MANITOBA PUBLIC UTILITIES BOARD

MANITOBA HYDRO

COST OF SERVICE

METHODOLOGY REVIEW

REBUTTAL EVIDENCE PREPARED BY

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FOR

CONSUMERS' ASSOCIATION OF CANADA (MANITOBA BRANCH)

WINNIPEG HARVEST

(THE CONSUMERS COALITION)

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1. INTRODUCTION

On December 5, 2015 Manitoba Hydro filed an Application with the Manitoba Public Utilities Board (MPUB) for review and consideration of its Cost of Service (COS) methodology. In a procedural order[1] issued February 26, 2016 the MPUB established the steps that would be followed in reviewing Manitoba Hydro's COS methodology which included the filing of information requests to Manitoba Hydro by intervenor and Board Staff; workshops to address both Manitoba Hydro's evidence and the evidence filed by intervenors; a delineation of those issues to be addressed by written submissions only versus those that would be subject to an oral hearing and provision for final submissions. In a subsequent procedural order[2] issued July 12, 2016 the MPUB revised the process to also include, following the workshops, rebuttal evidence by both Manitoba Hydro and intervenors on all issues.

In accordance with the July procedural order, the Consumers Coalition requested Mr. William Harper of Econalysis Consulting Services to prepare this rebuttal evidence. Also, in accordance with the MPUB's Order, the rebuttal evidence has been divided between the key issues subject to the oral hearing and those issues to be addressed through written submissions.

2. ISSUES SUBJECT TO ORAL EXAMINATION

2.1 TREATMENT OF DEMAND-SIDE MANAGEMENT (DSM) COSTS

2.1.1 Jurisdictional Comparisons

Both Manitoba Hydro[3] and Mr. Bowman[4] (on behalf of MIPUG) favour the direct assignment of DSM program costs to customer classes based on class participation. Their rationale is that it is the participating customers that caused the costs and who benefit most from the programs. However, Manitoba Hydro has acknowledged[5] that a good argument can be made for viewing DSM as a substitute for Generation and Transmission and treating it as such in the COS (similar to the proposal in Mr. Harper's

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[1] Order 26/16
[2] Order 84/16
[3] Appendix 3.1, page 11
[4] Evidence, page 6
[5] May 13, 2016 Workshop, page 645

May 2016 Evidence[6]). Similarly, Mr. Bowman acknowledges[7] that other utilities functionalize DSM as Generation (i.e. as a system benefit).

Mr. Chernick (on behalf of GAC) recommends[8] that the treatment of DSM costs should recognize that DSM programs provide both a system benefit and a benefit to participating customers and be allocated in a manner that balances these two "benefits". In his testimony[9] at the June Workshop Mr. Chernick offered one example of a utility that followed his recommended approach. He also took the view that there was no fundamental reason for preferring one approach (i.e., treating as a system benefit versus direct assignment to participating customer classes) over the other[10].

In their evidence both Manitoba Hydro[11] and Mr. Bowman[12] have relied on jurisdictional comparisons, and specifically a study recently prepared for BC Hydro by Leidos Engineering. Both have acknowledged that different approaches exist regarding the treatment of DSM, but neither has made reference to the Leidos study results on this issue.

Pages 3-18 to 3-20 of the Leidos study[13] provide the results of its jurisdictional review of DSM, energy efficiency and conservation program cost classification and allocation methodologies. The study's observations regarding the functionalization of DSM costs are as follows[14]:

> *The majority of the utilities functionalize 100 percent of these costs to generation. The other utilities allocate the costs to multiple functions using functionalization factors derived from other types of functionalized costs or savings such as administrative and general expenses, supply costs savings, and total*

[6] Page 45
[7] Evidence, page 41
[8] Evidence, page 18
[9] Page 618
[10] Pages 645-646
[11] Rebuttal Evidence, page 20
[12] Evidence, pages 12 and 23
[13] A full copy of the Study is provided as Attachment A. Original Study can be found at http://www.bcuc.com/Documents/Proceedings/2015/DOC_44664_B-1-BCH-2015-Rate-Design-Appl.pdf
[14] Page 3-20

functionalized O&M costs. For those utilities allocating costs to multiple functions, the ranges of amounts allocated to each function are as follows:

o Generation - 13 percent to 95 percent.

o Transmission - 2 percent to 10 percent.

o Distribution - 0 percent to 59 percent.

While the practice of other utilities should not be taken as determinative of what is appropriate for Manitoba Hydro, it is useful to understand the approaches adopted by others which can be particularly instructive in instances (such as DSM treatment) where it is acknowledged that there is more than one approach which could be considered appropriate.

Of particular note from the Leidos Study results is that:

- None of the utilities surveyed used either the direct assignment approach (recommended by Manitoba Hydro and Mr. Bowman) or the dual-allocation approach recommended by Mr. Chernick. Instead all of the utilities functionalized DSM costs and most did so just to generation.
- Overall, the treatment of DSM by all the utilities surveyed most closely matches that recommended by Mr. Harper.

2.1.2 Consideration of Non-Participant Impacts

Mr. Bowman's support for the direct assignment of DSM costs to customer classes is predicated, in part, on the fact it obviates the need for non-participating customer classes to be concerned about the potential impact DSM programs will have on electricity costs[15]. Similarly, Mr. Chernick's dual allocation proposal is aimed at addressing the potential bill impacts of DSM programs on non-participating customer classes[16]. As Mr. Chernick explains, DSM has three effects on revenue requirement and rates:

- It shrinks the size of the pie (i.e. revenue requirement) of non-DSM costs that need to be allocated among customer classes. Furthermore, since DSM is generally

[15] Evidence, page 42
[16] Evidence, page 19

undertaken only if less expensive than the avoided costs, the total pie (i.e., total revenue requirement) will also shrink in the long term.

- It reduces the loads for participating customer classes and thereby reduces their share of the revenue requirement pie.
- It, correspondingly, increases the portion to be allocated to other (non-participating) customer classes. The overall net effect of allocating a larger portion of a smaller revenue requirement to these classes may result in their total allocated costs either increasing or decreasing.

Manitoba Hydro's 2011 DSM Plan (filed in support the 2012/13 & 2013/14 GRA[17]) and its most recent 2014/15 Power Smart Plan (filed in support of Manitoba Hydro's Application for Interim Rates Effective April 1, 2016[18]) report Rate Impact Measure Test results of 1.2 and 1.0 overall for the respective Power Smart Plan portfolios. The fact the ratios are 1.0 or greater means that the benefits from the DSM program (i.e., increased export revenues and reduced infrastructure costs) equal or exceed the "cost" of DSM, including program administration and incentive costs as well as lost revenues due to reduced loads[19]. This would suggest that, over the long-term, there should be no material concern regarding the impact on non-participating customers.

2.2 NUMBER OF EXPORT CLASSES

2.2.1 Economic Perspective

Based on the evidence and testimony to-date there appears to be a general consensus that both dependable and opportunity exports have been a consideration in the investment decisions underlying the development of Manitoba Hydro's current generation facilities. This can be found in the following references:

- Manitoba Hydro's Rebuttal Evidence, pages 4-6;
- Mr. Bowman's Evidence, page 35;
- LEI Evidence, pages 6-8; and
- Mr. Harper's Evidence, page 31.

[17] Appendix 7.1, page 14
[18] Appendix 24, page 57
[19] Ibid, Appendix E

The key area of disagreement appears to be the degree (e.g. per kWh) to which dependable and opportunity exports should attract fixed generation and transmission costs relative to domestic load. Mr. Bowman's recommendation for one export class results in both dependable and opportunity exports attracting fixed costs on the same basis and to the same degree as firm domestic load. In contrast, Manitoba Hydro's proposal (supported by Mr. Harper) results in dependable exports attracting fixed costs on the same basis as firm domestic load while LEI's proposal results in dependable exports plus a portion of opportunity exports attracting fixed costs on the same basis as domestic load and, in each case, the remaining (opportunity) exports attracting no fixed costs at all.

As noted in Mr. Harper's testimony[20] the question as to the appropriate number of export classes can be approached using either cost of service principles or economic principles, where the later considers the economic basis for Manitoba Hydro investing in hydro-electric facilities, and that both perspectives are relevant. In his evidence Mr. Bowman suggests that since the purpose of introducing the export class (or classes) was not to set export prices, cost of service considerations (such as quality of service) do not apply and what is relevant is that exports (including opportunity exports) caused Manitoba Hydro to incurred generation costs[21].

In its Rebuttal Evidence[22] Manitoba Hydro has described how for much of Manitoba Hydro's legacy hydro generation the potential for opportunity exports was not taken into account by system planners. A review of the record regarding Manitoba Hydro's more recent decisions to advance the in-service dates for Wuskwatim and Keeyask also suggests that for these facilities, exports should not be attributed fixed costs on the same basis as firm load.

In the case of Wuskwatim, the information provided during the associated NFAT review indicated that:

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[20] June Workshop, pages 358 and pages 498-502
[21] Evidence, pages 35-36
[22] Page 29

a) The levelized cost of energy for Wuskatim compared favourably[23] to that of the gas-fired SCCT and CCCT gas-fired alternatives. This means that incremental cost (per kWh) for the additional generation capability provided by Wuskwatim (and which is available for export) is less than levelized cost of these alternatives. This, in turn, suggests that the incremental cost responsibility (per kWh) attributable to exports is less than that for firm domestic load[24].
b) The NFAT submission noted[25] that dependable exports are valued at a premium price relative to opportunity exports, indicating that (per kWh) dependable exports supported a greater investment in fixed costs than opportunity exports.

In the case of Keeyask, information provided during its NFAT review similarly indicated that the levelized cost of energy from Keeyask was less than the levelized cost for the other technologies considered[26]. This means that (again) the incremental cost (per kWh) of the additional generating capability provided by Keeyask (and available for exports) is less than levelized cost of the available generation alternatives and thus the incremental cost responsibility (per kWh) attributable to exports should be less than that attributed to domestic load.

As a result, even for the more recent hydro generation investments while exports (dependable and firm) supported the choice of plant, exports should not be attributed the same degree of fixed cost responsibility (per kWh) as domestic load. Combining

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[23] CAC/MSOS/NFAAT/S/1a. It is noted that the values shown in the referenced materials are based on a 10% real discount rate. Using a lower discount rate reflective of MH's cost of capital (6.08%) would further improve the relative economics of Wuskwatim.

[24].Where the levelized cost of a potential hydro facility is less than that of the other alternatives being considered, the key issue is the fact that not all of the energy the facility is capable of producing is dependable energy and, even when it is, it is not needed immediately to serve domestic load. The balance of the generation output is therefore available for export. In such situations, for the hydro facility to be viewed as economic overall, the (dollar per kWh) contribution from exports does not have to equal the levelized cost of facility but rather just be sufficient to ensure that the overall cost to customers is less than the next best alternative. As a result, the cost responsibility of exports will be less than the average cost of the facility. For example, assume the levelized cost of a potential hydro facility is $60/MWh and the levelized cost of the most economic alternative is $70/MWh. Assuming only 2/3's of the energy from the hydro-electric unit would be used to meet firm domestic load, this means that without export revenues, the effective cost of the hydro facility is really $90/MWh ($60/0.667 - setting aside the impact of lower variable costs). However, if export revenues exceed $40/MWh for the remaining 1/3 then the levelized cost per MWh used to serve firm domestic load will be less than $70/MWh ($60-($40*0.333)/ 0.667=$70), indicating that the cost responsibility attributable to exports ($40/MWh) is less than that attributable to firm load ($60/MWh).

[25] Attachment 6, page 6

[26] Chapter 7, Table 7.6

these observations with Manitoba Hydro's regarding earlier hydro investments, approach suggested by Mr. Bowman will overstate the cost responsibility attributable to exports even when only assessed from the economic perspective he has suggested.

3. ISSUES NOT SUBJECT TO ORAL EXAMINATION

3.1 DISTRIBUTION SUBSTATIONS

3.1.1 Use of NCP to Allocate Substation Costs

Manitoba Hydro proposes that Distribution Substations be classified as 100% demand-related and allocated using the NCP (Non-Coincident Peak) demand for each customer class[27]. In his evidence Mr. Chernick recommended that Manitoba Hydro undertake an analysis of the contribution of each customer class to the most constrained load on each substation and allocate the cost of substations accordingly[28]. However, recognizing that Manitoba Hydro does not likely have all the data required to perform such an analysis, Mr. Chernick recommends (as a default) that Distribution Substations be allocated using a 2 CP factor with summer weighted about 50%[29].

During the June Workshop[30] Mr. Chernick was asked to comment on the fact that the NARUC Cost Allocation Manual supports the use of NCP to allocate Distribution Substation costs and that it is not uncommon for utilities to use NCP. In his response, Mr. Chernick noted that NCP was an old technique and that the NARUC Manual was "showing its age".

However, Mr. Chernick did not address the second part of the question with respect to the current practice of utilities. As noted in Section 2.1.1 above, both Mr. Bowman and Manitoba Hydro have made reference to a recent jurisdictional survey performed by Leidos in their discussions regarding the classification and allocation of generation costs. This same survey also addresses the cost of service methodologies currently used by utilities with respect to Distribution costs, including Distribution Substation

[27] Appendix 3.1, pages 27 and 71
[28] Evidence, page 57
[29] Evidence, page 58
[30] Pages 679-680

costs. The results of the survey[31] indicated that six of the seven utilities[32] reporting their practices regarding Substations used NCP as their allocator, while the seventh used a method that also relied on the NCP allocator but at the individual substation level – similar to Mr. Chernick's preferred approach. This would suggest that utility practice regarding the allocation of Distribution Substations is still in line with the NARUC Manual and Manitoba Hydro's proposed use of the NCP allocator is reasonable.

However, it is also noted that the actual NCP allocator used by these six utilities varies, with three using a 1 NCP allocator and 3 using a 12 NCP allocator[33]. As a result, there would be merit in Manitoba Hydro reaffirming (through analysis of its load research data regarding customer class monthly load profiles) that 1 NCP continues to be the appropriate NCP allocation factor.

3.2 DISTRIBUTION POLES AND LINES

3.2.1 Classification of Distribution Poles and Lines

Manitoba Hydro proposes to continue to classify Distribution Poles and Lines as 60% demand and 40% customer[34]. In his Evidence[35] Mr. Chernick recommends that Distribution Poles and Wires (with the exception of Service Drops) be classified as 100% demand-related. Mr. Chernick's Evidence[36] cites a number of utilities that classify Distribution Poles and Wires as 100% demand-related and, then, goes to critique the Minimum-System Method, one of the approaches commonly used to classify distribution facilities.

With respect to the practice of other utilities, Mr. Chernick has acknowledged[37] that there are utilities that do not classify distribution poles and wires as 100% demand-related. This is supported by the Leidos Study which indicates that ½ of the utilities

[31] See Attachment A, pages 3-13 and C-13.
[32] It should be noted that one of the six utilities was Manitoba Hydro.
[33] The 1 NCP allocator would be based on the each class' maximum demand during the year, whereas the 12 NCP allocator would be based on the average of the 12 monthly NCP values. Also, it should be noted that one of the 3 utilities reported as using 1 NCP is Manitoba Hydro.
[34] Appendix 3.1, page 27
[35] Page 48
[36] Pages 49-52
[37] June Workshop, pages 634-635

surveyed classify a portion of fixed cost associated with Distribution Lines as customer-related[38].

With respect to the criticism of the Minimum-System Method, this is largely based on the fact that the minimum system established through the analysis is capable of carrying some demand and therefore does not separate out what would be considered strictly customer-related costs. However, utilities and regulators have addressed this criticism by determining the peak load carrying capability of the minimum system and incorporating an adjustment into the allocation process. Examples of this can be found in cost of service analyses performed by FortisBC[39] and Hydro One Networks Inc.[40] as well as the generic COS methodology approved by the OEB for general application to Ontario's electricity distributors[41].

As a result, there continues to be merit in the PUB directing Manitoba Hydro to undertake a review as to the appropriate split for poles and wires (and also transformers) between demand and customer-related costs.

3.2.2 Allocation of Distribution Poles and Wires

Similar to the situation with respect to Distribution Stations, Manitoba Hydro proposes to allocate the demand-related portion of Distribution Poles and Wires using 1 NCP; whereas Mr. Chernick recommends[42] the cost of primary poles and wires be allocated using a 2 CP approach with a 50% weighting for summer. Mr. Chernick's rationale is that many feeders serve more than one class and that even feeders serving primarily a single class peak at different times.

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[38] See Attachment A, pages 3-14 and C-14. Note- the ½ figure excludes Manitoba Hydro.
[39] http://www.bcuc.com/Documents/Proceedings/2009/DOC_23627_B-1_FortisBC%202009%20Rate%20Design%20Application.pdf – see Appendix A, page 19
[40] http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/11693/view/HONI_%20Appl_EDR2008_20080625.PDF – see Exhibit G2, Tab 1, Schedule 1, page 20 and Appendix B, page 2

[41] http://www.ontarioenergyboard.ca/documents/cases/EB-2005-0317/filingguidelines/Electricity%20Cost%20Allocation%20Guidelines%20Nov%2016%20FINAL.pdf – see page 30
[42] Evidence, page 58. Note – It is not immediately clear from the record whether Mr. Chernick proposes to also allocate secondary lines (which he would classify as 100% demand-related per June Workshop, page 640) using a CP or NCP allocator.

Again, while Mr. Chernick's rationale would suggest that NCP is not a perfect allocator for these costs it also suggests, since primary lines will peak at different times, that an allocation using a CP allocator would not be entirely appropriate either. Again, both the NARUC Manual and the recent jurisdictional survey undertaken by Leidos[43] indicate that most utilities favour using NCP as the allocator, suggesting that Manitoba Hydro's use of an NCP allocator is reasonable.

However, again, it is noted that the actual NCP allocator used by these utilities varies with some using 1 NCP allocator while others use a 12 NCP allocator. As a result, there would be merit in Manitoba Hydro reaffirming (through analysis of its load research data regarding customer class monthly load profiles) that 1 NCP continues to be the appropriate NCP allocation factor for the demand-related portion of Distribution Poles and Wires.

[43] See Attachment A, pages 3-14 and C-14