on the basis of labour costs. The remaining Property Taxes are assessed based on electric plant, and are functionalized in the PCOSS consistent with that assessment.

Other Expenses

Other Expenses of $115 million include $62 million of expenditures related to Power Smart (DSM), site restoration, and regulatory costs that are initially recorded in Other Expenses and then removed through the Net Movement accounts such that these costs can continue to be deferred. There is no impact in Cost of Service. The related amortization expense and data availability allows these costs to be treated in an identical manner compared to past practice. Power Smart costs that continue to be capitalized have been incorporated in Rate Base derived for Cost of Service purposes, functionalized to Generation consistent with Order 164/16 and used to drive the allocation of costs such as Finance Expense and Net Income. The related amortization expense also continues to be functionalized as Generation.

The COS treatment of the remaining Other Expenses include $50M of restructuring costs and a $2M provision for work on customer owned plant were discussed in Sections 8.3.2 and 8.3.1 respectively.

Corporate Allocation

Manitoba Hydro continues to allocate the interest related portion of costs on the basis of average Net Rate Base, and functionalize the amortization portion based on labour costs.

Net Movement in Regulatory Deferrals

The net movement in the regulatory deferral account represents the timing differences between the recognition of an expense for regulatory purposes and the recognition of the expense for financial reporting purposes. The $68 million balance of the regulatory deferrals represents the deferral of current year expenditures related to DSM, site restoration, regulatory costs, overhead and depreciation method differences, net of related amortization expense. For purposes of Cost of Service, these costs have been segregated and their impact discussed above.

Net Income

Net Income is a derivative of progress toward financial targets related to the Corporation's net investment, and a cost recoverable from all customers. In IFF16, Contributions to Reserves of $102 million are forecast. Consistent with past practice in Cost of Service, this cost has been allocated to all customer classes proportional to each class's allocated net plant in service (average Rate Base) provided in Schedule 2.1.

8.3.3 Energy, Demand and Customer Forecast

The third and final step in the cost allocation process is to allocate to the various customer classes functionally classified costs. The classification of costs into energy-related, demand-related and customer-related provides the basis by which costs are allocated to the customer classes. The Cost of Service Study reflects the Corporation's forecast of energy and customer numbers flowing from the updated 2016 System Load Forecast consistent with that reflected in IFF16. Energy savings flowing from the 2016 Power Smart Plan are applied to and offset forecasted consumption. Forecasted energy by class is obtained through the Proof of Revenue calculations as reflected in Tab 9 of the Application.

The Cost of Service Study uses the historical relationships between each class's energy consumption and their recorded demand, which is then applied to forecast energy to derive demand allocators for the test year. The load factors that quantify these relationships are provided through Load Research. The cost of service uses the average load factors from the eight most recent Load Research studies from 2007/08 to 2014/15.

8.4 PCOSS18 RESULTS

PCOSS18 as described above reflects a methodology consistent with that flowing from Order 164/16. Manitoba Hydro has revised its treatment of several allocators consistent with direction flowing from that Order, and those methodology changes are reflected in PCOSS18.

The figures below provide the results of PCOSS18 of total cost allocated by class, as well as the results of Rate Base by Function.

Figure 8.9 Comparison of Total Cost by Class

Customer Class	PCOSS14-Amended ($000)	PCOSS14 164/16 ($000)	PCOSS18 ($000)
Residential	627	713	811
General Service -Small Non Demand	132	143	152
General Service -Small Demand	138	157	185
General Service -Medium	200	227	253
General Service -Large 0 - 30kV	100	110	120
General Service -Large 30-100kV	62	68	87
General Service -Large >100kV	205	228	231
SEP	1	1	1
Area & Roadway Lighting	22	23	23
Diesel	10	10	9
Export	256	49	38
Total System	**1,753**	**1,729**	**1,910**

Figure 8.10 Comparison of Functionalized Rate Base Investment

Net Rate Base ($ millions) by Function						
	Gen	**Trans**	**Subtrans**	**Dist Plant**	**Dist Services**	**A&RL**
PCOSS14 164/16	6,769	1,108	428	1,943	112	71
PCOSS18	7,424	1,701	581	2,593	127	95

Figure 8.11 Comparison of Functionalized Rate Base Shares

Functionalized Rate Base (%)						
	Gen	**Trans**	**Subtrans**	**Dist Plant**	**Dist Services**	**A&RL**
PCOSS14 164/16	64.9%	10.6%	4.1%	18.6%	1.1%	0.7%
PCOSS18	59.3%	13.6%	4.6%	20.7%	1.0%	0.8%

Schedule 1.1 attached provides the RCC's flowing from PCOSS18. The ratios compare revenues of each class at current August 1, 2016 rates to its allocated costs. The RCC ratio provides the relative performance of each rate class over a base of 100%. The RCC's are also summarized in **Figure 8.12** and include results flowing from PCOSS14-Order 164/16 as well as PCOSS14-Amended to facilitate comparison and review.

The new methodology arising out of Order 164/16 puts RCC results, as well as allocated cost by class and cost components, at considerable variance from those derived using the previous methodology used in PCOSS14-Amended as can be seen in the tables below.

Figure 8.12 Comparison of Class RCC Results

Customer Class	PCOSS14-Amended RCC	PCOSS14 164/16 RCC	PCOSS18 RCC
Residential	99.9%	95.5%	94.8%
General Service - Small Non Demand	108.0%	108.5%	112.5%
General Service - Small Demand	104.5%	103.4%	101.0%
General Service - Medium	99.3%	100.3%	98.3%
General Service - Large 0 - 30kV	91.1%	96.1%	99.1%
General Service - Large 30-100kV	99.8%	108.0%	109.3%
General Service - Large >100kV	98.5%	107.1%	108.6%
Area & Roadway Lighting	100.3%	99.5%	100.3%

Figure 8.13 provides the unit costs flowing from PCOSS18 relative to the unit costs flowing from PCOSS14 and Manitoba Hydro's rates.

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.

8.5 RATE CHANGES BY CLASS

A Cost of Service study is considered to be the primary vehicle for evaluating the appropriateness of the overall cost responsibility and price level by customer class.

The main purpose of the study is to apportion the utility's costs which are then compared to expected revenue by class. The resultant comparison is known as a Revenue to Cost Coverage ratio ("RCC"). A customer class with revenues equal to apportioned costs would have an RCC of one ("unity"). It is generally accepted in utility ratemaking that a range of revenue to cost ratios are established, for Manitoba Hydro, its targeted range of RCC's or Zone of Reasonableness ("ZOR") is 95% to 105%, as directed by the PUB in Order 51/96.

The acceptance of a Zone of Reasonableness, rather than strict adherence to the results of a Cost of Service Study is suggestive of two things. First, the results of a Cost of Service Study provides a measure of relative rather than absolute costs; in other words, the accuracy of apportioned cost is within the range established. A range of values around unity is consistent with adding statistical significance to a statistical analysis. Thus, RCC ratios within the range are deemed to represent full cost recovery. This means that Cost of Service is useful as a first approximation of reasonable rates by class as a Cost of Service study, regardless of the methodology underpinning it, cannot identify for sure the cost of providing service by class. This occurs because the nature of the costs incurred by a utility reflect infrastructure that is commonly used by all or nearly all customers it serves. For Manitoba Hydro this also occurs because of the dominance of hydraulic investment that is significantly fixed and because of the magnitude of export revenue.

Secondly COS and its resultant RCC ratios is a tool that may (or may not) be used when evaluating and setting rates for various customer classes. The translation of cost to serve to pricing should reasonably balance a utility's ratemaking objectives. This means that rate equity is not achieved by using the results of a cost of service study to set rates purely in a mechanistic manner. Hence, a COS study is more a guide than a prescription in setting rates. Apportioned costs are rarely offered as final measures of fair and equitable rates and rate relationships in most jurisdictions.

In this jurisdiction, the PUB has broad discretion in the finding of just and reasonable rates for Manitoba Hydro. While a COSS is a very useful tool in assessing the fairness of rates and is the primary tool used by Manitoba Hydro to assess the allocation of costs between customer classes, its use is not mandated by legislation nor are costs the only measure by which to test the reasonableness of rates. In addition to considering the cost of service (including an appropriate net income for the maintenance of financial reserves), the PUB may consider other compelling policy considerations and other factors that the PUB may determine to be relevant. Therefore, apportioned costs by class are not the only factor to be considered, and a zone of reasonableness provides additional latitude in which to address non-cost related rate setting considerations.

A Zone of Reasonableness should not only reflect the variability in RCC outcomes that occurs with COS methodology uncertainty, but the degree to which other factors should influence rates. Such factors commonly considered include fairness and equity, economic efficiency, and historical precedence.

Order 164/16 took a disciplined view giving utmost regard to cost causation in the COS Methodology prescribed. Manitoba Hydro's previous Cost of Service methodologies gave weight to other ratemaking objectives including fairness and equity and efficiency in addition to cost causation. Order 164/16 recognized that ratemaking objectives beyond cost causation are appropriately considered in the ultimate determination of rates. Order 164/16 offered that fairness and other policy matters previously considered in the context of COS Methodology "are more appropriately considered in the establishment of rates"[3]. As a public crown-owned utility, Manitoba Hydro agrees that rate setting ultimately has to deal with issues beyond cost causation and in the absence of being handled through cost of service methodology, may alternatively be handled through allowing more variation in Revenue to Cost Ratios. As identified in Order 164/16 these policy and fairness matters include Marginal Cost consideration (page 53), the sharing of Export Revenue (page 32), and Uniform Rates (page 41).

[3] Order 164/16, page 6

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%

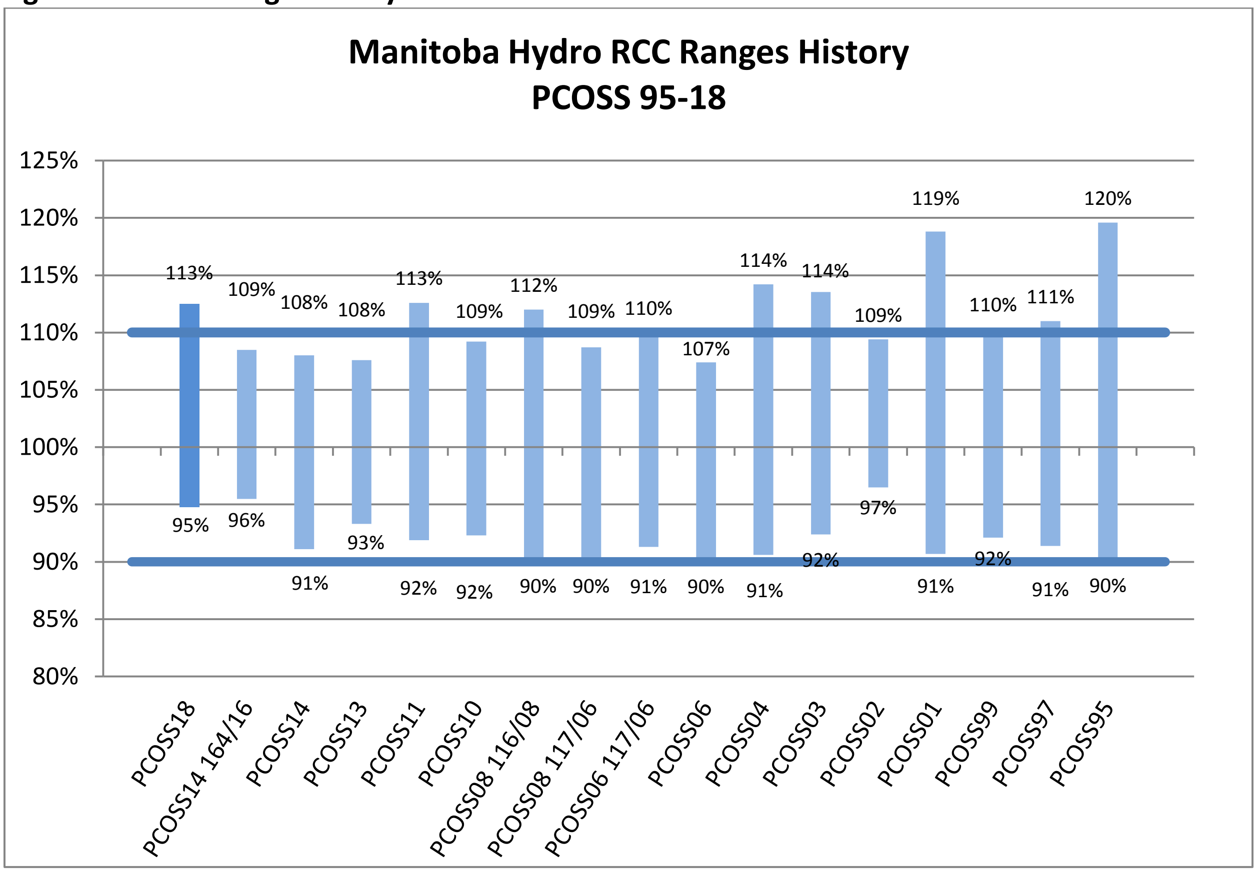
[4] 7.77 cents/KWh is the levelized marginal value used in the 2016 DSM Plan
[5] Exhibit 68, 2008 GRA

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.