Manitoba Hydro

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July 29, 2016

Mr. D. Christle
Secretary and Executive Director
Public Utilities Board
400-330 Portage Avenue
Winnipeg, Manitoba R3C 0C4

Dear Mr. Christle:

RE: MANITOBA HYDRO'S 2015 COST OF SERVICE METHODOLOGY REVIEW – REBUTTAL EVIDENCE

Please find attached Manitoba Hydro's Rebuttal Evidence with respect to the evidence of:

- Patrick Bowman, InterGroup Consultants Ltd. on behalf of the Manitoba Industrial Power Users Group ("MIPUG");
- William Harper, Econalysis Consulting Services on behalf of the Consumers' Association of Canada (Manitoba Branch) and Winnipeg Harvest ("COALITION");
- Paul Chernick, Resource Insight, Inc. on behalf of the Green Action Centre ("GAC");
- John Todd, Elenchus on behalf of the City of Winnipeg; and
- A.J. Goulding, Jerome Leslie and Ian Chow, London Economics International LLC on behalf of GSS/GSM ("LEI").

Should you have any questions with respect to the enclosed, please contact the writer at 204-360-3633 or Janelle Hammond at 204-360-4161.

Yours truly,

MANITOBA HYDRO LAW DIVISION
Per:

ODETTE FERNANDES
Legal Counsel

Att.

MANITOBA PUBLIC UTILITIES BOARD

IN THE MATTER OF *The Crown Corporation Public Review and Accountability Act*

AND IN THE MATTER OF Manitoba Hydro's
Cost of Service Methodology Review

REBUTTAL EVIDENCE OF MANITOBA HYDRO WITH RESPECT TO THE WRITTEN EVIDENCE AND WORKSHOP OF:

PATRICK BOWMAN, INTERGROUP CONSULTANTS LTD. on behalf of Manitoba Industrial Power Users Group ("MIPUG");

WILLIAM HARPER, ECONALYSIS CONSULTING SERVICES on behalf of Consumers' Association of Canada (Manitoba Branch)/Winnipeg Harvest ("COALITION");

PAUL CHERNICK, RESOURCE INSIGHT, INC. on behalf of Green Action Centre ("GAC");

JOHN TODD, ELENCHUS on behalf of the City of Winnipeg; and

A.J GOULDING, JEROME LESLIE, and IAN CHOW, LONDON ECONOMICS INTERNATIONAL LLC ("LEI") on behalf of General Service Small (GSS) and General Service Medium (GSM)

July 29, 2016

Manitoba Hydro

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INTRODUCTION

Manitoba Hydro's Rebuttal Evidence addresses the written evidence filed on behalf of the following parties with respect to Manitoba Hydro's 2015 Cost of Service Methodology Review:

- Mr. Patrick Bowman on behalf of the Manitoba Industrial Power Users Group ("MIPUG");
- Mr. William Harper on behalf of the Consumers Association of Canada/Winnipeg Harvest ("COALITION");
- Mr. Paul Chernick on behalf of the Green Action Centre ("GAC").
- Mr. John Todd on behalf of the City of Winnipeg; and
- Mr. A.J. Goulding, Mr. Jerome Leslie and Mr. Ian Chow, London Economics ("LEI") on behalf of General Service Small (GSS) and General Service Medium (GSM)

As per Order 84/16, Manitoba Hydro has divided its rebuttal evidence between the key issues subject of the oral hearing in September in Section 1, and those issues to be addressed through written submission in August in Section 2.

SECTION 1: KEY ISSUES SUBJECT TO ORAL EXAMINATION

1 EXPORT CLASS AND ALLOCATION OF NER

1.1 Manitoba Hydro's Treatment of Export Revenue in Cost of Service Provides a Reasonable Basis to Determine Appropriate Domestic Cost Responsibility by Moderating the Reduction of Generation and Transmission Embedded Costs with Revenue Derived from Export Markets that can Potentially be Disproportionately Greater for some Customer Classes than Others

In its Cost of Service ("COS") submission, Manitoba Hydro continues to include an Export Class, sub-divided into two subclasses with differing cost treatment: Dependable Sales and Opportunity Sales. This is the approach Manitoba Hydro has continued to propose since 2006, at the direction of the PUB at that time in Order 7/03 (page 98) and endorsed by Christensen Associates in their reports in 2012 and 2015. Within the COS, the purpose of the

Export Class is neither to assess the profitability of export contracts or the reasonableness of the prices contained in those contracts which are determined in the competitive interconnected markets. A COS study is not the appropriate tool for such evaluations. The purpose of the Export Class is to determine a reasonable share of Generation and Transmission cost to exclude from the cost responsibility borne by the domestic rate classes. Any surplus revenue, over and above that cost would be considered unrelated to the cost of serving domestic customer classes and therefore available for distribution on a basis other than use of those particular functions by the domestic classes.

1.1.1 Distinction between Dependable and Opportunity Sales

Manitoba Hydro proposes that Dependable Sales be allocated a full embedded cost share of Generation and Transmission cost, comparable to domestic classes and Opportunity Sales be allocated variable cost only. Supporting reasons for this differential treatment are provided in Manitoba Hydro’s response to PUB/MH I-2(b). In that response, Manitoba Hydro accepts that a case can be made for allocating fixed Generation and Transmission cost to Dependable Export Sales, although conceptually, not as much as to domestic sales because service to Dependable Exports is not as firm as domestic service, is not supported by reserves as are domestic sales, and in the case of hybrid sales may be supported with capacity and dependable energy provided by the export customer. That response noted further that the vast majority of embedded cost is incurred for the purpose of ultimately meeting domestic load.

The realization of the long-term cost advantages of large scale hydro facilities can result in lumpy rate base additions. As a consequence, Manitoba Hydro has the capability to commit to Dependable Sales over interim years, until capacity additions are necessary for the service of domestic loads. Thus, it is appropriate for Manitoba Hydro to assign a full share of embedded cost to Dependable Sales, and only variable cost to Opportunity Sales. The division of exports into Dependable and Opportunity wholesale sales categories is based on the proportion of Dependable surplus energy within total surplus energy. For PCOSS14 the proportions are 50% Dependable and 50% Opportunity.

Mr. Bowman is the only intervenor who has taken a position significantly different from that of Manitoba Hydro. Messrs. Harper and Chernick support Manitoba Hydro's proposed approach. LEI is supportive of the distinction between Dependable and Opportunity subclasses but recommends in Undertaking #35 that full embedded costs should be attributed to 63.8% of exports. Manitoba Hydro contends that attributing full embedded costs to 50% of exports based on the portion of Dependable Exports over the entire flow record is appropriate.

1.1.2 Opportunity Export Sales Should Not be Expected to Contribute a Full Share of Fixed Costs

Mr. Bowman's position is essentially that Manitoba Hydro's choice among alternative generation plans is driven in part by consideration of Opportunity Sales. From his Pre-filed Testimony at page 35:2-4:*…exports (including opportunity exports) did in fact cause that new generation to be high capital cost hydraulic generation plant, as opposed to lower cost alternatives."*

Mr. Bowman's observation is partially correct, viewed in isolation; however, it is insufficient to reach the conclusion, as he does, that Opportunity Sales should bear a full share of embedded Generation and Transmission cost. It is only partially correct because explicit formal consideration of potential Opportunity Sales revenue in system planning only began sometime in the 1970's or later[1].

As such, the historical record does not support Mr. Bowman's categorical statement. It is apparent that all legacy hydro generating stations still in service, up to and including Long Spruce, produce Opportunity energy sales and revenue. Hence, a significant portion of Opportunity Sales is derived from plants whose commitment was made without explicit consideration of Opportunity Sales revenue.

Mr. Bowman's observation, even for that subset of plant to which it may apply, is not sufficient to reach his conclusion that all Opportunity Sales should be allocated a full share of

[1] See for example Commission of Inquiry into Manitoba Hydro: Final Report, December 1979, page 343 *"Until 1974, it was apparently Hydro's official policy that the system operators should always attempt to exploit fully short-term export and import opportunities but that the system planners should not incorporate any such opportunities unless reflected in firm contractual commitments"*

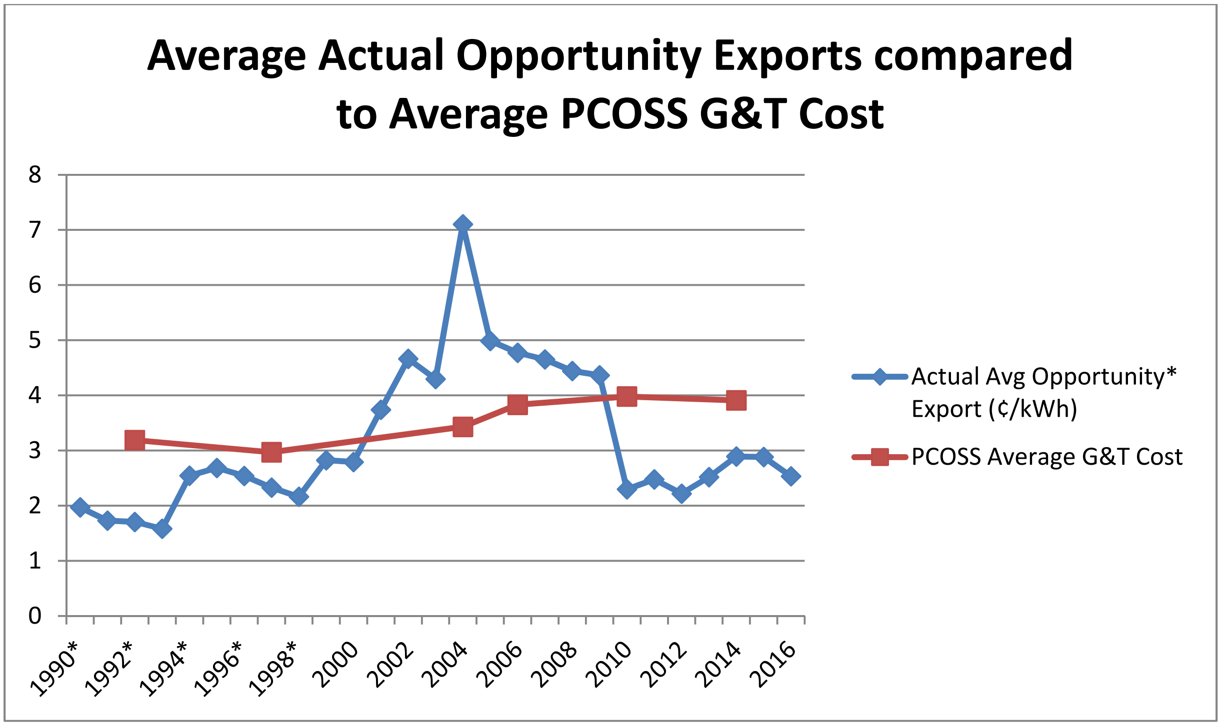
embedded Generation and Transmission cost. There is no evidence that planners at the time expected that such sales would be capable of fully recovering all embedded cost on an average unit basis. More likely, the expectation was that they would cover variable cost and make some irregular contribution toward fixed cost. In any event, experience over the past several decades is that such sales only recover embedded cost in exceptional years, such as during the robust market period in the early and middle years of the previous decade. More typically Opportunity Sales will recover between 50 and 80 percent of embedded Generation and Transmission cost as depicted in the table and chart below:

Table 1: Average Actual Opportunity Export Prices compared to Average PCOSS G&T Cost

Fiscal Year	Average Actual Opportunity* Export Price (¢/kWh)	Average G&T Cost PCOSS (¢/kWh)	Recovery of G&T Cost
1982	1.58	2.02	78%
1992	1.71	3.19	54%
1997	2.33	2.97	78%
2004	7.10	3.43	207%
2006	4.77	3.83	125%
2010	2.30	3.98	58%
2014	2.89	3.91	74%

***** 1982-1997 export prices do not distinguish between Dependable and Opportunity Exports, price shown is overall average export price. Average Opportunity prices fluctuate with water supply and other supply and demand factors

Figure 1: Average Actual Opportunity Exports compared to Average PCOSS G&T



* 1990-1999 export prices do not distinguish between Dependable and Opportunity Exports, price shown is overall average export price

In its response to PUB/MH I-2(b) Manitoba Hydro has noted:

> *"To the extent that Manitoba Hydro were to make investment and, as a result, incur embedded cost in order to secure opportunity sales, cost causation principles would require that those embedded costs be allocated to the opportunity class."*

Mr. Bowman observes that some recent generation plant commitments may have been made, in part, based on prospective Opportunity Sales (among other factors such as Dependable Sales, environmental attributes, provincial and local social and economic impacts etc.). However, a degree of potential cost consideration does not equate to a full share of embedded cost. An important distinction here is "causality" from "consideration": Domestic load is the reason/cause to which MH builds plant for the future; Opportunity Sales (and Dependable) are a "consideration" within the economics.

As discussed above, Manitoba Hydro's approach to costing exports does not purport to be precise but provides a reasonable approximation of the cost incurred to facilitate Dependable and Opportunity Export sales.

Manitoba Hydro's methodology computes the ratio of Opportunity to Dependable Export volume as approximately 50:50 based on simulation of the system operation using the entire long term hydraulic flow record of over 100 years, the supply mix, and load forecast for years 3 to 7 of the Integrated Financial Forecast. Manitoba Hydro notes that use of the entire historical flow record is a long established methodology utilized extensively at previous GRAs and the recent NFAT. Unfortunately, LEI's statistical approach to define this split remains too narrow to be relied upon, even after modifications made in Undertaking 35. The modified LEI analysis relies on a relatively brief historical data period from 2000 through 2015. Even though this period now includes the 2003/04 drought, overall it is a period of above average flows. The period does serve to highlight the significant drought which occurred in 2003/04, during which Opportunity Exports dropped to 735 GWh, only 7% of the record 10,303 GWh of Opportunity Export that occurred during the 2005/06 high water period[2]. This large swing in Opportunity Export volume highlights the uncertainty as to their availability. Hence Opportunity Sales, which are made subject to water availability and typically not backed by generation capacity, are a much lower grade product reflected in their price (Figure 1 above). In addition to limitations due to the small sample size used, the LEI analysis continues to be based on an erroneous underlying assumption that export volumes are normally distributed – which they are not. Furthermore, in its simple analysis of historical data, LEI ignores the effect of other system changes over that period that may not reflect the future – for example the addition of wind generation and load growth.

1.1.3 No Export Class

A "No Export Class" concept was raised during the course of the Workshops; by Mr. Bowman (Intervenor Workshop Transcript page 828) and by Daymark (Manitoba Hydro Workshop Transcript page 348). Additionally, while supporting an Export Class in his evidence (Pages 34-37 and 47-50), Mr. Bowman appears to have introduced a change in

[2] See Manitoba Hydro Undertaking No 5 for volumes.

perspective in response to Undertaking 33 (Page 4):

> "*Further consideration is needed on the potential for no export class and all exports simply credited back to the relevant functions that support exports. This would materially simplify the COS Study and reflect a principled linkage to the functions giving rise to the export revenue.*"

This approach might be appropriate in the circumstances where exports are a relatively small part of the utility's business or that the revenue from such sales, if they are significant, reasonably comports with the cost incurred. Where low prices for Opportunity Sales exist, and Net Export Revenue is constrained, the "No Export Class" option may be a reasonable cost of service approach. However, when there are significant export sales, with revenues well in excess of reasonably allocated cost, there is a risk of providing excessive subsidies to domestic classes. This is particularly true for those classes for which the vast majority or the entirety of cost is made up of Generation and Transmission. In either scenario the question remains of how to allocate export revenue, which in PCOSS14-Amended is $345 million or almost 20% of total revenue requirement. Allocating export revenue on the basis of each class' Generation and Transmission costs as suggested by Mr. Bowman will give rise to the same concerns that originally prompted the creation of an export class. Current expectations (2016/17 Supplemental Filing Attachment 16, page 2) are that unit export revenues will again increase requiring intervention in COS to moderate potential over-subsidization for some customer classes.

The following table provides RCC's based on PCOSS14-Amended assuming a "No Export Class" approach. In the last column, PCOSS14-Amended has also been prepared assuming export revenues at the PCOSS06 level of $550 million to illustrate how RCC's change by class as export revenue grows even though the underlying embedded cost is unchanged. This is the issue that prompted the creation of an Export Class.

Table 2: Comparison of PCOSS14 Methodology to No Export Class Methodology under Current and Higher Export Prices

Customer Class	PCOSS14-Amended	PCOSS14-Amended No Export Class	PCOSS14-Amended High Opportunity Prices	PCOSS14-Amended High Opportunity Prices No Export Class
Residential	99.9%	98.8%	100.1%	97.3%
General Service - Small Non Demand	108.0%	106.4%	107.7%	105.0%
General Service - Small Demand	104.5%	104.0%	103.8%	103.6%
General Service - Medium	99.3%	99.7%	99.2%	100.3%
General Service - Large 0 - 30kV	91.1%	92.8%	91.9%	94.8%
General Service - Large 30-100kV	99.8%	101.2%	99.8%	103.8%
General Service - Large >100kV	98.5%	100.7%	98.4%	104.2%
Area & Roadway Lighting	100.3%	99.8%	94.6%	93.4%

Alternatively, if a no Export Class alternative was used, a reasonable argument could be made that export revenue be allocated across all functions on total investment, consistent with the allocation of Net Income, given that export revenue is integral to the determination of Net Income (MH Submission, page 18). The RCC impacts by class of this scenario are provided in Table 3 below.

Table 3: PCOSS14-Amended with No Export Class and NER Allocated on Rate Base

Customer Class	RCC
Residential	101.6%
General Service - Small Non Demand	109.0%
General Service - Small Demand	104.8%
General Service - Medium	98.7%
General Service - Large 0 - 30kV	89.2%
General Service - Large 30-100kV	96.7%
General Service - Large >100kV	94.4%
Area & Roadway Lighting	110.8%

1.1.4 Excluding NER from COS or Directing it to a Reserve Fund Produce Results Nearly Identical with Manitoba Hydro's Methodology of NER but are Significantly More Complicated. There is No "Do Nothing" Alternative.

MIPUG's proposals to exclude Net Export Revenue from COS or direct it to a designated reserve fund produce results that are nearly identical to Manitoba Hydro's allocation of NER but are significantly more complicated. Mr. Bowman does not appear to support Manitoba Hydro's sharing of NER on the basis of each class' total allocated cost, although his evidence is unclear. Based on his pre-filed testimony and response to Undertaking 32, his preferred approach appears to be one of the following:

1. Indexing: Exclude NER from COS entirely and evaluate Customer Class RCCs relative to an overall RCC which incorporates domestic revenue less than domestic allocated cost if NER is positive; or
2. Direct NER into a specially designated reserve fund

Dealing first with the option to exclude NER from COS, Mr. Bowman states on page 5 of his Pre-Filed Testimony:

> *"The Net Export Revenue (NER) category represents revenues that are is (sic) not inherently linked to costs, but instead are a form of residual after the export class is allocated its fair share of system costs based on the export load profile and capital planning assumptions. As such there is a reasonable basis to not allocate the NER via the Cost of Service study."*

Manitoba Hydro does not disagree with either statement, but is concerned that the record does not clearly identify the consequence of not allocating NER within the Cost of Service study. A decision not to allocate NER within COS may appear appealing and be viewed as less controversial as it does not require explicit direction on how to distribute the export related benefits. However, there is no "do nothing" alternative for dealing with Net Export Revenue in Cost of Service and it is important to understand the effects of such an option so it is not determined to be the preferred approach for inappropriate reasons. As demonstrated below, the removal of NER, or Mr. Bowman's "Indexing" approach implicitly results in an allocation of NER on the basis of each class' revenue.

Excluding NER from COS results in total domestic costs which are not equal to domestic revenues. In other words, COS would no longer reflect Manitoba Hydro's approved Revenue Requirement. The result is that all RCC's will fall as Manitoba Hydro's costs are supported, in part, by all export revenue, including NER as determined in COS. Table 4 below provides the resulting PCOSS14-Amended RCCs excluding any allocation of NER as Mr. Bowman recommends. The table also provides the new RCCs scaled against the overall domestic RCC of 94.0% (ie Residential RCC of 93.8% restated against domestic RCC of 94.0% yields an indexed RCC of 99.8%).

Table 4: Indexed Class RCC with No Allocation of NER

Customer Class	Cost ($000)	Revenue ($000)	RCC	Indexed RCC
Residential	627,351	588,630	93.8%	99.8%
General Service - Small Non Demand	132,320	135,035	102.1%	108.5%
General Service - Small Demand	138,038	136,080	98.6%	104.8%
General Service - Medium	200,188	186,797	93.3%	99.2%
General Service - Large 0 - 30kV	99,833	84,956	85.1%	90.5%
General Service - Large 30-100kV	61,642	57,808	93.8%	99.7%
General Service - Large >100kV	204,686	189,258	92.5%	98.3%
Area & Roadway Lighting	21,964	21,630	98.5%	104.7%
Total Domestic*	1,496,937	1,407,631	94.0%	100.0%

*Includes SEP and Diesel class

In Table 5 below, NER has been allocated on the basis of domestic revenue, rather than excluded from the study. A comparison of Table 4 and Table 5 show that the resulting RCCs are identical.

Table 5: Class RCC with NER Allocated on Class Revenue

Customer Class	Cost ($000)	Revenue ($000)	NER on Revenue ($000)	Total Revenue ($000)	RCC
Residential	627,351	588,630	37,345	625,975	99.8%
General Service - Small Non Demand	132,320	135,035	8,567	143,602	108.5%
General Service - Small Demand	138,038	136,080	8,634	144,714	104.8%
General Service - Medium	200,188	186,797	11,851	198,648	99.2%
General Service - Large 0 - 30kV	99,833	84,956	5,390	90,346	90.5%
General Service - Large 30-100kV	61,642	57,808	3,668	61,475	99.7%
General Service - Large >100kV	204,686	189,258	12,007	201,265	98.3%
Area & Roadway Lighting	21,964	21,630	1,372	23,002	104.7%
Total Domestic*	1,496,937	1,407,631	89,307	1,496,938	100.0%

*Includes SEP and Diesel class

Therefore, a decision not to allocate NER in COS is identical to a decision to allocate NER based on class revenues.

Further, as demonstrated in Table 6 below, a class revenue allocation of NER (or the exclusion of NER in COS) results in an outcome not materially different for most classes than Manitoba Hydro's current approach to allocate NER on the basis of total allocated costs.

In fact, if all classes were at unity, the only difference between the current allocation on Total Allocated Costs and no allocation of NER after indexing would be due to directly assigned costs that did not receive a share of export revenues. Accepting Mr. Bowman's recommendation to remove Net Export Revenue from COS is also an implicit endorsement that a share of revenues should be provided to the directly assigned costs of dedicated end-use facilities as proposed by Mr. Todd (Pre filed Evidence, page 2) and London Economics (Pre filed Evidence, page 10). The 4.4% increase in Area and Roadway Lighting identified in Table 6 is almost entirely due to the implicit assignment of NER to dedicated assets.

Table 6: NER Allocated on Total Cost vs Class Revenue

Customer Class	PCOSS14-Amended RCC (NER on Total Allocated Cost)	RCC (NER on Revenue)	Difference
Residential	99.9%	99.8%	-0.1%
General Service - Small Non Demand	108.0%	108.5%	0.5%
General Service - Small Demand	104.5%	104.8%	0.3%
General Service - Medium	99.3%	99.2%	-0.1%
General Service - Large 0 - 30kV	91.1%	90.5%	-0.6%
General Service - Large 30-100kV	99.8%	99.7%	-0.1%
General Service - Large >100kV	98.5%	98.3%	-0.2%
Area & Roadway Lighting	100.3%	104.7%	4.4%
Total Domestic	100.0%	100.0%	0.0%

With respect to Mr. Bowman's second option, the directing of NER into a reserve fund, he states (MIPUG Undertaking 32, Page 1):

> "*Mr. Bowman does not advocate any creation of rainy days funds or the like. Mr. Bowman's evidence only deals with the matter of Cost of Service and how to treat NER in the Cost of Service calculations. Setting up any such fund, if it were to occur, is a concept for a future Revenue Requirement review*"

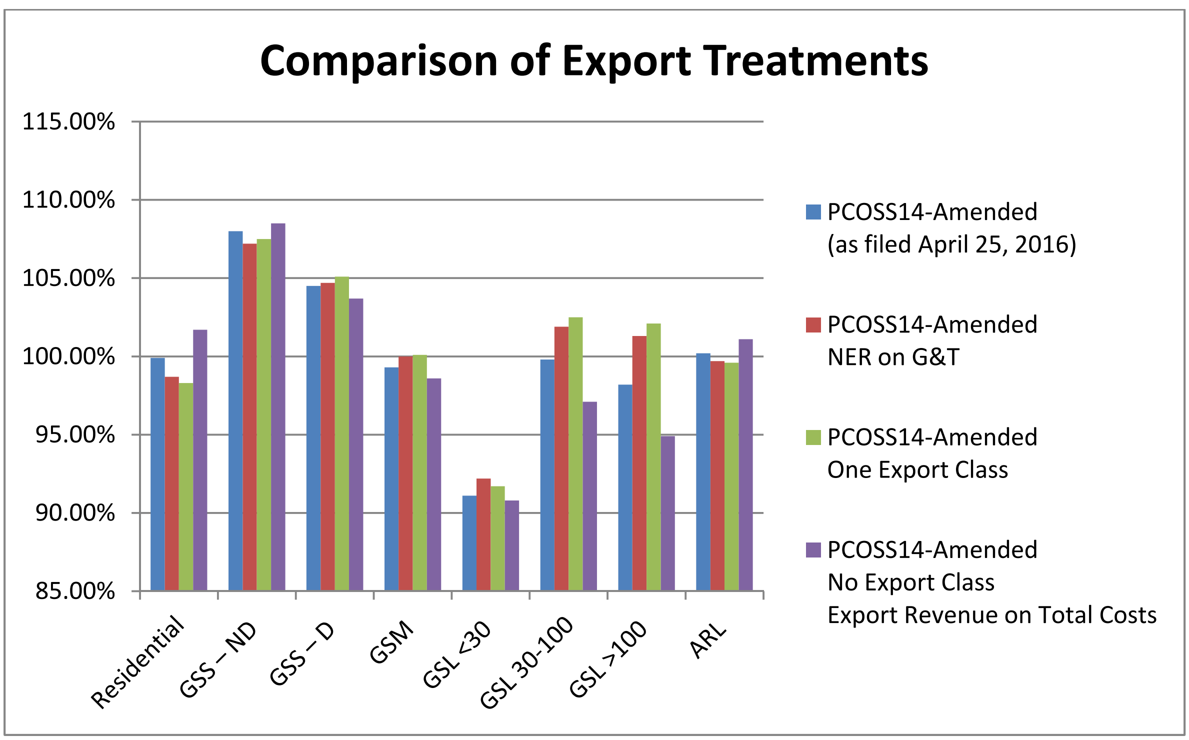
Mr. Bowman then goes on for numerous pages to discuss limited differential rate changes, higher rates, and the Bipole III Reserve Account all of which are inferences that a Reserve Fund can reasonably be used for the treatment of NER in COS at some point. A key distinction to be made is that items such as the BP III Reserve Account are inputs into the Revenue Requirement, while NER under the current export class approach is the final output of a detailed cost allocation. Using the output of the COS study to somehow modify the Revenue Requirement used as an input into that same study is circular, unnecessarily complex, and not practical.

Manitoba Hydro agrees with Mr. Bowman that a reserve fund, no matter how or why it is calculated is a Revenue Requirement matter. These matters are not within the scope of the current proceeding. In fact the PUB has already determined that Manitoba Hydro's financial targets and the adequacy of the financial reserves are matters that will be considered at the next GRA (Order 73/15, page 57). Moreover from a Cost of Service perspective whether a "fund" is sourced from NER, increased revenue or changes in Net Income the class RCC ratios are minimally affected as demonstrated in Tables 4 and 5.

1.1.5 Impacts

The net effect of using either one export class or no export class (allocating all export revenue to customers on the basis of each class' allocation of generation and transmission costs) is to shift cost responsibility away from the largest customers of Manitoba Hydro to the smallest users such as the Residential customers as shown in Figure 2 below. These recommendations do nothing to address the issue that first gave rise to the Export Class as directed by the PUB in Order 7/03 and which the Corporation agreed and implemented in 2006. The chart below isolates impact to each customer class of the alternatives to address export revenue in COS.

Figure 2: Comparison of Export Treatments



2 MANITOBA HYDRO'S USE OF WEIGHTED ENERGY IS AN APPROPRIATE METHOD OF CLASSIFYING AND ALLOCATING GENERATION, GENERATION-RELATED TRANSMISSION AND U.S INTERCONNECTIONS

Manitoba Hydro's use of Weighted Energy is an appropriate method of classifying and allocating the cost of Generation, Generation-related transmission and interconnections. The Evidence of Mr. Bowman on this matter is substantially contained on pages 19-23 of his Pre-filed Testimony. In summary, Mr. Bowman is supportive of the marginal cost weighted energy allocator but recommends that Generation and Generation-related Transmission costs be first classified into Demand-related and Energy-related components utilizing traditional embedded costs methods focused on internal Manitoba Hydro costs with only Energy-related costs being allocated on the basis of Weighted Energy (excluding the capacity adder). He then goes on to recommend that Demand-related costs be allocated on the basis of class contribution to coincident peak (CP) in the winter period, which is when the domestic customer load peaks.

Mr. Harper and Mr. Chernick support use of the marginal cost weighted energy approach for all Generation related cost but do not support the inclusion of the capacity adder or any other capacity related allocator because it is either pre-mature (Mr. Harper on page 64 of his Evidence) or unnecessary (Mr. Chernick on page 27 of his Evidence).

Previous to the filing of PCOSS06 and the 2006 Cost of Service Review Manitoba Hydro's classification and allocation of Generation and related cost was as follows (from PUB-MFR 4, page 12):

- Generation and Transmission cost were classified to Demand and Energy-related components using the System Load Factor method. All grid transmission was then considered to be Demand-related with the residual Demand-related costs applying to Generation. This resulted in a Generation classification ratio of 82% Energy and 18% Demand.
- Generation Energy was allocated on the basis of class contribution to Annual Energy at generation and Demand on the basis of the average of Summer and Winter Peaks,

with each of these being the average of the top 50 hours in each season. The inclusion of the summer peak reflected the incorporation of an Export class into the COSS and its contribution to a summer peak that is almost as high as the winter peak.

In PCOSS06 Manitoba Hydro proposed a conceptually substantial change to the process of Classification and Allocation of Generation and related costs. This change meant that, rather than using traditional classification and allocation factors such as System Load Factor, domestic Coincident Peak and Annual Energy, the allocation of embedded generation cost would be driven by the short run cost to supply domestic loads, measured in terms of the market value of power – essentially, an opportunity cost approach.

Manitoba Hydro adopted the use of marginal costs to classify and allocate generation costs to better reflect cost causation. Marginal costs capture the economic value of resources while, at the same time, reflects how Manitoba Hydro plans and operates its largely hydraulic system facilities, which are operated in order to take advantage of their relatively low variable costs. The incorporation of the market prices within COS integrates economic and financial cost concepts. That is, the market price of power constitutes Manitoba Hydro's opportunity cost associated with the revenue given up, or the cost incurred to import power. Further, marginal cost-based COS (Weighted Energy) allocates proportionately more generation-related costs to those customer classes who use comparatively high levels of energy when power is most highly valued. As a consequence, equity and efficiency goals are accounted for within the context of embedded cost of service. The marginal cost (Weighted Energy) methodology is relatively simple, straightforward, and lends itself to more granular application than a capacity/energy split.

The relative short run cost in each of four time periods was applied to weight energy usage by classes in the Cost of Service Study across four time periods (Summer Peak; Summer Off-Peak; Winter Peak; Winter Off-Peak). In effect, loads during high cost peak periods would be allocated a greater share of Generation and related cost. While this method actually reflected the real impact on Manitoba Hydro's bottom line, as a consequence to incremental increases or decreases in domestic usage, it does not track internal variable or fixed costs, as actually incurred by Manitoba Hydro, which do not change substantially over short-term variation in loads, during typical water years (median water year).

In the majority of hours during the year, the marginal cost weighting factor is driven by changes in fuel cost reflecting the generation mix, capital cost/fuel cost trade-off considerations and customer demands in neighbouring interconnected markets. At that time the MISO market was an energy-only market so a specific value for capacity distinct from the energy price and based on a short run marginal cost was not available. It can be debated the extent to which these varying time period costs reflect capacity scarcity rents versus fuel cost considerations in isolation. None the less, relative to the Annual Energy allocator previously used in the PCOSS, it is not a pure 100% Energy allocator. It does place greater weight and cost responsibility on peak period usage. In PCOSS14 for example, Winter Peak usage is given 3.66x more weight and cost responsibility than Summer Off-Peak usage.

The only times that the short term marginal energy costs actually represent internalized Manitoba costs are times when the interties are constrained (short run marginal cost is then the variable cost of generating additional energy on the Manitoba Hydro system) or, alternatively, when Manitoba Hydro must use its own thermal generation as its source of marginal supply. During 2015, for example, SEP energy was sourced from displaced exports during 96% of peak period hours, 94% of shoulder hours and 87% of off-peak hours.

Manitoba Hydro has utilized the marginal cost Weighted Energy approach to classify and allocate Generation and related costs since PCOSS06 with two modifications. Pursuant to a directive in Order 117/06, Manitoba Hydro expanded the number of time periods from four to 12 to recognize four seasons and peak, shoulder and off-peak periods within them.

The other modification is the addition of the capacity adder in PCOSS14-Amended. This was done in response to a recommendation from Christensen Associates and was intended to reflect their concern that the energy prices and their variation over the periods did not adequately incorporate the market value of capacity. Unfortunately however, the capacity market in MISO is relatively recent and the auction procedures may result in abrupt movement in capacity prices between unusually high and extremely low values (eg $0.10 per kW per month).

Recognizing that the value of capacity could be very volatile, ranging from near zero in the current situation to very high prices under tight market conditions, Manitoba Hydro adopted as its capacity adder the same stable value that it uses to compensate Curtailable Rate customers for their relinquishing of capacity during high load hours, currently at $3.17 per kW per month. In PCOSS14-Amended, this capacity adder was spread over all peak hours in the year, resulting in an added quantum of approximately $0.02 to the peak period marginal cost and raising the peak period weights by approximately 30%.

Mr. Bowman's Testimony does not take issue with Manitoba Hydro's approach to use marginal Weighted Energy cost differentiated by time period to allocate Energy-related cost of Generation (page 20:23-25). However, Manitoba Hydro understands his evidence to be that before such allocation is undertaken, a portion of Generation and related cost should be classified as strictly Demand-related and allocated on the basis of class contribution to Winter Peak demand (page 23:14-15).

In order to determine the appropriate portion of Generation and related cost to classify as Demand-related, Mr. Bowman offers up traditional embedded cost approaches as reasonable initial bases. The System Load Factor (SLF) method which was used by Manitoba Hydro prior to 2006 would yield a Demand-related component of 21% according to Mr. Bowman. The approximate ratio using the Equivalent Peaker (EP) method would be 23% (page 23: 4-11).

Mr. Bowman's Testimony does not comment on the rationale for treating the Capacity or Demand-related component in an entirely different way from the Energy component in assigning cost drivers. For the Energy component he is satisfied to have short run marginal cost, largely driven by market prices at the MISO interconnection, produce weightings and cost responsibility, which are significantly higher at peak periods. However, for capacity he does not appear to see value in using market price signals but wants to fall back on more traditional embedded cost procedures that have no apparent tie to marginal cost in either Manitoba or external markets.

Similarly, with respect to Allocation, Mr. Bowman wants to partially sever the link to interconnected market and rely on an allocator which is tied mostly to domestic demand. He would choose an allocator which substantially ignores the export demand at the summer peak.

Manitoba Hydro is not aware of other utilities which use the market price weighted allocators for Generation cost and also use traditional embedded cost methodology for an initial classification between Demand and Energy. The source cited in Mr. Bowman's evidence in footnote 27, page 23 is a jurisdictional comparison of cost of service methodologies at utilities deemed to be the best comparators for BC Hydro, which would also make them reasonable comparators for Manitoba Hydro. Of the 11 utilities included in the review, none used the Equivalent Peaker methodology to classify Generation and related cost between Demand and Energy. Four used the System Load factor method:

- Hydro Quebec Distribution used SLF to classify its purchase cost for heritage resource supply which still makes up the bulk of power supply for HQD.
- Newfoundland Power used SLF to classify hydro generation cost.
- Avista Washington used SLF to classify the cost of all hydro; thermal, purchased power, transmission and net wholesale income.
- Idaho Power used SLF to classify hydro, non-peaking thermal and purchases

None of the four utilities using SLF to classify Generation cost also used a weighted energy approach such as Manitoba Hydro's to subsequently allocate the Energy-related portion of Generation cost. All but Idaho power used annual un-weighted energy at generation for allocation. Idaho Power used a hybrid approach which averaged weighted and un-weighted energy.

It would, intuitively, not seem reasonable to mix the two approaches. Mr. Bowman's recommended approach which focuses on internal embedded cost which would, for the Energy portion be nearly entirely fixed, since only variable Energy-related costs would vary among time periods and a substantial portion of Energy related cost in Manitoba is fixed, not variable. Even the variable portion (water rentals, thermal fuel, variable O&M and purchased power) may not vary significantly between peak and off-peak periods in a median flow year. If it is reasonable to abandon the current approach of implicitly recognizing Demand in the Weighted Energy allocator in favor or a more traditional classification process, as recommended by Mr. Bowman, then it should be consistent and allocate Energy-related cost on the basis of Annual Energy at generation. Alternatively, one could also find consistency by using Manitoba Hydro's short run marginal cost weights with a capacity adder, as proposed by Manitoba Hydro in PCOSS14-Amended.

Mr. Chernick, on behalf of Green Action Centre, believes that any consideration of capacity in the allocation of Generation related cost is inappropriate. At 27:1-3 of his Evidence he states that there is no need to consider capacity: "*The purpose of the energy weighting is to apportion to time periods a group of costs that are driven by energy requirements. These costs are not driven by capacity requirements.*"

While it is true that Manitoba Hydro's generation mix is such that, as load grows, energy constraints are encountered before capacity constraints, Manitoba Hydro must consider both capacity and energy in the design of additional plant.

Elsewhere in his Evidence however, Mr. Chernick appears to be suggesting that, if the PUB wanted Manitoba Hydro to incorporate a capacity adder, it should incorporate the annual capacity prices from the MISO market and provides a table of such prices at the top of page 29 of his Evidence. Mr. Chernick's table illustrates a volatile range of capacity prices, from zero up to $43.80 per kW/yr. and this during a period that has generally been capacity long. On the other hand, Manitoba Hydro's proposed approach provides a stable option for reflecting capacity.

Mr. Harper does not appear to be opposed to the idea of including a capacity adder within the weighted energy allocation but rather that it needs to be given further consideration as to whether it is needed, what the value should be and into which seasons and hours it should be incorporated. His perspective is that, until such time as these issues are resolved it is premature to incorporate a capacity adder (page 64).

There may be scope for debate regarding the hours over which the capacity adder should be applied. However, the use of such an adder as well as the use of the internal marginal capacity costs absent reliability capacity auction prices – rests on solid ground and is a well recognized elsewhere and commonly used elsewhere for purposes of cost allocation.

3 BIPOLE III IS NEEDED TO MEET SUMMER ENERGY REQUIREMENTS

Mr. Bowman asserts that Bipole III is only required for the winter period both in his Pre Filed evidence (MIPUG page 30 and 31) as well as at Transcript page 119.

Mr. Bowman uses Manitoba Hydro's submissions at the CEC hearing as evidence of this assertion. Manitoba Hydro's focus during the review of Bipole III at the CEC hearing was ensuring that parties understood the seriousness and reality of consequences associated with the loss of Bipoles I and II to Manitoba Hydro's customers during the winter months. Although less emphasis was placed on the importance of Bipole III during the summer months.

Bipole III is required in summer and in the winter to cover for loss of Bipoles I and II. The line and converter stations are driven by reliability need for Manitoba's capacity and energy requirements in the summer and winter. If Bipole I and II are down for an extended period, curtailment of Manitoba load is likely in both seasons.

Figure 3 is a chart of hourly Manitoba demand for Summer 2015. Clearly Manitoba demand exceeds the available generation in Manitoba following loss of Bipoles I and II. Figure 4 includes this same information sorted into a distribution. As shown in Figure 4, demand in Manitoba would have exceeded supply in Manitoba following loss of Bipoles I and II approximately 60% of the time. Curtailments of up to almost 1,000 MWs could have occurred. Note that this analysis is specific to the summer season, and uses a different level of imports than the predominately winter analysis shown in MH-21 (CEC Review of Bipole III) which assumed 900 MW of imports during the winter months. The MISO region is strongly summer peaking and Manitoba Hydro has no capacity import contracts from the MISO region in the summer. In fact Manitoba Hydro has significant summer capacity export contracts into the MISO region, which were assumed to be curtailed on an emergency basis for this analysis. The potential curtailment of up to 1,000 MW of the Manitoba load in summer highlights the importance of Bipole 3 to reliability of supply in Manitoba in summer.

Although less severe than the winter period, clearly there would be a shortfall of supply during the summer months for extended periods in the event of a Bipole I and II loss. This shortfall would increase with domestic load growth. Mr. Bowman's conclusion to allocate Bipole III costs, including Riel, based on either a CP or marginal cost Weighted Energy allocator constrained only the winter peak and shoulder periods (MIPUG, p. 32) is based on the incorrect assumption that Bipole III is only required for reliability during the winter period.

Figure 3: Hourly Manitoba Demand for Summer 2015

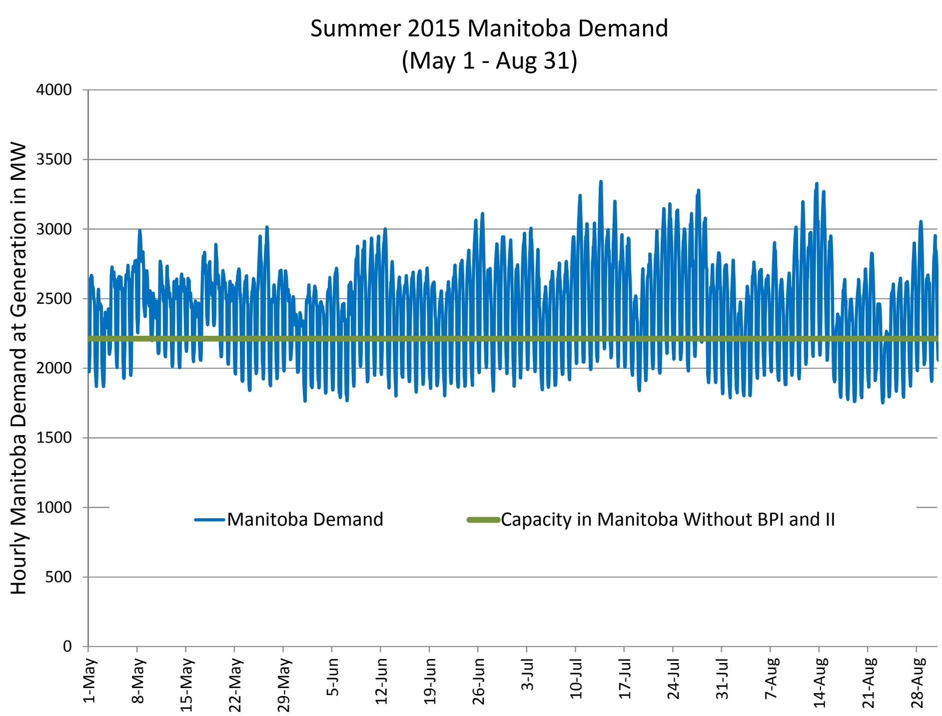
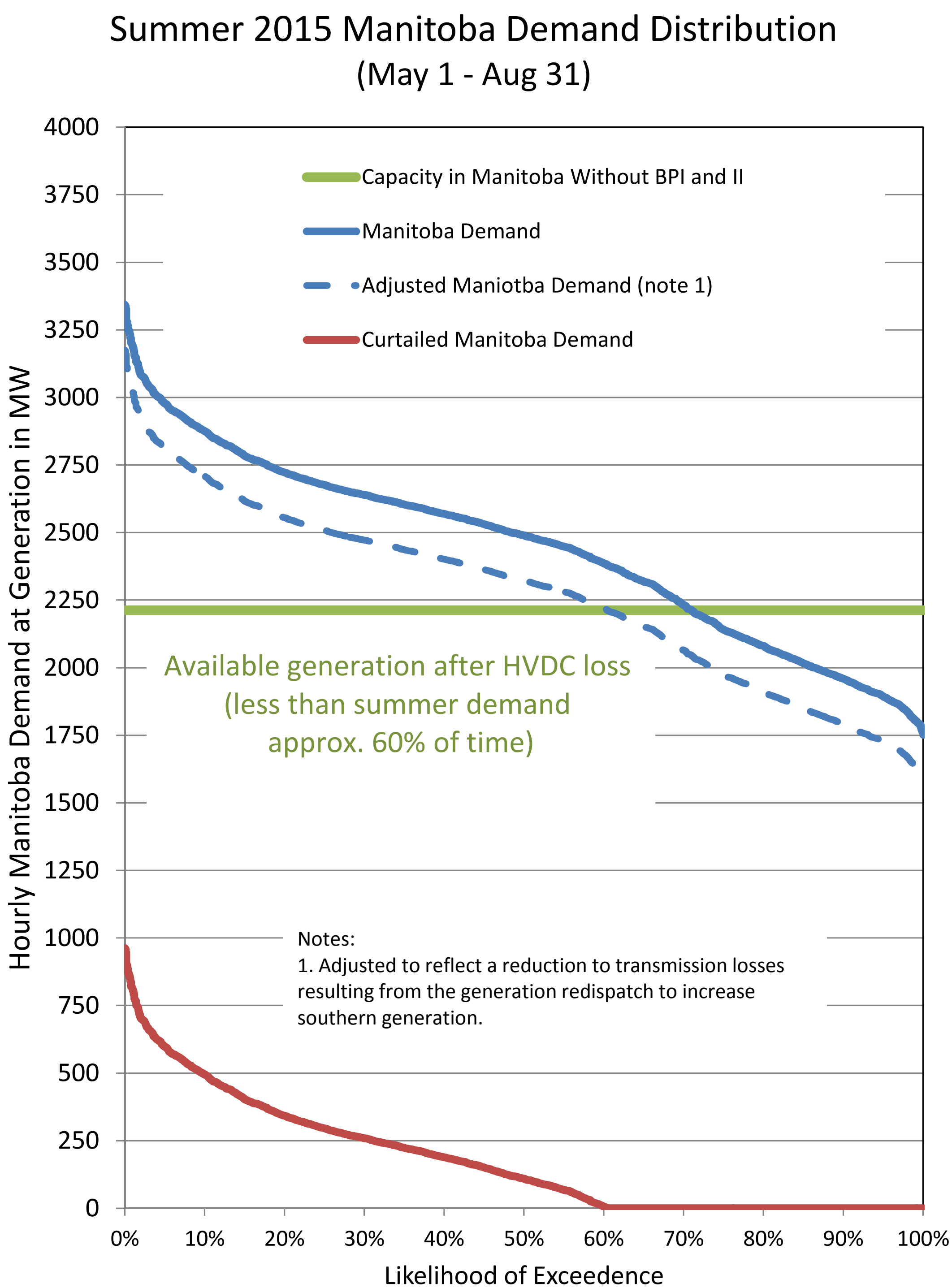


Figure 4: Summer 2015 Manitoba Demand Distribution



4 THE FUNCTIONALIZATION OF DORSEY IS CONSISTENT IN THE COSS AND OATT

During the proceeding Mr. Bowman raised the issue of a potential discrepancy between the functionalization of Dorsey convertor station in the COSS and the treatment of the station in Manitoba Hydro's OATT.

> "*Now, there's one (1) small detail that I don't think it turns on, but there is some conflicting evidence as to whether the Dorsey converter is included in Hydro's transmission tariff, the one that they are -- use to charge people who use Hydro's transmission system, third parties.……When we look at the numbers, it would still appear that it's included in the transmission tariff. In other places, Hydro has said that it's no longer included in the transmission tariff, and we haven't gotten that whole story. That's something we'd -- we'd like to explore as we get closer to the hearing.*" (Transcript pages 121-122)

Manitoba Hydro uses the PCOSS to determine the revenue requirements for the Manitoba Hydro Open Access Transmission Tariff (MH-OATT) rate calculations. The 2016 MH-OATT rates used PCOSS14 to determine the revenue requirement for the tariff. The 2016 MH-OATT rates include recovery of the costs of Dorsey (including the Dorsey Converters) since the entire station was functionalized entirely as Transmission in that study.

In their initial 2012 Report, CA recommended Manitoba Hydro review the COS approach which functionalized Dorsey Station as 100% Transmission. After further review, Manitoba Hydro agreed with the recommendation that the primary role of the HVDC facilities situated at Dorsey (and Riel) are dedicated to the Bipole facilities for the interconnection of generation and to inject power to the transmission system. Under the PCOSS14-Amended methodology 100% of the Dorsey (and Riel) HVDC facilities have been functionalized as Generation.

Manitoba Hydro expects that once the next PCOSS is released, the tariff rates will be updated to reflect that change during the regular OATT rate update. The MH-OATT will not include recovery for the costs associated with the Dorsey (and Riel) converters once the change is made in the PCOSS, and a new tariff rate is developed. Tariff rates are updated annually.

5 INTERCONNECTIONS ARE NOT THE SAME AS DOMESTIC NETWORK TRANSMISSION

At page 33 of his evidence, Mr. Bowman rejects Manitoba Hydro's adoption of Christensen Associates recommendation regarding Classification and Allocation of US Interconnections on the basis of Weighted Energy. Mr. Bowman rejects this treatment on the basis that in his view the practice is inconsistent with longstanding industry practice where Transmission assets are classified as capacity and further on the basis that it is inconsistent with the CP treatment of Manitoba Hydro's OATT.

Mr. Bowman's evidence ignores the role of these facilities which is to make generation available from one Spider Web to another Spider Web (Dr. Swatek, Transcript page 390 from Manitoba Hydro Workshop) in order to optimize both planning and operating power supply across the interconnected systems. This involves exchanges of energy at all times of the day and all seasons of the year. For example, Manitoba Hydro exports tend to occur more in the summer than in the winter and more in the peak period to take advantage of pricing. Imports tend to occur more in the winter than in the summer and more on the off peak period to take advantage of lower energy prices.

Additionally, even if you consider the OATT as relevant in terms of the purpose of these lines, Manitoba Hydro's tariff recovers cost based on 12CP. A 12CP allocator, consistent with cost recovery through Manitoba Hydro's OATT, results in a COS outcome close to a Weighted Energy allocator as shown in the table below:

Table 7: Comparison of Class Share's: Weighted Energy Allocator, 12CP and 2CP

Customer Class	PCOSS14-Amended Weighted Energy Allocator	12CP	2CP
Residential	29.0%	30.0%	32.8%
General Service - Small Non Demand	6.3%	6.6%	7.0%
General Service - Small Demand	7.9%	8.0%	8.3%
General Service - Medium	12.2%	12.5%	12.7%
General Service - Large 0 - 30kV	6.4%	6.6%	6.6%
General Service - Large 30-100kV	4.7%	4.4%	4.1%
General Service - Large >100kV	16.9%	15.3%	14.3%
Area & Roadway Lighting	0.3%	0.3%	0.2%
Export	16.2%	16.4%	14.0%

SECTION 2: ISSUES NOT SUBJECT TO ORAL HEARING

6 SUBTRANSMISSION

6.1 Manitoba Hydro's Separation of Radial Subtransmission is Appropriate to the Design of its System and the Requirements of its Customers

Manitoba Hydro functionalizes transmission facilities into two main groups: Transmission and Subtransmission. Transmission is defined as facilities operated at above 100 kV. The vast majority of Transmission assets are grid transmission, which is the backbone system which links generation facilities and major load centres and over which power can flow in either direction. A small proportion of Transmission is radial, i.e. power flows in only one direction and toward load. Subtransmission consists of those facilities which are operated at between 30 and 100 kV. Power flow is radial, moving power from the grid to regional transformation facilities. The subtransmission system was specifically designed to support the distribution system and to supply a small number of General Service Large customers (approximately 40) directly.

On behalf of GAC, Mr. Chernick's evidence is, essentially, that the Transmission and

Subtransmission system is a single unitary system and that the lines and substations of one are complementary with the other. "*…the <100-kV equipment represents an economic alternative to higher-voltage transmission, rather than an incremental cost*" (page 39:11-13). Therefore, according to Mr. Chernick, Subtransmission should be folded into the Transmission function and, by extension, the GSL customers served at voltages in excess of 100 kV should share in the cost of the Subtransmission.

Mr. Chernick provides four reasons why the subtransmission facilities and Transmission facilities should be treated as one function (pages 38 and 39 of his evidence). Two of these are flawed and for the other two, combining Transmission and Subtransmission is an inappropriate and unnecessary remedy.

1. According to Mr. Chernick, the transmission and subtransmission systems make up a single unitary system. This is not generally true. While loads and development vintage make it possible to serve some regions of the province without grid transmission >100 kV, the more normal case is that distribution stations and customers served by the subtransmission system are also served upstream by the main grid transmission system.
2. Mr. Chernick states that "*a substantial portion of the Distribution load does not use <100 kV facilities for power delivery*." While Mr. Chernick is correct in noting that some distribution customers are served with transformation that converts transmission voltage directly to distribution voltage, this does not comprise the majority of all distribution customers. The reality is that a large percentage of distribution customers are served from portions of the distribution system that are supported by subtransmission lines and stations that convert subtransmission voltage (i.e. 33 kV/66 kV) to distribution voltage levels (i.e. <30 kV). In those cases where distribution customers are served from substations that convert direct from transmission voltage, Manitoba Hydro incurs costs for transmission voltage to distribution voltage reductions. On the other hand, customers who accept service at voltages > 100 kV bear the cost of transformation to their utilization voltage.

3. Some generation is connected through <100 kV transmission. While it is true the Pointe du Bois Generating Station (75MW) is connected to the grid via <100 kV, this is not a basis for integrating the Transmission and Subtransmission functions but, rather, as Mr. Chernick himself states (in footnote 29 on page 38) for recognition of those lines as Generation related.
4. Similarly, Mr. Chernick's observation that radial taps with a total annual cost of $211,000 are currently allocated to all customers is not a basis for integrating Transmission and Subtransmission functions entirely, but rather for making the appropriate direct assignment of cost.

Allocating Subtransmission costs to the GSL >100kV class for assets they do not use has a material impact on their RCC as shown in the table below.

Table 8: Change in RCC when Subtransmission allocated to all Domestic Customers

Customer Class	Subtransmission allocated to all Domestic Classes	Change compared to PCOSS14-Amended
Residential	100.7%	0.8%
General Service - Small Non Demand	108.7%	0.7%
General Service - Small Demand	105.3%	0.8%
General Service - Medium	100.0%	0.7%
General Service - Large 0 - 30kV	91.7%	0.6%
General Service - Large 30-100kV	100.7%	0.9%
General Service - Large >100kV	94.2%	-4.3%
Area & Roadway Lighting	100.6%	0.3%

7 DISTRIBUTION

Manitoba Hydro classifies Distribution Substation costs as 100% Demand-related and allocates them on the basis of class Non-Coincident Peak demand. On page 57 of his evidence, Mr. Chernick questions the use of NCP as an allocator and proposes that *"Hydro should estimate the contribution of each class to the most constrained loading (i.e. the hours when load on the substation is the highest of its seasonal rating) on each substation, or a representative sample of substations. The resulting allocator should reflect the variety of seasons and times at which substations peak."*

While there may be some merit in exploring the alternative allocation procedure recommended by Mr. Chernick this needs to be considered in light of available resources, timing, and materiality of potential RCC changes. One of Mr. Chernick's arguments against NCP is that all the distribution classes in 2011/12 peaked in January, but a substantial share of distribution substations peaked in the summer months. However, a cursory review of the data supplied in response to GAC/MH 1-13 shows that the vast majority of distribution stations peak during one of the winter months. Consequently an analysis such as that suggested by Mr. Chernick may not yield results which are substantially different than using NCP. For illustrative purposes, Manitoba Hydro has re-estimated the allocation of Distribution Substation and the Demand portion of Poles & Wires based on a 75/25 Winter/Summer CP allocator which would represent the most significant change in class RCCs that could be reasonably expected. The results are provided in the table below.

Table 9: Change in RCC if Weighted CP used to Allocate Demand portion of Distribution

Customer Class	Distribution Stations on Weighted CP (75/25)	Demand Portion of Distribution P&W on Weighted CP (75/25)	Total RCC Impact of Weighted CP (75/25)
Residential	0.4%	0.6%	1.1%
General Service - Small Non Demand	-0.2%	-0.3%	-0.5%
General Service - Small Demand	-0.4%	-0.6%	-1.0%
General Service - Medium	-0.8%	-1.1%	-1.9%
General Service - Large 0 - 30kV	-0.8%	-0.6%	-1.3%
General Service - Large 30-100kV	0.0%	0.0%	0.0%
General Service - Large >100kV	0.0%	0.0%	0.0%
Area & Roadway Lighting	1.2%	1.6%	2.8%