MANITOBA HYDRO COST OF SERVICE STUDY METHODOLOGY REVIEW

MIPUG WRITTEN SUBMISSION
ON ISSUES NOT SUBJECT TO ORAL HEARING

August 12, 2016

INTRODUCTION

This written submission of the Manitoba Industrial Power Users Group ("MIPUG") is submitted in regard to the Manitoba Public Utilities Board ("PUB" or "Board") review of Manitoba Hydro's ("Hydro") Cost of Service (COS) Study. The submission has been prepared in accordance with Board Order 84/16 to address matters not included in the scope of the Oral Hearing, scheduled for September.

The following issues are addressed in this submission:

1. Coal Generation
2. Wind Generation
3. Curtailable Rate Program
4. Subtransmission
5. Customer Service (C10)

For clarity, in accordance with the Board's Order 84/16, this submission does not address any topics related generation (except coal and wind), transmission, DSM, the number or structure of the export class(es) and which costs would be allocated to exports, as well as the potential treatment and uses of Net Export Revenue (including alternatives such as funding Uniform Rates and the Affordable Energy Fund).

This submission has been prepared on the basis that Hydro's Cost of Service methods are a matter of significant importance to the regulatory review of Hydro's rates, and consequently are within the authority and jurisdiction of the Board. As such, Hydro's use of COS methods, and proposals to revise COS methods, must always be viewed in light of previous Board decisions, and absent updated or new findings from the Board, the previous Board findings remain the definitive methods for calculating Hydro's cost to serve each of its customer classes (i.e. at this time Decisions 117/06 and 116/08).

The present proceeding would have been materially aided if Hydro had taken this same view – that is, produce a full and proper analysis of the Cost of Service using all of the same methods and procedures as last reviewed by the Board (adjusted for those matters that the Board found required change), and then moved on to present Hydro's itemized list of proposals to alter the methods to reflect new facts, method improvements, etc. As this did not occur, the following submission makes a best-efforts attempt to remain consistent with the principle that the last Board approved methods are the starting point for regulatory review. In some areas this was difficult to reconstruct.

The fundamental principle for Cost of Service analysis is cost causation[1] reflecting the economic identity of the asset or cost in question[2]. MIPUG views that a proper and defensible Cost of Service study is required as an input in the rate making process.

MIPUG disagrees with Manitoba Hydro's view that Cost of Service should be the stage where one "balances other ratemaking objectives it seeks to achieve"[3]. Such a principle opens the door to excessive discretion on matters such as "competitiveness" or "gradualism" or "efficiency" (all objectives Hydro cites for its Cost of Service study[4]) and leads to an undermined or analytically indefensible Cost of Service study. The issue of such non-cost factors is addressed in the seminal literature on the subject of Cost of Service (the NARUC Cost Allocation Manual) as follows:

> Cost of service studies are among the basic tools of ratemaking. While opinions vary on the appropriate methodologies to be used to perform cost studies, few analysts seriously question the standard that service should be provided at cost. Non-cost concepts and principles often modify the cost of service standard, but it remains the primary consideration for the reasonableness of rates.[5]

In short, non-cost concepts (such as efficiency, competitiveness) can be considered as inputs to ratemaking in coming up with the design of the individual rates to be charged (a later step in the full regulatory process, coming after the Cost of Service study). This does not eliminate the need for a principled Cost of Service as a similar input to the

[1] E.g., see Hydro's filing Appendix 5 (the 2012 Christensen report), page 2.
[2] See MIPUG-11 Pre-Filed Testimony of P. Bowman, June 10, 2016, section 2.3.
[3] Manitoba Hydro Cost of Service Methodology Review Submission, December 4, 2015, page 2.
[4] Manitoba Hydro Cost of Service Methodology Review Submission, December 4, 2015, Section 4: Cost of Service Goals, pages 6 - 8
[5] National Association of Regulatory Utility Commissioners (NARUC), (January, 1992), Electric Utility Cost Allocation Manual, Chapter 2: Overview of Cost of Service Studies and Cost Allocation, page 12

ratemaking process. Mixing non-cost concepts into the Cost of Service study, as proposed by Hydro, is a complicating factor, undermining the production of an analytically defensible Cost of Service study, and leading to confusion over the role of each step in the ratemaking process.

ISSUE TOPIC #1: Coal Generation Allocation

ISSUE:

Should the costs of coal generation (Brandon Unit 5) be allocated only to exports, only to domestic customers, or a combination?

MIPUG RECOMMENDATION:

Coal generation is specifically excluded by legislation (Bill 15) from being used to support exports. As such, the costs of coal generation should not be allocated to export customers, but only domestic customers. The Board should direct that the previous Board-approved methodology (coal generation fixed costs assigned 50% to exports, and 100% of fuel costs to exports, per Order 116/08) be varied.

DISCUSSION AND SUPPORT:

The energy needs of Manitoba are met in normal circumstances from renewable generation, though additional generation resources such as thermal are available in specific conditions including drought. One of these resources, the Brandon Unit #5 coal plant, may be used only consistent with stipulations contained in Bill 15. Specifically, the legislation indicates that the generation cannot be used for export purposes after December 31, 2009[1].

For this reason, Hydro altered the Board-approved method, which involved directly assigning coal generation to exports[2] in PCOSS10[3]. Instead of any direct export assignment, in that PCOSS10, Hydro used a domestic only allocation. However, in PCOSS14-Amended Hydro has proposed a further adjustment, to a blended allocation, as follows:

[1] PUB-MFR-10, PCOSS10, page 7
[2] The method used in PCOSS06 and PCOSS08
[3] PUB-MFR-13

> Coal-fired generation, by virtue of Bill 15, can no longer be used to support exports and is therefore appropriately assigned only to Domestic load. However, to avoid introducing additional complexity with only minimal RCC impact, Manitoba Hydro is prepared to include these costs in the generation pool to be allocated to both Domestic load and Dependable exports.[4]

In short, Hydro cites that the appropriate treatment for Brandon Coal is to exclude export customers, but argues that the cost is small and any effect is minimal. Hydro does not clarify however why, if the effect is minimal, it is seeking a change today compared to the Board-approved methods.

The justification for why the Brandon coal plant was originally planned and built no longer provides a basis for assigning costs given a change to its economic identity. The purpose and role underpinning Brandon's economic identity at this time, and for which it is being retained in service, is as insurance for domestic customers, as explained by Mr. Bowman during the intervener workshop:

> Brandon coal is effectively not being used in the cost of service study because the cost of service study's based on an average water year. The coal plant is only there pretty much to back up extreme droughts.
>
> It's not being used for what it was built for in the '50s. That was an entirely system, what it was built for. It has some different economic identity now on the system. And that different economic identity is basically the insurance. And it's insurance for only domestic customers. It does nothing for exports. We can't export the power.

[4] Appendix 1, Manitoba Hydro's Response to the Recommendations (of Christensen Associates), page 4.

> We have a law that says we can't export the power, even though again at a use level you can't say which kilowatt hour went where.
>
> The only time you'd be allowed to turn that on and be able to use it consistent with that -- that legislation is if there was a severe drought in Manitoba, and as a result only domestic customers should be paying for the Brandon Coal Plant. It shouldn't be allocated to the export class. And that's one (1) of the recommendations in our -- in our -- in the -- the submissions.
>
> So, you know, for -- in that case you can't just look to the -- the -- any role that it had a long time ago. You have to look at why it's being maintained.[5]

The cost of coal generation in PCOSS14-Amended is material at $29 million[6]. At this level, Coal generation is a larger line item than either Uniform Rates ($23.5 million) or the Affordable Energy Fund ($12.8 million)[7], both of which have been determined to be large enough to merit considered treatment in the Cost of Service study.

There appears to be no reasonable rationale to assign costs of coal generation to export customers as the causality and economic identity is legislated for domestic use only.

There also appears to be no rationale to consider coal generation costs to be insufficiently large to merit specific consideration. If that were the case, there would be no basis to overturn the past Board-approved methodology. Further there would be no reason to merit review of such matters as Uniform Rates and Affordable Energy, which would similarly be insufficiently large to need

[5] Intervener Workshop Transcript, June 21, 2016, pages 113 - 114
[6] PUB/MH-I-70a-c, page 2.
[7] PCOSS14, page 6.

consideration (and as such should simply be reflected in the classes that they affect without further complicating the Cost of Service study).

ISSUE TOPIC #2: Wind Generation Classification and Allocation

ISSUE:

Should wind generation continue to be assigned 100% to exports consistent with the Board-approved methodology, and if not, how should wind generation be classified to energy and demand?

MIPUG RECOMMENDATION:

MIPUG recommends that wind generation not be assigned 100% to exports. Wind should be allocated among domestic and all export customer classes, on the basis of 100% energy, using marginal cost weighted energy (E12 as used in PCOSS-14, without the capacity adder introduced in PCOSS14-Amended).

DISCUSSION AND SUPPORT:

The proper treatment of wind resources requires consideration of two factors:

1) Should wind continue to be allocated 100% to exports?
2) How should wind be classified and allocated (i.e., should there be a demand component? weighted energy? etc.)?

Should Wind be Allocated 100% to Exports?

As an energy resource, wind is a complement of the annual production that supports the ability to make both domestic and export sales[1].

At the time of the previous Board Orders on Cost of Service (117/06 and 116/08), the Board concluded that wind should be assigned directly to exports[2]. The

[1]See Appendix 1: Manitoba Hydro's Response to (CA's) Recommendations, December 4, 2015, page 4 - where Hydro notes in respect of wind and other resources: "these resources serve all loads under some conditions."
[2] PUB-MFR-13; Board Order 117/06, page 25.

rationale was stated that resources "related to purchased power, including wind and Wuskwatim, [are] not expected to be required to meet domestic load out ten to twenty years"[3]. This is not the case today. The cited resources are no longer a conceptually marginal resource on Hydro's system, and further new resources (such as DSM and Keeyask) are now being pursued as required for domestic and export purposes.

For this reason, purchased power costs relating to wind purchases should be allocated to all domestic and export loads. Further, wind generation is specifically comprised of both dependable and opportunity energy[4]. Consistent with MIPUG's position on the design of the export class, all loads (domestic, dependable exports and opportunity exports) should share in the wind costs.

How Should Wind be Classified and Allocated?

In the 2012/13 Power Resource Plan and the more recently provided update for 2014/15, existing wind resources (a form of purchased power) provide no system firm peak capacity[5]. For this reason, wind should not be classified to demand, but 100% to energy.

The remaining issue is which energy allocator to use. MIPUG submits E12 (marginal cost weighted energy) is appropriate as this concept is used in the original PCOSS14 (i.e. without the capacity adder Hydro included in the methodology for PCOSS14-Amended).

A significant point of debate and confusion in the current proceeding relates to the meaning inherent in the E12 allocator. This allocator is fundamentally based

[3] Order 117/06 page 25.
[4] Coalition/MH-I-59b
[5] As noted in MIPUG-11 Pre-Filed Testimony of P. Bowman, June 10, 2016 on page 19 and found for example, in the 2012/13 Power Resource Plan filed as part of the NFAT proceeding or updated in Appendix 11.48 of the 2015/16 GRA. Also see PUB/MH-I-23a, page 4.

on all energy used by each class. However, the allocator also considers each kW.h not as an undifferentiated product, but as being of differing relative value depending on the time of day and time of year it is consumed[6]. This is consistent with the concept of energy values traded on a non-firm basis in energy markets, and indeed the E12 weightings are fundamentally developed based primarily on such non-firm energy market values[7].

The question that is outstanding is whether E12 inherently includes a firm reliable peak capacity component. If it does, it is not an appropriate allocator for wind. If it does not, then E12 can be an appropriate allocator for wind.

There are two versions of the E12 allocator available for the fiscal year ended March 31, 2014. The first was in the original PCOSS14, while a new version was included in PCOSS14-Amended. The new version was explicitly designed to attempt to insert added capacity considerations into the allocator[8]. Regardless as to the success of this attempt, the E12 allocator used in PCOSS14-Amended is consequently not advised for wind generation.

The E12 allocator used in the original PCOSS14, however, did not incorporate any special capacity related adjustments. That allocator was developed “based on the marginal value of electricity in 12 different periods”[9], solely on the short-term market prices[10].

[6] MIPUG-11, Pre-filed Testimony of P. Bowman, June 10, 2016, Section 3.1.2, page 20.
[7] Workshop transcript May 11, page 134. Ms. Derksen clarifies that SEP pricing used for determining the marginal cost weightings at most times is based on the “opportunity cost” of selling kW.h into the non-firm MISO market. At other times it can be based on variable costs of running thermal generation or import purchases, both of which are similarly non-firm market values.
[8] Manitoba Hydro Cost of Service Methodology Review Submission, December 4, 2015, page 20
[9] Manitoba Hydro Cost of Service Methodology Review Submission, December 4, 2015, page 8.
[10] Hydro COSS Workshop Transcript, May 11, 2016, page 153.

At its core, energy, even if it's like wind in that it's not firm and not backed by any dependable capacity, has a differing value depending on when it is delivered. This was confirmed by Hydro witnesses in the workshop transcript:

> MR. PATRICK BOWMAN: So even something that has no capacity does have a varying energy value to the system in different hours?
>
> MR. DAVID CORMIE: Yes.[11]

The same effect is true for the value of service provided to non-firm customers. If a wholesale load were to supply its entire needs from supplies within MISO on a basis without committed firm demand, the cost profile of that load would still be determined by the usage profile (daily, annual). A load that used significant power in higher cost hours would face higher costs than a load that used most power in lightly loaded off-peak hours. This is not a firm peak capacity effect – as the load has no firm peak capacity characteristics – it is solely an effect of varying economic characteristics of the customer load patterns.

In short, customers consuming power, including non-firm power produced from sources such as wind, have varying economic effects depending on which of the 8,760 hours a year the power flows. A very small number of those hours are the most severely constrained time periods, which can occur over a small range of acute load times (peak demand). Most other hours are not severely constrained, but still are higher cost to serve (direct cost or opportunity cost) than other hours. Although wind is a non-firm resource, and as such cannot be ascribed any guaranteed value associated with the highest peak hours, it is appropriate to allocate its costs to customers in recognition of the differing impacts and value of loads in differing hours throughout the remainder of the year. In short, the E12

[11] Hydro COSS Workshop Transcript, May 11, 2016, page 153.

allocator as used in the original PCOSS14 best suits the economic identity of the consumption of wind generation.

ISSUE TOPIC #3: Curtailable Rate Program (”CRP”) Cost Allocation

ISSUE:

Does PCOSS14-Amended appropriately reflect the costs and benefits of the CRP program?

MIPUG RECOMMENDATION:

Hydro’s proposed approach in PCOSS14-Amended for the CRP cost assignment and allocation is largely appropriate. However, due to a mathematical mismatch, in Hydro’s current PCOSS14-Amended, the customers participating in the Curtailable program end up burdened with large residual costs related to this program ($2.782 million). This is not a reasonable outcome.

MIPUG recommends an adjustment to Hydro’s proposed method in PCOSS14-Amended such that the amount credited back to curtailable classes (presently $5.766 million which is then allocated through energy allocator E12[1]) is increased to equal the amount charged (CRP revenue requirement $8.548 million[2]). This recommendation does not change Hydro’s proposed DSM methodology and is internally offsetting (the change would affect both the direct assigned amount and the E12 amount equally) so can be implemented without unbalancing the COS and without any other changes or offsets being required.

DISCUSSION AND SUPPORT:

The CRP is a Demand Side Management (DSM) program offered by Hydro that is distinct in its function compared to other DSM programs, in three ways:

[1] PCOSS14-Amended Schedule E1 Classified Costs by Allocation Table, page 2 of 2, Misc. Rev. reductions of $604,000 and $5,162,000.

[2] From DSM excel file, ‘Tables’ tab, sum of Curtail 30-100kV Curtail Prgrm Only and Curtail >100kV Curtail Prgm Only.

1) The program provides a benefit to Manitoba Hydro as a power savings contingency when required[3] and is largely about capacity, not about long-term energy[4].

2) The customer who participates receives a lower quality of power in exchange for the DSM funding. Most DSM programs are about the customer receiving a higher quality experience (e.g., a less drafty home, better resale value, better lighting quality, more efficient plant operations) as well as DSM program credits and bill savings.

3) According to Hydro, the program is designed to provide benefits almost exclusively over one year[5]. In this manner, the DSM costs/credits and the DSM benefits/value are basically designed to be matched within the year. In contrast, energy-focused DSM tends to focus on the long-term benefits of energy saving expenditures today.

The annual "cost" of the CRP program to Hydro is in practice a credit applied to bills, provided to the CRP customer for allowing their power to be interruptible ($5.766 million). The annual Revenue Requirement associated with the CRP program in any given year is the amortization (over 10 years), financing and taxation of this and all past CRP credits over Hydro's standard DSM accounting methods ($8.548 million in fiscal 2013/14). In PCOSS14-Amended, the higher annual revenue requirement value is the amount charged to participating CRP customer classes, while the lower annual cost is the amount credited back to CRP customer classes and charged to the systemwide customer use via allocator E12.

[3] See COALITION/MH-I-22g or PUB/MH-I-51

[4] In this regard, some utilities do not even consider their CRP programs to be DSM programming but instead simply a system supply cost.

[5] For example, see MIPUG/MH I-024a from the NFAT proceeding.

Hydro indicates the reason for the residual charge to CRP customer classes ($2.782 million over what is credited back) in PCOSS14-Amended is the result of the timing differences between the cost of capitalized program expenditures and the annual credits paid and that the size and direction of the net impact to the class will largely offset over an extended period[6].

However, the difference of $2.782 million is in fact largely the cost of financing the program credit (interest on undepreciated balance)[7] as well as capital taxes on the undepreciated balance. This amount will never be credited back to CRP customers as a credit applied to their bills, and is simply a result of Hydro's applied accounting treatment. It is not apparent why the CRP customer should be assigned 100% of the cost of financing the credit, particularly when the CRP program is an annual effect – the credit was paid in the year, and the systemwide benefit was received within the same year. There was no delay where the customer was paid before the benefits were actually received by Hydro[8].

The practical effect of the mismatch is fundamentally at odds with the very idea that participation in the program is solely a power quality benefit to the other classes (who, as a result of the program, are less likely to get interrupted at peak times) and a power quality detriment to the CRP participants[9].

[6] MIPUG/MH-I-16e

[7] A small effect would also be timing differences as to variances in the credit each year. Hydro's rationale for this gap focuses on the timing differences (MIPUG-MH-I-16e)

[8] This is in contrast to energy-focused DSM which operate to provide benefits over a longer-term despite costs being paid typically up front.

[9] In more precise terms, it is debatable whether the CRP classes should be assigned any of the costs of the CRP program since they fail to benefit from their own interruptions (i.e., arguably there should be an E12 allocator which includes all loads other than the CRP classes for the purposes of allocating the CRP costs – presently E12 costs are allocated to all classes including CRP classes - the effect however would likely be minimal and as such is not advised).

To resolve the material mismatch issue in PCOSS14-Amended, Mr. Bowman's Pre-Filed Testimony concludes that the annual revenue requirement of the CRP program that is directly charged to the participating classes should be offset by a transfer of the same full amount ($8.548 million) to the E12 allocator. This is a simple adjustment that is internally balanced (i.e., a net reduction to directly allocated costs, and an equal net increase to E12 allocated costs).

Hydro did not disagree with Mr. Bowman's evidence on the topic in the rebuttal evidence or offer any new commentary. During workshop discussion, Hydro admitted that it is an issue that was worth re-examining, but showed confusion over whether $8 million was actually a credit customers would receive at some later date:

> MS. KELLY DERKSEN: This is not clawing back the credit. It's a timing issue. They get the $8 million. They don't see it. They get it on their bill today, but they don't -- the – the benefit in -- from an accounting -- from a cost-to- service (sic) perspective isn't seen today. It's seen over time. So -- and -- and that's the disconnect.
>
> They see the benefit on their bill today, and through the cost allocation process, they don't necessarily see the full amount of $8 million today, but they will see it over time. So there's not -- there's a timing issue, but those equate, you know, over the – the length of the amortization period.
>
> …
>
> MR. PATRICK BOWMAN: So the only -- the only question then is you said that they receive the $8 million today. But as I understand these numbers, they receive the $5 million type of number today. The $8 million number only arises because it's got interest and --

and carrying costs because Hydro find -- find -- amortizes that amount. Really they're only seeing the five (5).

MS. KELLY DERKSEN: What we do is we provide these customers an offset to their bill each and every month. We add up that revenue, that – that reduction in that revenue that we give them every month, and that be -- we amortize that cost over time.

There's likely some carrying costs associated with having held that over time. And so there'll be a little bit lesser than the -- the $5 million, if -- if that's the number we agree that is provide -- or forecasted to be provided to these customers in that -- that year.

They will get perhaps, you know, slightly -- there's a -- a financing cost with that that will be added to their class that they will ultimately pay.

MR. BOB PETERS *(sic)*: So the -- we don't disagree that somewhere in the $5 million range is what they receive in the year. The -- the cost that's allocated to them is -- is higher than that because it's adv -- because it's -- it's amortized?

MS. KELLY DERKSEN: It's amortized and there's carrying costs attributed to that also, yes.

MR. PATRICK BOWMAN: The only question is, why wouldn't that final column have a number more like 8 million to keep them held whole and then that 8 million would become the cost allocated back on -- on

…

> MS. KELLY DERKSEN: You know, internally we had to digest this too, so this would -- this is probably an issue for a white board quite frankly.
>
> MR. PATRICK BOWMAN: We -- we continue to go through it. We have an IR that confirms that there's a -- a mismatch. It says that don't worry it should bounce over time. I think it's hard to tell someone, don't worry, you have 3 million in extra costs because you're in the program that you get a $5 million credit for.[10]

The confusion in the above transcript is because this issue is not in fact a matter of timing. The CRP customers who participate in the program will never receive the majority of the $2.782 million deficit[11] in PCOSS14-Amended as a credit to their bills in any form because it is interest and capital tax charges associated with the 10 year deferral of costs applied to all DSM programs[12].

Even though Hydro's position is that the CRP does not guarantee enduring benefits beyond the reliability achieved in the year a customer participates[13] the 10 year deferral simply arises as this period is used as an aggregate average for all DSM programs[14].

[10] Hydro COSS Workshop Transcript, May 13, 2016, pages 801- 804.
[11] For the 2013/14 year alone the interest and capital tax expense, both charges that will never be received by GSL >30kV curtailable customers in the form of a CRP credit, is equal to $1,676.5 million from the 'Tables' tab of the DSM.xlsx spreadsheet provided by Manitoba Hydro (sum of Curtail 30-100kV Curtail Prgm Only and Curtail >100KV Curtail Prgm Only - 165.2 thousand + 1,511.3 thousand).
[12] MIPUG/MH-I-16e
[13] PUB/MH-I-51 for example explains the CRP Reference Discount as being only 42% of the annual carrying cost of a SCCT for reasons including "is not guaranteed to exist in the long term"
[14] Hydro notes that: "Grouping the various DSM programs into the same category for amortization purposes recognizes that, on a consolidated basis, all rate payers in the Province benefit when multiple customer classes can participate in a variety of different programs. As such, one amortization period is used for all DSM programs to be consistent with the consolidated view of the overall benefit to the Province." MIPUG/MH-I-16c.

In short, MIPUG recommends that the Board direct the annual revenue requirement of the CRP program that is directly charged to the participating class should be offset by a increase in the transfer, to the full amount ($8.548 million) to the E12 allocator. The method should similarly be used in all future PCOSS studies for CRP costs.

ISSUE TOPIC #4: Subtransmission

ISSUE:

Hydro currently shares the costs of subtransmission (33 kV and 66 kV lines and the lower voltage parts of transmission substations) only among those customers who receive power at voltages at or below those that characterize the subtransmission system[1]. These costs are proposed to be allocated on the basis of Non-Coincident Peak.

Should subtransmission be allocated on the basis of Non-Coincident Peak to all classes whose loads are served at voltages at or below subtransmission voltage levels?

MIPUG RECOMMENDATION:

Hydro's proposed approach should be approved. Subtransmission costs should be allocated only to those customers who use the lines, being those who are served at voltages at or less than subtransmission voltage levels (66 kV, 33 kV). No allocation of subtransmission should occur to customers served at transmission voltages (>100kV)[2].

The use of Non-Coincident Peak (NCP) as an allocator for subtransmission is reasonable, justified and consistent with Cost of Service (COS) best practice.

[1] Manitoba Hydro Cost of Service Methodology Review Submission, December 4, 2015, page 11.
[2] The exception is cases where assets at 33 kV or 66 kV are deemed to be Generation Related Transmission Assets, in which case they would no longer be subtransmission, but would become generation assets allocated to all customers including >100 kV and Export.

DISCUSSION AND SUPPORT:

Subtransmission are those facilities described in PCOSS14 as follows: "These facilities are required to bring the power from the common bus network to specific load centres."[3]

The only party to take issue with Hydro's treatment of subtransmission was Mr. Chernick, expert for the Green Action Centre, who appears to recommend two changes:

1) That subtransmission should be allocated to all classes, including those served at voltages higher than the subtransmission system voltages, except export[4], or alternatively accepting Hydro's approach to not charge subtransmission to classes served at high voltages but additionally not charging subtransmission to a portion of customers who are in classes served at voltages at or below subtransmission voltages; and,

2) That subtransmission costs be allocated on the basis of Coincident Peak (perhaps weighted more heavily towards the winter) rather than Non-Coincident Peak.[5]

These are addressed separately below.

Allocation of Subtransmission Costs to Transmission (>100kV) Customers

Mr. Chernick's proposals on the matter of which customers should pay for subtransmission appear to have changed a number of times through the proceeding[6]. At its core, the proposals appear to rely on one of two factors:

[3] PCOSS14, page 23.
[4] Intervener Workshop Transcript, June 22, 2016, pages 628 – 632.
[5] Rebuttal Evidence of Paul Chernick, August 5, 2016, page 24 & 30.

1) Classes who are served at high voltages and that do not rely on subtransmission assets should still be allocated the costs of subtransmission assets (though this appears to only be true for the GS Large >100 kV class, not the export classes who are in the same situation); or alternatively,
2) If the GSL >100 kV class is going to be excluded based on not "using" the subtransmission (i.e., the >100 kV class), then large parts of the distribution system load should also be excluded as well since some distribution delivery locations happen to step down directly from transmission to distribution voltages with no use of subtransmission voltages.

Both of Mr. Chernick's premises are seriously flawed. In regard to (1) above, Mr. Chernick's position reflects a substantial misapplication of fundamental Cost of Service principles that customer classes would only be allocated costs for assets that relate to the power service being delivered to their class. In regard to (2), Mr. Chernick ignores the concept of a "class" defining the rates to be paid, not the concept of the costs to service an individual customer.

A fundamental and oft-quoted tenet of Cost of Service practice is that customers are not to be charged for assets that they do not use. In rebuttal evidence Mr.

[6] Mr. Chernick's position on this matter is inconsistent, as the original evidence indicates: "All transmission, from 30 kV up, should be allocated consistently: generation-related facilities on the generation energy allocators, other facilities on the 2 CP allocator." He later indicated under questioning from Mr. Harper at the June 22 workshop, that the lines over 100 kV should be allocated on a 2 CP basis to all customers including export, but that lines less than 100 kV should be allocated on a 2 CP basis, but only to domestic customers and not exports. Finally, in rebuttal evidence Mr. Chernick presumably recognized that >100 kV customers do not use the subtransmission system, and indicated that: "…if the Board were to decide to exclude the GSL >100 kV class from the cost of the subtransmission, the appropriate allocator would be 100% of CP for the GSL 30-100 kV class and 65% of CP for the distribution classes" at page 30.

Bowman notes this concept quoting from the NARUC Cost of Service manual as follows[7]:

> There is near-universal and longstanding agreement in COS best practice that customers served off of bulk transmission at high voltages should not be allocated the costs of lower voltage systems (such as subtransmission and distribution). For example, the NARUC Cost of Service Manual notes that: "Cost responsibility for subtransmission plant is usually assigned to only those loads served directly at the subtransmission voltages and those distribution loads fed through subtransmission facilities. Customers served at voltages higher than subtransmission are not allocated these costs on the theory that the subtransmission facilities are not required or used to provide the higher voltage services."[8]

Christensen Associates similarly reviewed Hydro's treatment of subtransmission[9] and concluded that: "high voltage customers should not be charged for the costs associated with subtransmission or substation facilities, and they are not under MH's current PCOSS methodology"[10].

Mr. Harper also commented in support of Hydro's treatment of subtransmission:

> Manitoba Hydro's separation of Sub-Transmission facilities recognizes that they are used solely to serve domestic load. In this role they are similar to Non-Tariffable Transmission except that the

[7] Rebuttal Evidence of Patrick Bowman, August 5, 2016, pages 16 - 17
[8] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, (January, 1992), page 73.
[9] Appendix 5 of Manitoba Hydro Cost of Service filings, CA Energy Consulting Review of Cost-of-Service Methods of Manitoba Hydro, June 8, 2012, page 16.
[10] Appendix 5 of Manitoba Hydro Cost of Service filings, CA Energy Consulting Review of Cost-of-Service Methods of Manitoba Hydro, June 8, 2012, page 15.

> facilities are not used to serve domestic customers with delivery voltages greater than 100 kV. Overall Manitoba Hydro's use and definition of a Sub-Transmission function is consistent with industry norms."[11]

In regard to the Cost of Service principle, even Mr. Chernick quotes the same principle of loads not paying for assets they do not use, or which do not serve them, in his recommendation to not charge subtransmission to export customers:

> MR. WILLIAM HARPER: Okay. And if we go sort of 41 and 42 pages, and I was trying -- maybe I'll just explain what I understand is, because at page 41 you indicate that all transmission from 30 kV up should be allocated consistently either as generation-related or as transmission using the 2CP allocator. Then on page 42 you go on to recommend that subtransmission, the allocation should include domestic, but not export loads. And so to clarify your proposal, you'd first remove -- take transmission. You'd first remove generation-related transmission assets, put them in generation. And then, for the remaining transmission costs, those above a hundred kV would be allocated to all domestic and exports?
>
> MR. PAUL CHERNICK: Yeah, I think that makes sense.
>
> MR. WILLIAM HARPER: And those at the sub-transmission level would be just allocated to just domestic --
>
> MR. PAUL CHERNICK: Right.
>
> MR. WILLIAM HARPER: -- using this allocator we've talked about?

[11] COALITION-15, Evidence of William Harper Econalysis Consulting Services, June 10, 2016, page 74.

> MR. PAUL CHERNICK: Yeah. I don't think any line under a hundred kV serves exports.[12]

Mr. Chernick offers no rationale for treating the GSL>100 kV class differently than the Export class on this test even though they similarly are not served by lines under 100 kV.

Further, Mr. Chernick cited no regulatory precedent or practice from other jurisdictions consistent with his proposal, and in fact indicated the opposite under questioning by Daymark stating that: "I -- you know, I don't know of anybody who's really addressed it in a formal way."[13]

A main consideration in respect of subtransmission is that these assets form a system that serves classes of customers who purchase a more premium product from Hydro: power at a lower voltage. For the GS Large >100 kV class, the product purchased is a less-refined bulk energy product that must be substantially transformed for use in their plant. Further, this bulk product can be delivered through use of the transmission assets, without use of the subtransmission system. Hydro's transmission witness explained the concept:

> DR. DAVID SWATEK: …We do have customers that are served off of the transmission, customers that are served off of 230 kV and one (1) -- 115 kV, and these large customers then have to invest their own capital in -- to build their own hub stations to get that 230 kV down to some useable voltage level.
>
> So they're -- they're purchasing the power wholesale off of the two thirty (230) and they're processing it themselves to get it to a useable voltage. Alternatively, we could do the processing through

[12] Intervener COSS Workshop Transcript, June 22, 2016, pages 628 - 629
[13] Intervener COSS Workshop Transcript, June 22, 2016, page 689

> a 66 kV to a lower voltage sub -- substation. We could process it through our own capital in -- investment and give the customer a product they can use without any further in -- investments on their part. So it's like a wholesale versus retail.[14]

The key aspect is that classes served at lower voltages make use of the subtransmission system, and further, as a result of that use, they receive access to a more refined, more "retail" higher value product.

Mr. Chernick's essential argument is not only unprecedented, it is also flawed. The argument hinges on the concept that voltage is an "arbitrary"[15] distinction for transmission assets (despite its widespread and standard use industry-wide) and that the subtransmission assets are not an "extra function" provided by Hydro, but that instead they are simply a part of a delivering power that actually serves to <u>reduce</u> Hydro's costs[16] and as such all customers should pay. If this were the case, Mr. Chernick provides no rationale why subtransmission should not be charged to all export customers as well, and further included in all transmission tariffs as tariffable assets (or in the extreme why this should stop at subtransmission and not extend to major distribution feeders, service drops, etc.).

In short, Mr. Chernick's original proposal that classes served at >100 kV should be charged for the subtransmission system has no principled basis for support. These assets are not required to serve the class. The >100 kV class is no different than export customers in this regard, who Mr. Chernick proposes to exclude from being assigned costs for the assets.

[14] Manitoba Hydro COSS Workshop Transcript, May 12, 2016, pages 521 - 522
[15] Rebuttal Evidence of Paul Chernick, August 5, 2016, page 23
[16] From the Rebuttal Evidence of Paul Chernick, August 5, 2016, page 21: "…the subtransmission equipment replaces the pricier high-voltage equipment in areas where that is feasible"

In apparent recognition of this principle, Mr. Chernick in rebuttal offers a new and alternative position, that the GSL >100 kV class could be excluded from being assigned the subtransmission assets based on non-use, but that similarly 35% of the distribution load should also not be allocated the costs. This apparent alternative rationale is that approximately 1/3 of distribution load is in areas where the voltages are stepped down directly from transmission voltages to distribution voltages[17] and hence does not have an intermediary step to a subtransmission voltage. The argument is nonsensical in relation to calculating the costs to serve classes (as opposed to individual customers) in a cost of service study (and particularly under Manitoba Hydro's requirement for Uniform Rates throughout the province), as noted by Mr. Bowman's rebuttal:

> Mr. Chernick's evidence also concludes that subtransmission should not be solely classified to customer classes served at lower voltages, as some of the customers within these lower voltage classes do not use the subtransmission system given the customer's particular geographic location. This ignores that Manitoba has a requirement for uniform geographic rates such that it is irrelevant whether an individual member of that customer class is in a location that happens to step directly down from high voltage transmission to low voltage distribution (i.e., with no subtransmission), or whether their location also has a step where mid-voltage subtransmission is used to deliver their power. An analogy might suggest that Vale in Thompson should not be allocated any costs of Bipoles I and II, being located in the north near the major generation, but this is clearly similarly not sensible and inconsistent with the Manitoba uniform rates requirement.[18]

[17] GAC-13, Evidence of Paul Chernick, June 10, 2016, page 40.
[18] Rebuttal Evidence of Patrick Bowman, August 5, 2016, page 17.

The most significant weakness with Mr. Chernick's alternative proposal is the entirely inconsistent manner in which Mr. Chernick deals with the idea that some distribution voltage customers somehow benefit Hydro ("saving Manitoba Hydro"[19] from costs) by electing to be served by subtransmission or not. In his first proposal, Mr. Chernick is effectively saying distribution voltage customers who happen to be served by subtransmission are the subset that is causing savings for the transmission system (e.g., the example of Bissett at pages 39 to 40 of Mr. Chernick's main Pre-Filed Testimony), while in the alternative proposal, Mr. Chernick is saying that the distribution customers who are not served from the subtransmission system but instead directly in a step down from transmission to distribution are the subset that is generating savings. The two arguments are internally inconsistent and without principle. The fact of the matter is customers in Bissett or any other location have not made an election in any manner to cause savings or costs to Hydro. An individual customer makes only 2 decisions: where to locate (build house, build industry) and, given connection costs and service needs, what voltage to be connected at (within a set of reasonable options). If the customer elects for high voltage (wholesale service) and the location can support that service, they are to be charged for the wholesale system. If they request retail voltage/service and the location can support that, they are to be charged the costs of the wholesale and retail systems. Beyond that, Hydro will design the most sensible and least cost system to serve all customer loads, and the customer has no further input or decision regarding the construction of the upstream combination of lines and substations bringing them power.

In short, Mr. Chernick's alternative option is further removed from principled Cost of Service practice than his original proposal, and should be similarly dismissed.

[19] Rebuttal Evidence of Paul Chernick, August 5, 2016, page 22.

Use of a 2 CP Allocator Rather than an NCP

Mr. Chernick's proposal to use a 2 CP allocator for subtransmission assets is not supported by any references to literature or precedent for this proposal. Hydro's approach of using NCP reflects industry standard methods, as cited by Hydro as well as Christensen[20] and Harper[21]. Hydro further concludes that the impact of any such change is very small (citing that: "illustrative impacts to RCC assuming 2 CP allocator weighted 75% to winter and 25% to summer peak do not materially impact cost depiction by class"[22]).

Hydro explained their approach as follows:

> MS. KELLY DERKSEN: From a cost allocation perspective, we treat subtransmission costs -- we classify them a hundred percent on the basis of demand. We allocate those costs based on each customer class's non-coincident peak.
>
> So that means, whenever that class peaks, regardless of when the rest of the system peaks, is how we allocate cost to that particular customer class. I understand that the use of an NCP allocator for transmission plant is quite common in the industry.
>
> CA has advised that it is appropriate to use NCP as an allocator for subtransmission cost. They have also advised that it might be appropriate that we investigate that further and reaffirm or otherwise the use of an NCP versus, let's say, a CP allocator.[23]

[20] Appendix 5 of Manitoba Hydro Cost of Service filings, CA Energy Consulting Review of Cost-of-Service Methods of Manitoba Hydro, June 8, 2012, page 16
[21] COALITION-15, Evidence of William Harper Ecoalysis Consulting Services, June 10, 2016, page 74
[22] MH-20 Manitoba Hydro Presentation for COSS Workshop, page 59.
[23] Transcript from Hydro workshop May 13, 2016, pages 652 - 654

There is little debate that assets in the form of wires and substations (e.g., transmission, subtransmission) should in almost all cases be classified to demand, and allocated on the basis of which demands drive highest peaks to be experienced. This could be coincident peaks for largely aggregated systems (like transmission) or non-coincident peaks for more distributed systems (like distribution). The approach taken by Hydro, to use NCP as the allocator for subtransmission, is reasonable.

However, the conclusion of Christensen in their 2012 report is also reasonable regarding the type of analysis that could support any future potential changes to use a CP allocator:

> To the degree that loads of subtransmission systems are: 1) highly correlated with the system peak demand, and 2) coincident peak demands are the basis for investment in subtransmission, MH should consider adopting a coincident demand related allocator for subtransmission. If the two conditions above are not true, then retaining an NCP allocator appears preferable.[24]

Based on the available information, NCP should be retained at this time as the allocator for subtransmission costs.

[24]Appendix 5 of Manitoba Hydro Cost of Service filings, CA Energy Consulting Review of Cost-of-Service Methods of Manitoba Hydro, June 8, 2012, page 16.

ISSUE TOPIC #5: Customer Service (C10) Allocation

ISSUE:

Hydro's PCOSS14-Amended allocates a $46.561 million in costs related to 'Customer Service' via the C10 allocator. Has Hydro's customer service costs been appropriately allocated to the classes, and in particular the industrial classes?

MIPUG RECOMMENDATION:

Hydro's C10 allocation results in GSL classes paying in full for the Customer Service departments serving large customers (Key Accounts and Major Accounts), as well as over $1.2 million of costs for customer service roles that relate to the smaller customer classes. The $1.2 million should not be allocated to GSL 30-100kV and >100 kV customers.

DISCUSSION AND SUPPORT:

The Customer Service General (C10) allocator was created in 2001 to recognize the different levels of customer service provided to each customer class[1]. The costs allocated via the C10 allocator total $46.561 million[2] and the ratios to be allocated to the various customer classes vary dramatically (for example, each residential customer is allocated costs as if they were 0.51 customers, while each GSL 30-100 kV Non-Curtailable customer is allocated as if they are 583 customers and each GSL 30-100 kV Curtailable customer is allocated as if they are 7,725 customers[3]). PCOSS14-Amended provided little details about what is included in this cost or how this weighted customer concept was derived.

[1] PUB/MH-I-4a

[2] MIPUG/MH-I-4a, page 5

[3] Per Daymark Model, tab "C Tables", C10 weighted ratio.

When asked for more detail Hydro provided the response to MIPUG/MH-I-4a which shows that C10 costs are initially made up of eight subcategories of costs generally associated with different customer service departments of Manitoba Hydro, specifically:

- Consumer Consultation and Information
- Municipal and Community Relations
- Public Accountability
- Power Quality
- Service Extensions
- Customer Policy
- Rates & Cost of Service, and
- Load Research

Of these categories, the largest by far, at over 67%, is Consumer Consultation and Information[4]. This category is allocated 9.7% to the GSL 30-100 and >100 kV classes[5]. No further information was provided in the IR responses to justify these figures.

During the workshop, Manitoba Hydro was requested to provide an undertaking to clarify what is included in the costs and allocation percentages for Consumer Consultation and Information. Undertaking Transcript page #791 provides this further clarification. This response shows that the category is further broken down to include:

[4] MIPUG/MH-I-4a, page 3. Note that the value shown at the bottom of this page (60.4%) is in fact a math error, as the sum of the values above is 67.3%, the same as the value shown in this column in the middle of the page. Also the final row in the table similarly does not sum to 100% as purported due to this error (which appears to relate to excluding the GSM component, at 7%).
[5] MIPUG/MH-I-4a, page 3, summed as 4.1% to 30-100 kV Non-Curtailable (which is made up of 39 customers per page 4 of that same response), 1.4% to 30-100 kV Curtailable (1 customer), 3.8% to >100 kV Non-Curtailable (14 customers) and 0.9% to >100 kV Curtailable (2 customers).

- Customer Engineering Services – Inquiries
- Customer Engineering Services – Inquiries Agricultural
- Energy Sales and Service – Consultations
- Key Accounts
- Major Accounts
- Common/Admin, and
- A generic category only referred to as “Customer Service” (despite the entire C10 category having been labelled as “Customer Service” to begin with, a sort of circular arrangement).

The generic “Customer Service” category makes up 65% of the costs in “Customer Consultation and Information”[6]. Of this category, combined GS 30-100kV and GSL >100kV are allocated 3.9%[7].

The only explanation provided for what is in this smaller Customer Service category was the following:

> Customer Service includes the costs related to line locates, safety watches, consumer consultations, building moves, and education/safety[8].

Despite requests at every opportunity to Hydro to further clarify this information, no further detail was provided.

In Mr. Bowman’s Pre-Filed Testimony, he addressed this matter on the contents of the smaller Customer Service category, noting:

[6] MH Workshop Undertaking from Transcript page #791, page 2. This is based on Planned Orders of $12.7 million out of a total of $19.4 million.
[7] Based on 2.0% to 30-100kV Non-Curtailable, 0.7% 30-100 kV Curtailable, 0.7% >100 kV Non-Curtailable, and 0.7% >100kV Curtailable.
[8] MH Workshop Undertaking from Transcript page #791, page 2.

> On a normal basis, few if any of these services would relate to services to industrials, who already are allocated substantial amounts for staff involved in the direct daily communication and consultation with these customers through the categories of "Key Accounts" and "Major Accounts". Certainly the information provided to date, through two rounds of information gathering, does not substantiate $1.2 million in allocated costs for these five generic services. Absent further compelling information from Hydro, there would appear to be no basis to allocate any of these costs to industrials.[9]

Mr. Bowman's Pre-Filed Testimony also noted the following in footnote 67:

> It further appears, from the response to Undertaking Transcript page 791, that the category is allocated by a gross estimation which simply forces 1% to each industrial subclass other than the GS Large 30-100 kV non-curtailable subclass which gets a generic estimate of 3%. It is not apparent that this is an allocation based on any reasonable allocation technique, such as number of customers, but despite requests, Hydro has not provided any substantiation for these values.[10]

The issue arises in respect of the list of services purportedly included in the smaller "Customer Service" category. Such issues as "line locates" (presumably the "call before you dig" services provided to homeowners and small contractors), building moves (in the context of customer service, would presumably relate to adjustments to service drops and customer accounts) and education/safety (as a customer service function would presumably relate to

[9] MIPUG-11, Bowman Pre-Filed Testimony, June 10, 2016, page 38-39
[10] MIPUG-11, Bowman Pre-Filed Testimony, June 10, 2016, page 39

information for homeowners about how to keep their electrical service in their home safe from small children and the like) are not relevant to large industrials, who make use of none of these services. Matters such as safety signage at generating stations would relate to service to industrials, but such assets would properly be included in generation costs (and already be allocated to industrials using the E12 allocator).

Despite the opportunity to clarify this issue in rebuttal evidence, Manitoba Hydro provided no further comment or information.

No other intervenor commented on the issue except Mr. Chernick who, although sympathetic to the issue of the poor information provided, concludes that the matter should be accepted as filed for today's purposes, and addressed in a future hearing as needed[11]. It is not apparent how this conclusion meets any reasonable regulatory threshold for an Applicant who has the onus to justify their case under scrutiny. It is also not apparent how Mr. Chernick concludes that any future proceeding will generate better information if Hydro is unwilling or unable to provide clearly necessary information to fully justify its case.

In sum, although every opportunity was provided Hydro to justify this $1.2 million cost allocation, solely generic information was made available. Further this information, on its face, is contrary to Hydro's case that these costs should be allocated to industrials. Manitoba Hydro cannot be granted the ability to provide wholly inadequate information in areas that are repeatedly requested, and still be assumed to recover over $1 million for industrial customers for operations which appear unrelated to industrial wholesale type services.

Given the failure to justify these costs, Hydro should be directed to exclude all C10 costs related to the "Customer Service" grouping from allocation to

[11] Rebuttal Evidence of Paul Chernick, August 5, 2016, page 34-35.

industrials. The net result of this change would be a slightly higher allocation to the distribution level classes of approximately[12] 0.1%.In the event Hydro seeks to include such costs in the industrial Cost of Service in future, it should be directed to provide full details on how the allocations were developed, and in what manner Hydro concluded that these services relate in any way to wholesale-level power delivery.

[12] $1.2 million on an approximately $1.2 billion total revenue.