Manitoba Hydro

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September 28, 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 COST OF SERVICE STUDY METHODOLOGY REVIEW- MANITOBA HYDRO'S WRITTEN FINAL SUBMISSION

Please find attached Manitoba Hydro's Written Submission on Issues Subject to Oral Hearing as per the Revised Hearing Timetable issued by the Public Utilities Board ("PUB") in Order 84/16.

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 HYDRO'S FINAL ARGUMENT
WITH RESPECT TO ISSUES SUBJECT TO ORAL EVIDENCE
COST OF SERVICE METHODOLOGY REVIEW

INDEX

1.0 SUMMARY OF RECOMMENDATIONS

Manitoba Hydro is requesting the Public Utilities Board ("PUB") to find the following with respect to issues subject to oral evidence:

1) It is appropriate to functionalize the following asset groups as Generation:
    a. All Generating Stations
    b. Bipoles I, II, and III
    c. Dorsey and Riel convertor stations
    d. All Generation outlet transmission included as such in PCOSS14-Amended
    e. Additional Generation outlet transmission not currently identified as such in PCOSS14-Amended but recommended by interveners. These are listed on page 23 of Manitoba Hydro's Final Argument; they include some but not all of the facilities identified by Mr. Chernick on slides 21-23 of his September 8th presentation.
2) The Weighted Energy allocator with the Capacity Adder, as filed, is the appropriate method of classifying and allocating the cost of the Generation function. If the PUB is persuaded by MIPUG's argument that the Adder is spread into too many hours, it should find that, as an interim measure, the Adder be spread into the Winter and Summer Peak periods only pending further review.
3) SEP prices are an appropriate measure of Manitoba Hydro's short run marginal cost for use in the Weighted Energy allocator and do not require further review or refinement.
4) Grid Transmission assets, with the exception of U.S. Interconnections are appropriately classified as Demand-related and allocated on 2CP.
5) The U.S. Interconnections are appropriately classified as Transmission but because of their role in providing long term capacity and energy support to Manitoba load and as an outlet for surplus generation at both peak and non-peak times, their cost should be allocated on the basis of Weighted Energy including the Capacity Adder.
6) An Export Class should continue to be used in the Cost of Service Study to separate, as reasonably as possible, the costs reasonably deemed to be incurred to make exports from the surplus export revenue ("Net Export Revenue") provided by the market.
7) While it is not possible to precisely determine the costs incurred to make exports possible, Manitoba Hydro's proposed approach to allocate a full share of fixed costs to Dependable Exports and only variable cost to Opportunity Exports is reasonable and balanced.
8) Manitoba Hydro's proposed treatment of Net Export Revenue, that is, initial allocations to support the policy initiatives of Uniform Rates and Affordable Energy with the balance to be allocated on the basis of total cost is reasonable and fair and supported by the following:
    a. Government Policy and earlier PUB directives;

b. The fact that Net Export Revenue has no cost foundation and there is discretion to apply it in keeping with other cost of service and policy related objectives
c. All class revenues are required to support the development and operation of the Manitoba Hydro system
d. Strict allocation on the basis of class use of the assets that are used in making exports (that is, Generation and Transmission) ignores the fact that to a significant degree, export sales are possible because of the non-use of these assets by domestic customers (particularly, those served by the distribution system) at certain times of the day and year.
e. Allocation of Net Export Revenue on the basis of total cost produces more reasonable and stable class RCCs in the face of variations in export revenue, than one on the basis of only generation and transmission costs.

9) Direct assignment of DSM costs to the customer classes receiving the program benefits and bill reductions is both cost causative and fair to non-participating classes.
10) It is appropriate to allocate the full CRP Revenue Requirement to the generation pool to represent the benefits Curtailable customers provide to the system.

2.0 INTRODUCTION

On December 4, 2015, Manitoba Hydro filed its Cost of Service Methodology Review submission with the Public Utilities Board ("PUB"). The process commenced with a Pre-Hearing Conference which was held by the PUB on February 12, 2016 and resulted in Procedural Order 26/16. Procedural Order 26/16 established the process for the proceeding which included one round of written Information Requests to Manitoba Hydro. On March 18, 2016, the PUB issued a revised hearing timetable.

An extensive process was conducted over a number of months which included a Manitoba Hydro workshop which occurred from May 11-13, 2016, Intervener Evidence filed on June 10, 2016, a facilitated Intervener Workshop occurring from June 21-23, 2016 and a second Pre-Hearing Conference on June 24, 2016. Following the second Pre-Hearing Conference, the PUB issued Procedural Order 84/16 which revised the hearing schedule and included the filing of Rebuttal Evidence by both Manitoba Hydro and Interveners, and required all parties to file written submissions on issues not subject to the oral hearing on August 12, 2016. The concurrent evidence oral hearing occurred from September 7-9, 2016 and consisted of direct presentation and cross-examination of Manitoba Hydro and a concurrent evidence panel of Intervener consultants and Manitoba Hydro's independent consultant, Christensen Associates Energy Consulting ("CA"). Written submissions on issues subject to the oral hearing were received from Interveners on September 21, 2016 and Intervener Reply submissions were received on September 26, 2016.

In concluding this comprehensive 10 month process, Manitoba Hydro is providing its written reply submission on issues subject to the concurrent oral evidence session to the submissions of the Manitoba Industrial Power Users Group ("MIPUG"), The Consumers Association of Canada/Winnipeg Harvest ("Coalition"), the Green Action Centre ("GAC"), the City of Winnipeg ("COW"), the General Service Small and General Service Medium ("GSS/GSM") Classes, and Manitoba Keewatinowi Okimakanak Inc. ("MKO").

3.0 BACKGROUND

In 2011, Manitoba Hydro embarked on a review of its Cost of Service methodology. Manitoba Hydro retained the services of CA to conduct an independent external review. The purpose of the review was to determine whether Manitoba Hydro's costing methodology was consistent with industry best practices, met Manitoba Hydro's specific needs and supported the equitable pricing of utility services. CA provided their findings to Manitoba Hydro in a 2012 report filed as Appendix 5.0 to Manitoba Hydro's December 4, 2015 submission. Many of CA's recommendations have been incorporated into subsequent Cost of Service Studies.

Since the submission of CA's initial 2012 report, a number of changes and developments occurred in the business environment in which Manitoba Hydro operates, including development in the Manitoba and North American electricity markets[1] and approvals for investment in new Generation and Transmission.[2]

In 2014, in advance of filing a Cost of Service Submission to the PUB, Manitoba Hydro embarked on a stakeholder engagement process to disseminate information about Manitoba Hydro's current Cost of Service methodology and to solicit feedback from interested parties. Manitoba Hydro provided two workshop sessions in late 2014 that were attended by Intervener stakeholder representatives and their COS consultants, PUB staff and PUB engineering technical advisor. Through the course of these workshops, Manitoba Hydro was able to obtain comments and perspectives from stakeholders on various COS assumptions and alternative treatments.

As a result of all these developments, Manitoba Hydro committed to have CA provide a supplemental report to address industry and business changes and to consider the input received from stakeholders. In 2015, CA issued a Supplemental Report which was filed as Appendix 2.0 to Manitoba Hydro's December 4, 2015 submission.

3.1. Manitoba Hydro's Cost of Service Treats All Customers in a Fair and Equitable Manner

Some parties have suggested that Manitoba Hydro should be indifferent to cost of service because the Corporation is entitled to collect its full revenue requirement regardless of the methodology used.[3] By inference, certain parties have expressed the view that Manitoba Hydro's advice and perspectives regarding appropriate methodology should hold less weight.

Manitoba Hydro disagrees with these suggestions. Cost of Service methodology indeed can impact revenue requirement through its impact on rates, which impacts consumption decisions of customers and thus, revenue requirement. Manitoba Hydro is committed to a principled and logical cost methodology which treats all of its customer classes in a fair and equitable manner. Other than the PUB itself, Manitoba Hydro is the only party that can treat all customer groups independently; it is therefore critically important that Manitoba Hydro's Cost of Service perspectives are given the weight they deserve.

[1] The wholesale prices of electricity have declined from the high level experienced during the mid-2000 period, however, they still represent approximately 20% of revenue today.
[2] These include Keeyask, BiPole III, Manitoba-Minnesota US Interconnection, and Riel.
[3] See for example Mr. Hacault's comments at the 2015 Cost of Service Review Pre-hearing Conference, Transcript pg. 118-119, and Mr. Orle's comments from MKO's Written Submission, September 21, 2016, pg. 2

3.2. Manitoba Hydro's Cost of Service Study is Sound

Manitoba Hydro's Cost of Service Methodology as reflected in PCOSS14-Amended is sound and can be relied upon for purposes of determining the adequacy of rates. The results of the external review undertaken by CA as well as Interveners to this process, both reach the same conclusion, that overall, Manitoba Hydro's Cost of Service Methodology is sound.

There have also been some suggestions made in final argument that Manitoba Hydro's Cost of Service Methodology is a "work in progress"[4], continues to be in a state of flux[5], is unreliable for rate setting purposes[6], and that numerous further studies are required.

Manitoba Hydro strongly disagrees. As has been shown throughout the course of this process and during the concurrent evidence session, there is considerable agreement with respect to the most significant aspects of Manitoba Hydro's methodology which impact 80%[7] of Manitoba Hydro's revenue requirement.

In particular, these issues broadly relate to the use of the Weighted Energy allocator, the treatment of export class and net export revenues. While some disagreement continues to exist regarding the functionalization of some major assets, whether capacity considerations have been appropriately or sufficiently reflected in COS methodology, and the extent to which Opportunity exports cause fixed costs to be incurred, even Mr. Bowman agrees that, for the most part, Manitoba Hydro's COS methodology is within standard industry practice.[8]

Manitoba Hydro agrees with the conclusion of MIPUG (September 26, page 7), although for different reasons, that the results of this process have provided sufficient evidence for the PUB to provide its views and rationale to conclude on Cost of Service Methodology to the extent possible and that any further study on COS methods should be minimized unless the record proves an absolute need.

4.0 PURPOSE OF COST OF SERVICE

The purpose of Cost of Service is to determine the cost responsibility of the customer classes that Manitoba Hydro serves. The Cost of Service process begins once Manitoba Hydro's overall revenue requirement has been established.

[4] Coalition Written Submission, September 21, 2016, pg. 39
[5] 2015 Cost of Service Review, September 8, 2016, pg. 368
[6] GAC Written Submission, September 21, 2016, pgs. 6-7
[7] Manitoba Hydro Presentation, Slide 3, 2015 Cost of Service Review, September 7, 2016
[8] Pre-filed Evidence of Mr. Patrick Bowman, June 10, 2016, pg. 1

As Mr. Harper describes in his evidence, pages 14-15

> *"The first stage focuses on the determination of the overall revenue requirement that the utility will be allowed in the test (or rate) year or, put another way, the overall rate level. At this stage consideration is given to the reasonableness of the forecast of customer energy and peak load that the utility will be expected to supply along with associated costs, including the return on investors' capital[9] where applicable. When it comes to these costs the focus is on whether the costs are necessary, reasonable and prudently incurred in order to provide the utility's customers with safe and reliable service."*

The purpose of Cost of Service is to allocate Manitoba Hydro's established Revenue Requirement to each domestic customer class

Therefore, Cost of Service assumes that the appropriate Revenue Requirement has already been established and its function is only to allocate that Revenue Requirement to each customer class. MIPUG has suggested in its evidence[10] and even in final argument[11], although by inference only, that it is appropriate to use Net Export revenue as derived through the output of the COS study to somehow modify revenue requirement which is an input into that same study. This approach is circular and unnecessarily complex. Cost of Service is not the vehicle to be used to reset revenue requirement, that is not the purpose of a COSS and thus inappropriate.

5.0 GOALS OF COST OF SERVICE

After wading through all the perspectives and evidence provided in this process, particularly given its complexity and highly specialized nature, it is evident that setting and understanding COS goals are critically important.

It is important in COS to begin with setting and understanding what goals are important overall in ratemaking. There is no universal right answer when it comes to Cost of Service. At the end of the day we need to rely on informed and reasonable judgment. Goals help shape our thinking in order to choose between numerous reasonable COS methodologies. Goals are also critically important to provide an overall COS framework with strength, soundness, stability,

[9] Clarification added by Manitoba Hydro: Or in the case of Manitoba Hydro, the appropriate level of Net Income.
[10] Pre-filed Evidence of Mr. Patrick Bowman, June 10, 2016, pg. 5
[11] MIPUG Written Submission, September 21, 2016, pg. 1-7

cohesiveness, to minimize unintended consequences, and one that reflects how Manitoba Hydro plans and operates its system.

Manitoba Hydro has provided its views on what goals are important in overall ratemaking starting on page 7 of Manitoba Hydro's December 4, 2015 Submission:

Manitoba Hydro's Overall Goals of Ratemaking:

- Recovery of Revenue Requirement
- Fairness and Equity
- Rate Stability and Gradualism
- Efficiency
- Competitiveness of Rates
- Simplicity

There appears to be broad agreement among Interveners that the primary purpose of a cost of service study is to allocate incurred costs to those who cause them to be incurred. However, there are divergent perspectives regarding whether other ratemaking objectives are appropriately considered in COS; and there are also divergent perspectives about how cost causation is defined.

Manitoba Hydro has taken into consideration ratemaking goals when looking at the issue of cost causation.

Consideration must be given not only to the manner in which its hydraulic system is designed, but also the manner in which it is operated.

Manitoba Hydro views that consideration must be given not only to the manner in which its system is designed, but also the manner in which it is operated. Giving weight to both better reflects the cost responsibility of customer classes. As an example, while generation related costs of a hydraulic utility are virtually all fixed, taking too narrow a perspective of cost causation might result in classifying these costs 100% demand-related and ignore why those costs are incurred or how the facilities are used which is largely driven by the necessity of satisfying the energy requirements of customers. The use of a weighted energy allocator reflects well how and why these costs are incurred and additionally, aids in the support of its efficiency goal.

Similarly, Manitoba Hydro views that simply looking at the generation and transmission assets that give rise to export revenue in order to return it to domestic customer classes is too narrow a view of cost causation. This matter is addressed more fully in the sections regarding the Export Class.

Manitoba Hydro notes that Mr. Orle states:

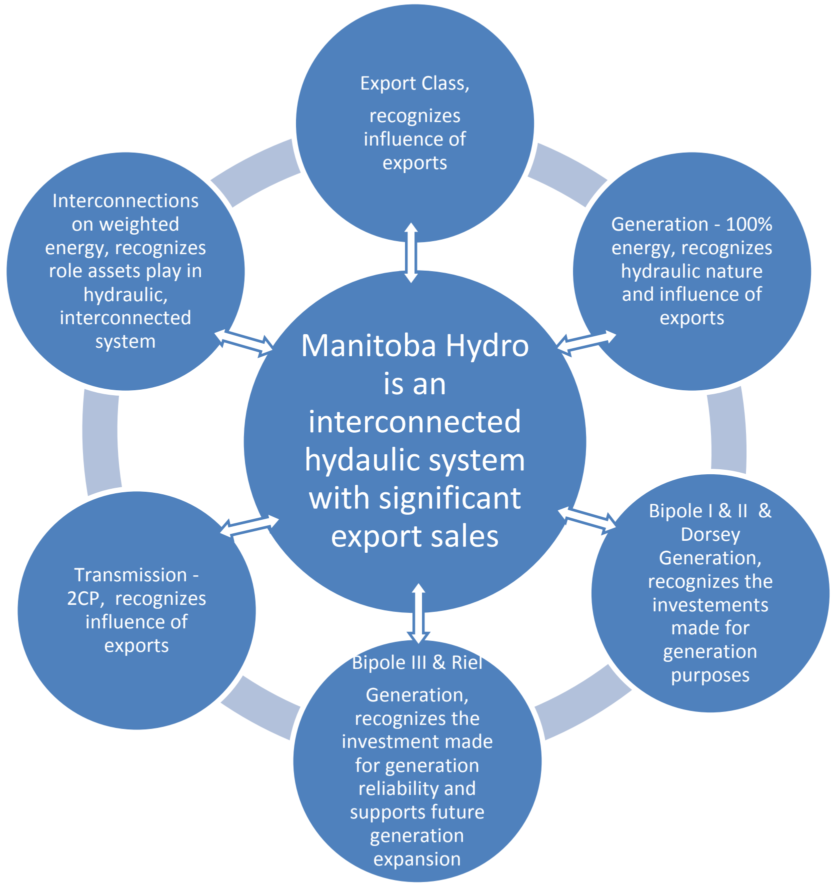
> *"It is our position that the most important guide to the Public Utilities Board and to Manitoba Hydro is set out in the preamble to the Affordable Utility Rate Accountability Act."*[12]

Mr. Orle then goes on to contrast this policy perspective with what he construes as Manitoba Hydro's almost exclusive focus on cost causation. With respect, *The Affordable Utility Rate Accountability Act*, C.C.S.M. c. A6.8 is legislation directed at the Government of Manitoba regarding maintaining a low cost utility bundle of electricity, gas and auto insurance. The legislation is not directed at Manitoba Hydro nor the PUB and it says nothing about what causes Manitoba Hydro to incur costs on behalf of its customers.

5.1. Manitoba Hydro's Framework for Cost of Service is Cohesive

Manitoba Hydro's goals set out in section 5.0 above, along with considerations of both the design and operations of the Manitoba Hydro system, as discussed at transcript pages 22-23, has resulted in Manitoba Hydro's framework for cost of service. This framework, in addition to recognizing the unique characteristics of Manitoba Hydro's system explicitly recognizes the influence of the large interconnected market in which it operates. Manitoba Hydro's methodology has then been developed over time within that framework to provide a well-thought out and cohesive approach to COS. Manitoba Hydro's treatment of its Bipole facilities as Generation, the use of the Weighted Energy allocator, the use of an Export class, and the two coincident peak (2CP) demand allocator for Transmission all reflect this framework:

[12] MKO Written Submission, September 21, 2016, pg 1



As depicted in the above figure, the view of cost causation is important as it recognizes that Manitoba Hydro's revenue requirement, which is based largely on historical cost, reflects not only past planning considerations, but also recognizes that its revenue requirement today and in the future are impacted by the interconnection to an external market as well as both short and long term decisions Manitoban's make to consume contribute sizably also.

It is important to note, that in contrast, Mr. Bowman's evidence and even MIPUG's final argument results in an overall mixing and matching among differing cost of service methodologies. At times he appears to recognize Manitoba Hydro's interconnection as important and influential to COS methodology, at times he attempts to apply traditional concepts more suited to an isolated system.

Furthermore, while openness to other ideas is to be commended, Manitoba Hydro had difficulty following MIPUG's changing views, which in some cases have occurred so late without any support as to how conclusions have been reached. Some examples of MIPUG's internal inconsistency are:

Weighted Energy: MIPUG appears to accept a weighted energy approach which considers the large interconnected market in which Manitoba Hydro operates and recognizes the varying value of energy as an important influence of cost to Manitoba Hydro. At the same time they want to graft on an explicit recognition of demand. Mr. Bowman's evidence and even MIPUG's final argument is suggestive of a 1CP that considers only Manitoba's winter peak and ignoring the characteristics of the neighboring markets. MIPUG's final argument now recommends a 2CP (page 3-2) for the demand component. Without any supporting evidence or argument for this changed perspective, Manitoba Hydro is left without an understanding as to how that recommendation has been arrived at.

Bipoles, Dorsey and Riel MIPUG accepts that Bipole I & II are generation outlet transmission on account of the investment being driven by generation needs. The purpose of investment concept (Mr. Bowman's "economic identity" test) is ignored in Mr. Bowman's continued preference for treating Dorsey Converter station as Transmission notwithstanding that Bipoles I and II, the facilities that it is connected to are treated as generation. Mr. Bowman's evidence is that Riel, on the other hand, should be treated consistent with the Bipole III line that it is connected to.

Similarly, the recognition of Energy as an important driver of cost related to Bipole III, which Mr. Bowman acknowledges in his initial evidence[13] and Transcript (pages 766-769) has been ignored in his preference now for a 2CP allocator[14]. And while the operation of Bipole III will be identical to that of Bipoles I and II, MIPUG's recommendation is to treat Bipole III as Transmission, classified on the basis of 100% Demand and allocated on 2CP, while Bipoles I and II should be treated as Generation, classified on the basis of about 20% 2CP Demand, 80% Weighted Energy.

Export Class: While MIPUG's final argument is silent regarding the use of an export class, one must conclude that they are supportive given the extensive argument about the allocation of cost to opportunity sales and given arguments regarding treatment of NER. MIPUG's preferred option to exclude NER from COS, however, suggests acceptance of a view of cost causation beyond one that only considers returning export revenue on the basis of the generation and transmission (the assets that functionally allow exports to be undertaken). In other words, that cost causation be broadened to consider the cost consequences to Manitoba Hydro's finance expense (debt) as well as Net Income (equity). However, Mr. Bowman's evidence and MIPUG's final argument repeatedly deny it appropriate to return export revenue to domestic customers

[13] Pre-filed Evidence of Mr. Bowman, June 10, 2016, pg. 32
[14] MIPUG Written Submission, September 21, 2016, pg. 4-1

on a basis of anything but generation and transmission costs.[15]. This results in a conflict between MIPUG's views about cost considerations and their ultimate recommended COS treatment.

Manitoba Hydro believes it has established COS methodology based on a cohesive well-founded framework that reflects its overall ratemaking goals and Manitoba's system. Most parties, including Manitoba Hydro's external consultant, CA agree. While it may appear reasonable to look at each individual COS treatment on its own and challenge its appropriateness as Mr. Bowman has done, one must step back at the end to test the overall soundness of what is left, which is missing in Mr. Bowman's proposals overall. As Mr. Harper described during the Intervener Workshops, the pull of the pill of the sweater has unraveled the sweater, and we are left with a pile of yarn[16].

6.0 MANITOBA HYDRO'S APPROACH TO GENERATION-RELATED COSTS IS APPROPRIATE FOR MANITOBA HYDRO'S SYSTEM

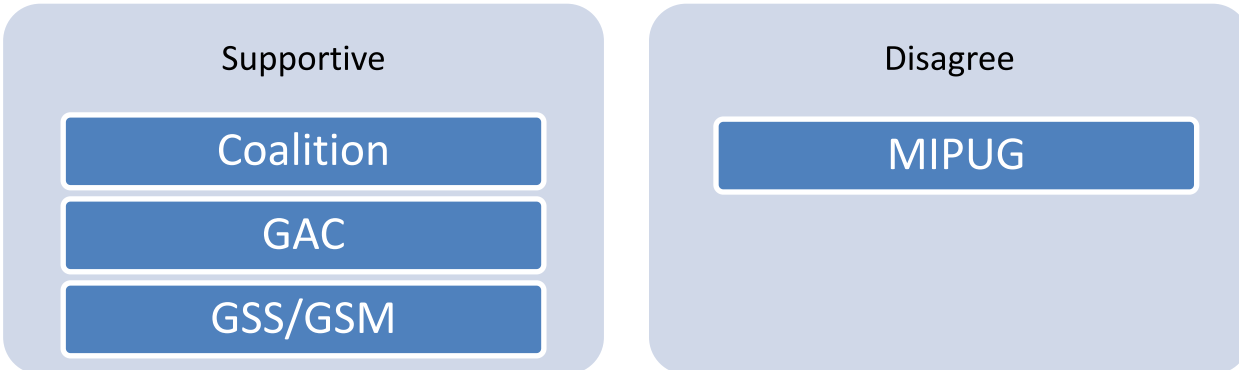
Manitoba Hydro functionalizes 15 hydraulic generating stations, two thermal generating stations, Bipoles I & II, the future Bipole III line, HVDC converter stations and several generation-outlet transmission lines and switching stations as Generation. These facilities currently represent about 65% of Manitoba Hydro's total revenue requirement. It appears that most parties to this process, including CA, are supportive overall of Manitoba Hydro's treatment of these facilities.

Mr. Harper and Chernick have identified a few additional transmission lines they view ought to be included in the Generation function. Mr. Bowman disagrees with Manitoba Hydro's intended approach for Bipole III (and Riel) as well as Manitoba Hydro's updated functionalization of Dorsey Converter Station as Generation-related.

Manitoba Hydro's methodology for generation-related cost is:

Functionalize	• Generation
Classify	• Energy
Allocate	• Weighted Energy

[15] See for example MIPUG Written Submission, September 21, 2016, pg. 1-4, 1-5, and 1-9
[16] 2015 Cost of Service Review Intervener Workshops, June 21, 2016, Transcript pg. 148-149



6.1. Manitoba Hydro’s Use of Generation-outlet Transmission is Appropriate

Manitoba Hydro has included generation-outlet transmission in the Generation function to recognize that the role of these facilities is to bring generation supply to the backbone transmission system.

As discussed by Mr. Harper this is a common industry practice,

> *“It is noted that a similar same approach is used by BC Hydro which in its most recent cost of service proposals approved by the BCUC continues to re-functionalize transmission assets used to connect its remote hydro facilities to the transmission grid as Generation. This approach is also consistent with the industry standards regarding the designation of transmission facilities for purposes of setting Open Access Transmission Tariffs (OATT) and with the fact that incorporation costs (i.e., the costs of transmission facilities required to incorporate new generation into the grid network) are considered when evaluating different Generation options.”*[17]

Manitoba Hydro acknowledges that it does include a larger share of generation-outlet transmission assets as compared to other utilities. This however does not suggest that the methodology therefore must be flawed, as argued by MIPUG:

> *“Hydro overuses what is typically considered a narrow exemption for the purposes of functionalizing transmission lines as generation (the Generation Related Transmission Asset, or GRTA). This practice should be curtailed.”*[18]

Manitoba Hydro’s system is unique in that 70%[19] of its generating capacity is remote and is connected through an HVDC system. A unique system can require a unique cost of service treatment in order to best reflect cost causation.

[17] Pre-filed Evidence of Mr. William Harper, June 10, 2016, pg. 54
[18] MIPUG Written Submission, September 21, 2016, pg. 4-1

In contrast most utilities generating facilities are connected through an AC network with no or little use of an HVDC system. It is of no surprise or consequence that these utilities have less "poles and wires" deemed to be generation-related transmission than Manitoba Hydro. If you exclude the HVDC facilities and look at only AC facilities, which is how Manitoba Hydro's southern generating stations are connected, the proportion of generation-related transmission is approximately 3% of total transmission cost.

6.2. Treatment of Bipole III as Generation Outlet Transmission is Appropriate

Manitoba Hydro is constructing a third Bipole, with a scheduled in-service date of 2018. Manitoba Hydro's treatment of Bipole III will be identical to its treatment of Bipoles I & II:

Functionalize	• Generation
Classify	• Energy
Allocate	• Weighted Energy

Manitoba Hydro's Rationale for Bipole III as Generation:

- Functions identical as Bipoles I&II:
  - Sole purpose to move power from the remote generator to the transmission grid
  - One-directional bullet pipeline
  - Loss of a Bipole means loss of generation
- Not required in the absence of northern generation
- Does not function as grid transmission
  - Can only be used by the generators
  - Supports the AC grid in the same manner as a generator
- Required for <u>generation</u> reliability across many hours of the year

1. The Function of Bipole III is identical to Bipoles I&II

As discussed during Manitoba Hydro's direct presentation on September 7, 2016 (Transcript pages 27-33), the purpose of Bipole III, no different that of Bipoles I and II, is to move power from the northern generators to the meshed AC transmission grid. These Bipoles are integral to generation in order to deliver energy reliability across all time periods. The Bipoles are essentially a one-directional, bullet pipeline whose sole purpose is to move power from the

[19] NFAT, Chapter 5, pg. 253

generators in the north to the load in the south. The Nelson River HVDC System essentially re-locates the Northern Collector System generators (Kettle, Long Spruce, Limestone and eventually Keeyask) from the Lower Nelson to Dorsey and Riel. In essence, it's like having these generators in Rosser and Springfield.

Bipole III represents a widening of that pipeline; it does not change the fundamental nature of that pipeline.

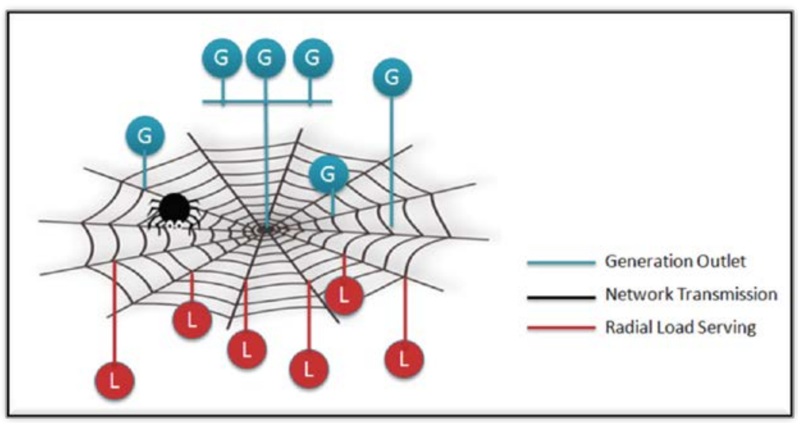
The function of the Bipoles is simply in-separable from the generator; the loss of a Bipole means the loss of the generator. Under normal operating circumstances, the power flow from northern Manitoba will be distributed between Bipoles I, II and III[20].

2. Bipole III is not required in the absence of Northern Generation

The Bipole lines would not be required if it were not for the generating stations having been built in the north, far from the majority of load centers. Currently, northern generation would be stranded if an outage were to occur to Bipoles I & II. This system reliability concern is the motive for the construction of Bipole III. In addition, if Bipole III, were not already being built, some other form of generation-outlet transmission would be required for transporting energy produced at Keeyask.[21]

3. Bipole III does not function as Grid Transmission

As discussed by Ms. Derksen in Manitoba Hydro's September 7th presentation (Transcript pages 27-29), the spider web diagram below shows how generation-outlet transmission lines differ from grid transmission lines. If one link of the spider web is broken, power on the transmission system can instantly be re-distributed (transmission reliability) along the remaining paths or similarly, if a customer's load increases, the transmission spider web can instantly



change the flow on all networked transmission to adapt, because of the integrated nature of its transmission system. Bipole lines are not part of the networked grid and therefore cannot be used to redistribute load. If we lose a branch of the spider web, the load carried by that branch is instantaneously re-distributed among the surrounding branches -- without human

[20] NFAT – Chapter 3, pg. 3-4
[21] September 9, 2016, Transcript pg. 723 and 771

intervention. All branches are instantaneously and simultaneously "used and useful" to all loads. This is in stark contrast to the manual dispatch of generation to balance load -- which is precisely what the operators do when they adjust the DC Power Order.

Conversely if a Bipole line goes down the networked AC grid cannot be used to carry the generation load; only the Northern Collector System generators can put load on the Bipoles. If the Bipole lines go down the generation-outlet link is broken, the generators automatically reduce output, and the system loses access to the generators and the load can no longer be supplied to the other end of the HVDC system.

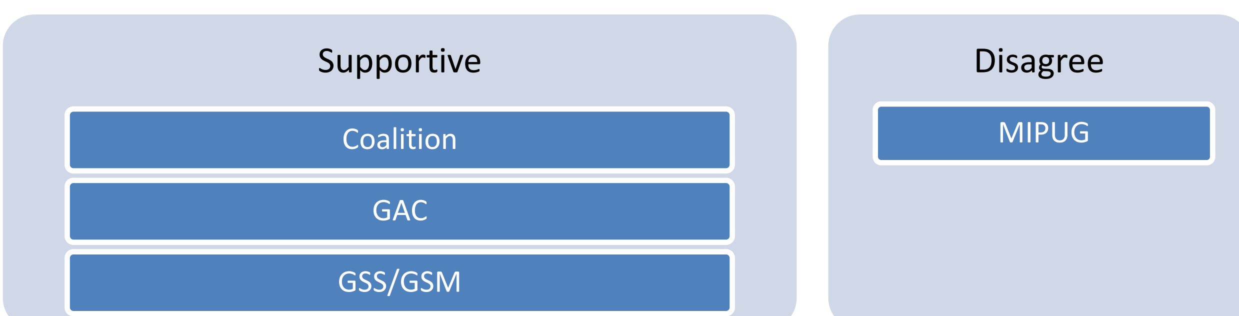
4. Required for Generation reliability across many hours of the year – this is not the same as Transmission reliability

The primary justification of Bipole III (and Riel), was based on system reliability requirements, i.e. to provide contingent transmission capacity to counter the risk of extended outages to the existing Bipoles (and Dorsey). System reliability in this sense relates to Manitoba Hydro's ability to access 70% of its generation capacity 8,760 hours of the year. As demonstrated in rebuttal evidence, demand in Manitoba during the summer of 2015 would have exceeded supply in Manitoba following loss of Bipoles I and II approximately 60% of the time[22]. This far exceeds the 100 hours deemed critical in the allocation of grid transmission.

Furthermore, assuming the risk to the current Bipoles is equally distributed throughout the year, a multi-week outage is likely to occur in a period with little or no representation in the 100 peak hours used in the 2CP Demand allocator.

Intervener Positions

Parties, with the exception of MIPUG, are supportive of Manitoba Hydro's treatment of Bipole III.



[22] Manitoba Hydro Rebuttal Evidence, July 29, 2016, pg. 23

Manitoba Hydro's Rationale for Bipole III

- Functions identical as Bipoles I&II:
  - Moves power from the generator to the transmission grid
  - Bullet pipeline
  - Loss of a Bipole means loss of generation
- Not required in the absence of northern generation
- Does not function as grid transmission
  - Can only be used by the generators
  - Supports the AC grid in the same manner as a generator
- Required for <u>generation</u> reliability across many hours of the year

MIPUG's Rationale

- Not justified as part of new generation
- Too much GRTA
- Bipole III is being built for reliability

Mr. Bowman's evidence is that Bipole III be treated like grid Transmission classified as Demand and allocated using 2CP. Mr. Bowman's arguments can be summarized as follows:

- Bipole III was not part of the business case for new generation
- Other utilities, such as BC Hydro, do not have as much GRTA as Manitoba Hydro
- Bipole III is being built for reliability

Mr. Bowman's criteria of whether Bipole III is part of a business case for new generation misses the fundamental issue that the Bipole III line is not "used and useful" in the absence of generation. Bipole III does not serve any load between the Keewatinohk and Riel converter stations, nor is it possible for it to do so. Without the northern generation, whether built previous or subsequent to Bipole III's justification, Bipole III is not needed; this is in essence the definition of generation-outlet transmission.

Mr. Bowman also attempts to make the case that the construction of Bipole III changes the function of Bipoles I & II, (Transcript page 768):

> *"And in fact, if anything, Bipole III -- the building of Bipole III starts to -- starts to make Bipole I and II look a lot more like part of a transmission network than some generator lead."*

The addition of another Bipole does not make the rest of the Bipoles grid transmission. Power on the Bipole lines is not "used and useful" until it has been converted back to AC, this does not change no matter how many DC lines you add.

Mr. Bowman's argument for the treatment of Bipole III appears also to rest on his very loose definition of reliability (Transcript page 446): *"is a classic component of -- of investing in transmission assets"*

However, interestingly, both Mr. Bowman's evidence and MIPUG's final argument never refers to Bipole III as being built for "Transmission Reliability". And when questioned at the June 21st workshop (Transcript pages 255-256) whether his view is that Bipole III provided Transmission reliability he stated:

> "*I've used the words reliability and I've used the word transmission. When you put them together they start to mean something a bit different* "

This is precisely the point. His treatment implies that he views Bipole III to function like a link in the spider web, rather than a bullet pipeline. This is simply not the case. The evidence is that, Bipole III is not being constructed to provide Transmission reliability (that is another link in the spider web), but rather to provide generation reliability by adding redundancy for the other generation-outlet lines.

Mr. Bowman's recommendation also appears curious in light of his earlier evidence that energy is an important characteristic for Bipole III (Transcript, page 769 and Bowman evidence, page 32),

> *"Energy requirements in -- in all periods are -- are relevant in -- in winter shoulder, winter peak, if that's what we were disc -- what I think we set off discussing first. Energy usage, customer usage in those periods are relevant."*

However, he subsequently goes on to completely dismiss it in favor of a 2CP allocator that fails to recognize the number of hours for which Bipole III is critical.

As discussed in Section 5.0 above, cost causation is properly determined by the use intended for, and made of, the asset, not simply the physical form of the asset. In the selection of COS methodology, consideration must go beyond what the asset is, in this case a pole and wire, and in Manitoba Hydro's view must also look at why the costs are incurred and how the facilities operate.

Bipoles I and II have long been accepted as being generation outlet transmission and treated identically to the generators they connect. This is because the Bipoles' function is simply inseparable from the generators. The timing of construction is irrelevant. To treat Bipole III differently, when its role is identical to Bipoles I & II, is not at all logical. MIPUG's conclusions with regards to Bipole III are simply not congruent with the role Bipole III plays in Manitoba Hydro's system.

In view of all the evidence Manitoba Hydro has provided on the role and purpose of Bipole III, it is somewhat perplexed that MIPUG continues to assert, in its September 26th Reply Submission, that "the evidence is conclusive". "It is not new generation". "It is load growth, particularly at peak times that drives the need for Bipole III"[23] .

Of course load growth drives the need for Bipole III, it drives the need for all utility assets. In the case of Bipole III, load growth is driving the need for generation that operates around the clock and meets both peak and energy requirements.

6.3. Dorsey and Riel Converter Stations are Appropriately Functionalized as Generation

As part of CA's 2012 Report, Manitoba Hydro committed to reviewing its COS approach for Dorsey converter station which at that time was functionalized as 100% Transmission.

Flowing from that review, and as noted in Manitoba Hydro's Response to CA's 2012 Report, Manitoba Hydro concluded that the more cost causative approach for the Dorsey and Riel Converter Stations is to recognize their role in Manitoba Hydro's system, which is to provide energy from the northern generators to the southern load. This is consistent with CA's recommendation in the 2015 Supplemental Report to functionalize Dorsey and Riel Converter Stations to Generation not less than 75%. As part of PCOSS14-Amended, Manitoba Hydro reflected this change summarized as follows:

Functionalize	• Generation
Classify	• Energy
Allocate	• Weighted Energy

[23] September 26, 2016 Reply Submission MIPUG, page 11

Manitoba Hydro's Rationale for Dorsey/Riel as Generation:

- Converter Facilities are dedicated to Bipoles
  - Required for interconnection of Generation
  - Makes northern generation available to the southern grid
- Supports the AC grid in the same manner as a generator
- Bipole III and Riel Converter fulfill the same role as Bipoles I & II and Dorsey

1. Dorsey makes northern generation available to the southern grid

At the advice of CA, Manitoba Hydro has examined its cost allocation approach and has concluded that the primary role of the DC facilities is generation outlet. The inverters are analogous to step-up transformers, which are included in the Generation function, in that they are needed to transform the voltage to a useable level for the networked Transmission system. Until AC conversion is complete at Dorsey the power is not useable for load[24].

2. Dorsey supports the AC grid in the same manner as a generator

The basis of the former functionalization as Transmission was premised on the fact that once in-service, the HVDC technology improved the AC transmission network stability and offered savings on transmission expansion to the US, due to the flexibility in control associated with the HVDC system. The additional support that HVDC provides to the interconnections (high stable firm export limits) is provided in the same manner as "generator unit tripping". In the event that Manitoba Hydro lost a tie-line, the HVDC System (not just Dorsey – the whole system) ramps-down the power injected into the grid such that the export power transferred to the remaining tie-lines is within margins so as to not overload the remaining lines. To make this scheme work, the reduced export power must be instantly made-up by spinning reserve in the MISO pool so as to continue serving load. Clearly, this is a generation solution to increasing tie-line exports. In other words, the nature of the support that Dorsey provides to the AC System is in every sense that of generation.[25]

To be clear, it is not Dorsey's treatment in the PCOSS that is driving the determination of its treatment in the Open Access Transmission Tariff. For the reasons discussed above, future tariffs will exclude the costs of Dorsey and Riel. As noted in Manitoba Hydro's presentation, the inclusion of Dorsey in the most recent tariff occurred only because of timing.

[24] Manitoba Hydro Response to CA Supplemental Report, December 4, 2015, pg. 5-6
[25] Manitoba Hydro Response to Christensen Associates, July 19, 2012, pg. 9

3. Riel and Bipole III fulfill the same role as Dorsey and Bipole I & II

The upcoming Riel Converter station will function for Bipole III exactly like Dorsey does for Bipoles 1 and 2, and Manitoba Hydro views it most appropriate that the COS treatment be identical.

Intervener Positions

All Interveners, with the exception of MIPUG, are supportive of Manitoba Hydro's treatment of Dorsey.

Supportive
- Coalition
- GAC
- GSS/GSM

Disagree
- MIPUG

Manitoba Hydro's Rationale for Treatment of Dorsey

- Converter Facilities are dedicated to Bipoles
  - Required for interconnection of Generation
  - Makes northern generation available to the southern grid
- Supports the AC grid in the same manner as a generator
- Bipole III and Riel Converter fulfill the same role as Bipoles I & II and Dorsey

MIPUG's Rationale for Treatment of Dorsey

- Previous precedence
- Too much GRTA

MIPUG proposes continuing to functionalize Dorsey as Transmission, since this treatment has been accepted in past COSS and OATT calculations, and also recognizes the substantial benefits the station provides to the transmission system.[26]

As described above, the manner in which Dorsey supports the AC system is in the same manner as a generator and it takes the entire HVDC system (Dorsey, Bipole I & II, Henday, Radisson, and the northern generators - Limestone, Kettle and Long Spruce) to affect this support. To

[26] Manitoba Hydro Presentation, Slide 24, 2015 Cost of Service Review, September 8 2016

continue to isolate Dorsey for separate treatment from the rest of the HVDC system for which it was built does not make sense. MIPUG's proposal also results in an illogical outcome of treating Bipoles I and II as Generation and Dorsey as Transmission while Bipole III and Riel both Transmission.

MIPUG notes,

> *"absent the favourable characteristics of the Dorsey DC technology, Manitoba Hydro would have to invest in far more expensive alternative equipment (that would be inherently transmission assets for rate and OATT purposes)."*[27]

Manitoba Hydro agrees with the statement, however as mentioned in their reply to the Supplemental Christensen Report, a cost allocation approach that considers the primary role of the investment is the superior cost causal approach[28] – if a generator allows you to avoid a transmission cost it is still a generator.

Manitoba Hydro does not agree that methodology must be bound by past practice, and asserts that there is compelling evidence that the Dorsey Converter Station is generation-outlet transmission and the support that Dorsey provides to the AC system cannot be achieved in isolation from the entire HVDC system. The treatment in the COS should reflect the primary role of the facility.

6.4. Additional Generation Outlet Transmission

In PCOSS14-Amended the only AC transmission assets that are functionalized as Generation are the Northern Collector circuits between the Lower Nelson generators and the Radisson/Henday convertor stations.

In the study, the Non Tariffable Transmission function also includes a number of lines that are solely required to connect generating facilities to the networked transmission grid. In the absence of generation, these lines would be carrying zero power, and therefore should be appropriately functionalized as Generation.

Intervener Positions

As part of this process, parties identified and generally agree that there are transmission facilities that are more appropriately included in the Generation function. Mr. Harper recommends that lines linking generation to the transmission system should be included in the

[27] MIPUG Written Submission, September 21, 2016, pg. 6-4
[28] Manitoba Hydro Reply to the Supplemental Christensen Associates Report, pg. 6

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

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

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

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

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

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

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

> *element in the grid is used and useful to all -- is used and useful simultaneously to all transmission customers."*

6.5. Weighted Energy Allocator is Well Reasoned and Recognizes Manitoba Hydro's Dominant Hydraulic Utility

Manitoba Hydro notionally classifies all generation costs as energy related, with costs allocated to classes on the basis of energy consumption weighted by the relative market value of energy in each of twelve time periods. Manitoba Hydro adopted this allocation methodology in the mid-2000's.

Manitoba Hydro's Rationale for the Weighted Energy Allocator:

- Allocator recognizes Demand implicitly
- Recognizes unique characteristics of a Hydraulic utility
- Captures the time-varying economic value of resources
- Incorporates both equity and efficiency ratemaking goals

1. An Implicit Recognition of Demand is Reasonable

Fundamentally, it is not possible to precisely discern the extent to which marginal energy prices may reflect reliability or scarcity (i.e. capacity considerations). The MISO market, which determines Manitoba Hydro's marginal energy cost in most hours of a typical year was only unbundled into capacity and energy components recently and there is some question remaining as to the extent to which the MISO capacity market captures the relevant value of capacity[31].

What can be stated with certainty is that the Weighted Energy allocator is not the same thing as the energy allocator as typically found in industry, which is an un-weighted energy allocator. In Manitoba Hydro's rebuttal evidence filed in the 2006 Cost of Service proceeding (page 39-40), it was shown that the on-peak premium was equivalent to 27% of the total weighting and that the use of the weighted energy allocator yielded RCC results which were very close to the results that would have been obtained with a Demand classification of 18% allocated on 2CP with the Energy portion allocated on un-weighted energy. While this peak period price premium is not a pure capacity cost, at least as capacity cost is generally understood, it does give more weight and cost to customer class demands in peak periods and is shown to substitute to some extent for an explicit Demand/Energy classification.

[31] Christensen Associates Supplemental COS Report, pages 18-20.

Today, the calculation of the extent to which the Weighted Energy allocator incorporates capacity considerations is complicated by the addition of eight more periods such that the weighting is now based on four seasons each with Peak, Shoulder and Off-Peak periods, and the fact that the number of hours varies significantly from period to period. CA's response to Undertaking #2, filed with the PUB on September 19, 2016, demonstrates that the premium (prior to application of the capacity adder) in the 2,014 hours of Peak periods relative to the combined Shoulder and Off Peak periods would account for approximately 11% of total Generation cost based on 100% load factor; therefore somewhat more than 11% if one were to examine the actual energy profile of the loads included in the cost of service study.

2. Weighted Energy recognizes unique characteristics of a predominantly hydraulic based generation utility

Use of a Weighted Energy allocator for Generation appropriately recognizes the energy limited nature of a predominantly hydraulic-based generation system where hydraulic facilities are planned and developed to meet energy needs ata low variable costs. The allocator also reflects how Manitoba Hydro plans and operates its largely hydraulic resources to take advantage of different prices at different times.

3. Weighted Energy captures the time-varying economic value of resources achievable by Manitoba Hydro

Recognizing the value of energy during different seasons and times of the day is important because decisions customers make on when to consume impacts costs incurred by Manitoba Hydro (thus, revenue requirement) at the margin either through reduced market sales or increased use of imports or internal resources (thermal and hydro).

The allocation approach segregates each class' energy consumption into twelve time periods each assigned a weighting on the basis of the marginal value of energy in that period. MH uses average Surplus Energy Program (SEP) prices as a proxy for the marginal value of energy. Most of the time SEP prices are similar to hourly energy prices at the MISO interface but when either flow conditions and/or transmission constraints are such as to make that price not achievable by Manitoba Hydro, SEP prices can equate to market prices in other periods, or the internal variable cost of thermal generation or hydro generation.

As discussed by Ms. Derksen in the Concurrent Oral Evidence Hearing[32] the PCOSS does not use weekly forecast SEP prices established and approved by the PUB each week. Instead, the PCOSS uses the after the fact actual SEP prices. Actual SEP prices that are used in Cost of Service are

[32] 2015 Cost of Service Review, September 7, 2016, Transcript pg. 37:14 – 38:10

identical to those in MISO in all situations where MISO prices represent the real short-term marginal value of energy to Manitoba Hydro. However, it should be noted that during periods of high water conditions, drought, or generation/transmission constraints, SEP prices, on an actual basis, may be higher or lower than those observed in MISO because the actual resource on the margin is internal generation or imports.

4. Weighted energy incorporates both equity and efficiency ratemaking goals within the context of embedded cost of service

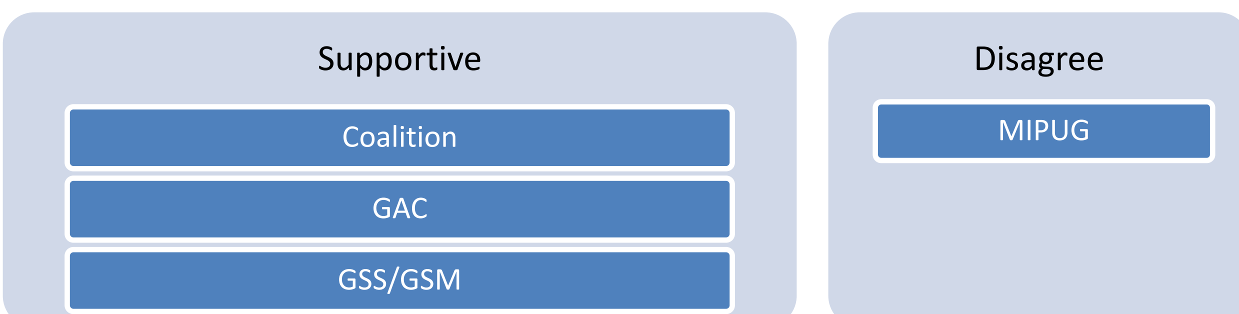
The use of a Weighted Energy allocator assigns greater cost responsibility to those who use more costly energy at peak periods, which is a measure of fairness. As noted by CA:

> *"MH's cost allocation appropriately integrates marginal cost into generation cost allocation, thus recognizing the cost allocation objective of resource efficiency within the process of fully distributed costing."*[33]

Intervener Positions

Interveners, with the exception of MIPUG, have been supportive of the use of Weighted Energy to classify and allocate Generation Mr. Harper notes:

> *"As a result, continued use of Manitoba Hydro's approach of classifying Generation costs as notionally energy related and allocating them to customer classes on a weighted energy basis is reasonable and a preferred approach given the alternatives available."*[34]



[33] Christensen Associates, Review of Cost of Service Methods of Manitoba Hydro, June 8, 2012, pg. 12
[34] Pre-filed Evidence of Mr. William Harper, June 10, 2016, pg. 59

Manitoba Hydro's Rationale for the Weighted Energy Allocator	MIPUG's Rationale
• Allocator recognizes Demand implicitly • Recognizes unique characteristics of a Hydraulic utility • Incorporates both equity and efficiency ratemaking goals • Captures the time-varying economic value of resources	• Need to explicitly recognize Demand at classification stage

MIPUG supports Manitoba Hydro's use of the Weighted Energy allocator, but recommends that Generation-related costs be first classified into Demand-related and Energy-related components and the Weighted Energy allocator then be applied to the Energy portion. With respect to the treatment of the demand-related component, Mr. Bowman's evidence and even MIPUG's final argument is suggestive of a 1CP that considers only Manitoba's winter peak. However, MIPUG's final recommendation is a 2CP[35] for the demand component is without any supporting evidence or argument for this changed perspective. Manitoba Hydro is left without an understanding as to the basis of MIPUG's new recommendation.

Mr. Bowman disputes that the Weighted Energy allocator incorporates any consideration of capacity noting that:

> *"This weighted energy approach is appropriate as a means to allocate all generation costs which are classified to energy"* [36]. However, he then goes on to say: *"the largest issue with Hydro's proposed generation classification and allocation approach is the failure to classify most generation to capacity."*

MIPUG's recommendation in their Written Submission is to classify between 21 and 23%[37] of Generation cost as Demand-related based on versions respectively, of the System Load Factor method used by Manitoba Hydro prior to 2006 and the Equivalent Peaker method.

MIPUG recommends that Manitoba Hydro be directed to undertake a review of alternate methods used by comparable utilities.[38] The record of this proceeding already includes two

[35] MIPUG Written Submission, September 21, 2016, pg. 3-2
[36] Pre-filed Evidence of Mr. Bowman, June 10, 2016, pg. 20
[37] MIPUG Written Submission, September 21, 2016, pg. 3-1

such reviews. The 2004 NERA Report[39] included a review of the methods used at ten utilities with similar characteristics to Manitoba Hydro; while the Leidos survey[40] prepared for BC Hydro provides a more recent jurisdictional review of utility generation methodologies. Manitoba Hydro submits there is nothing to be gained by directing the utility to undertake another review of methods used at comparable utilities.

Manitoba Hydro notes MIPUG's contention that all other utilities in the Leidos survey pre-classify some portion of Generation to Demand[41]. However, Manitoba Hydro notes that this contention applies only to plant in service. For two utilities, Bonneville Power and Seattle City Light, classification of plant in service cost is shown to be "not applicable". For other supply related cost, including O&M and Purchased Power, these utilities use a 100% energy classification; Bonneville allocates the cost either by direct assignment or on the basis of annual energy at Generation and Seattle City allocates on a weighted energy basis. Of the seven jurisdictions that employ a Demand classification, the majority allocate the Energy portion on an un-weighted energy basis.

6.5.1. SEP Prices are an Appropriate Measure for Marginal Cost

Mr. Chernick has questioned the appropriateness of using SEP prices as a reflection of short run marginal energy cost because of an apparent divergence between period weights based on SEP prices and period weights based on actual MISO prices during the period of January 2009 to March 2012.[42] The data included in Mr. Chernick's analysis reflects the mainly high water conditions during 2009-2012 when, during a significant number of Off Peak hours, the marginal resource was system spill whose costs are only water rentals and some operating and maintenance costs. This drives down the Off Peak SEP price or conversely drives up the Peak and Shoulder ratios relative to ratios based strictly on MISO prices.

On this basis Manitoba Hydro asserts that SEP remains the best measure of short run marginal cost available and, contrary to GAC's recommendation[43] there is no need to re-examine reliance on this data. In fact as directed in the original PUB Order which approved the creation the Surplus Energy Program, Manitoba Hydro already files annual reports[44] on the status of the program. This report includes a comparison of weekly average prices approved by the PUB with

[38] MIPUG Written Submission, September 21, 2016, pg. 3-1
[39] PUB MFR-1, 2015 Cost of Service Review, pgs. 21-23
[40] Coalition Exhibit 22-1, 2015 Cost of Service Review, pgs. C1-C9
[41] MIPUG Written Submission, September 21, 2016, pg. 3-3
[42] Pre-filed Evidence of Mr. Paul Chernick, June 10, 2016, pg. 29-30
[43] GAC Written Submission, September 21, 2016, pg. 14
[44] See for example Appendix 6.8, 2015 Electric GRA

the actual after-the-fact prices that are used in the PCOSS. It also indicates the sources of supply on the margin, that is, displaced exports, spill and so on.

Peak period weights have increased between PCOSS06 and PCOSS14-Amended. This has been cited by Coalition as a reason not to adopt a capacity adder for Peak periods.[45] Manitoba Hydro would like to point out that the same factor which has driven divergence of SEP prices from MISO prices as discussed above has also resulted in Peak period weights increasing in PCOSS14-Amended. That is, Off Peak prices reflect considerable spill and consequently low marginal cost in the latter years included in the PCOSS14-Amended weightings. Therefore higher Peak to Off Peak ratios in PCOSS14-Amended do not, in of themselves, suggest a capacity adder is not required.

6.5.2. Capacity Adder Refinement

The higher value of energy in Peak periods reflects increased variable operating costs during this higher demand period, and can include, to varying degrees, a scarcity rent which can approximate some portion of the annual carrying charges on capacity. This substitutes for explicit consideration of capacity related costs in the weighting. Through the process of their review, CA has stated that this premium, scarcity rent inherent in energy prices, is both highly volatile and insufficient as a result of current market conditions and does not adequately capture the value of generation capacity.

CA noted that the recent introduction of voluntary capacity markets within MISO suggests that the implicit Demand recognition in the Weighted Energy approach may not be sufficient to capture full, long-term marginal generation. Low prices in the initial auctions suggest that the amount of scarcity rent that has actually been included in recent on-peak prices has been minimal, while in the long-term the presence of a capacity market could be argued to eliminate any scarcity rents[46]. PCOSS14-Amended incorporated a Capacity Adder into the Weighted Energy allocator to address these issues.

Manitoba Hydro's Rationale for Capacity Adder:

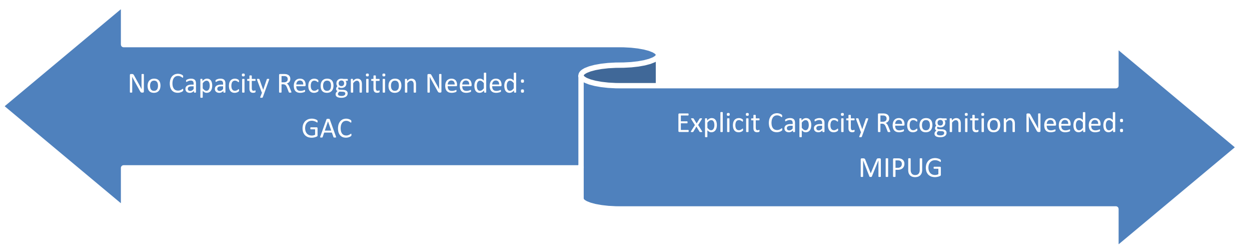
- Introduction of capacity markets
- Insufficient scarcity content in on-peak price

[45] Coalition Written Submission, September 21, 2016, pg. 28
[46] Christensen Associates Supplemental COS Report, pages 18-21.

To incorporate capacity considerations, Manitoba Hydro has utilized the same value as the PUB approved discount per kW for curtailable service to large industrial customers. This value, $38 per kW/year, is distributed into all Peak hours of the year (2,014 hours) resulting in a 1.89 cents per kWh adder to the marginal energy cost. This value is not as high as the all-in cost of a peaker, but is at the high end of the range of recent prices in the voluntary capacity market in MISO. It also has the advantage of being relatively stable from year to year. As a consequence of the capacity adder, the weights given to the Peak periods are increased in the order of 30%, for example, the winter Peak weight is increased from 4.8 to 6.1 relative to the summer Off Peak period[47].

Intervener Positions

Interveners appear to be unsupportive of Manitoba Hydro's application of the capacity adder, although not all share the same reason for disagreement. Broadly, interveners have three different reasons for not supporting this approach.



At one end of the spectrum, Mr. Chernick, on behalf of GAC, does not believe that capacity drives costs for generation at all for Manitoba Hydro. On page 27 of his Pre-filed Evidence he states: *"those costs are not driven by capacity requirements"*.

During the process, in response a question by to Ms. Fernandes he states:

> *"The context we're talking about here is peaking capacity, ability to meet your peak demand, a demand-driven capacity. And, in that sense, the costs of – the fixed costs of Manitoba Hydro's system are not being driven by capacity requirements"*[48]

And finally, when asked by PUB Counsel Mr. Peters as to what percentage of Manitoba Hydro's generation cost classified to capacity would not be too much he replied[49]: "*Zero*"

[47] Manitoba Hydro Rebuttal Evidence, page 19
[48] Transcript page 773
[49] Transcript page 778

At the other extreme of intervener perspective on the capacity adder is MIPUG. In MIPUG's Written Submission on Issues Subject to Oral Hearing and Concurrent Evidence dated September 21, 2016, they state:

> *"the appropriate (and very simple) solution to this problem is to incorporate an explicit capacity classification for generation"*[50].

As noted above, MIPUG would prefer to see an initial classification in the order of 21-23% applied to Generation costs. In the alternative, if a capacity adder is to be used, they do not explicitly take issue with the magnitude of the adder, but rather with the fact that it has been spread over too many hours. For example, Mr. Bowman's Rebuttal Evidence on this matter is entirely taken up with the question of the number of hours over which the adder has been spread in PCOSS14-Amended.

The third group of interveners not supporting the capacity adder is less dogmatic. They do not assert that capacity has no role in driving generation cost; only that it is premature to incorporate a capacity adder or that it may lead to some degree of double counting capacity when taken in conjunction with the energy period weights. Mr. Harper noted that it is premature to introduce a capacity adder and that further consideration is required in terms of the need for one, its value, and the hours over which it should be distributed.[51] In answer to Mr. Peters' question about using weighted energy with no capacity adder he stated:

> *"I don't view it as 100 percent energy. It's 100 percent weighted energy where -- where the weights take into account both capacity and energy considerations."* (Transcript, pages 786 – 787).

The Coalition has taken the position that the evidence does not support that there is a need to include a capacity adder.[52]

GSS/GSM simply *"suggests that the use of the capacity adder requires further study."*[53] However, they also mischaracterize the evidence of Ms. Derksen as being supportive of their position whereas Ms. Derksen was merely acknowledging that this was the position of GSS/GSM. Ms. Derksen then went on to indicate that Manitoba Hydro is prepared to re-examine the application of the adder. In the context of Manitoba Hydro's overall body of

[50] MIPUG Written Submission, September 21, 2016, pages 3-19
[51] Pre-filed Evidence of Mr. William Harper, June 10, 2016, page 64
[52] Coalition Written Submission, September 21, 2016, page 30
[53] GSS/GSM Written Submission, September 21, 2016, page 4

evidence during this proceeding, however, this willingness to re-examine can only be construed to mean that Manitoba Hydro has offered to review the details of its application (e.g. Number of hours into which the adder is distributed) not the overall need to incorporate an adder in some form at the current time[54].

1. Capacity plays an important role in Manitoba Hydro's generation planning

Manitoba Hydro disagrees with Mr. Chernick's assertion that capacity plays no role in driving generation costs. Mr. Chernick makes this assertion on the basis that energy constraints drive new plant additions years prior to when capacity constraints would be encountered and that, by building for energy, capacity is automatically assured and therefore has no cost. See for example his Rebuttal on pages 8 and 9.

This argument completely ignores the need to design hydro-electric plants to be able to meet load in all hours of the year. If they were designed to meet firm energy requirements only, this could be satisfied with fewer turbines. This is clearly illustrated in MIPUG Exhibit 24 where the costs and energy output of two versions of Conawapa are compared. Both a five unit and a 10 unit Conawapa provide similar amounts of dependable energy, but as Mr. Cormie points out (Transcript page 257), the 10-unit configuration has a 25% higher capital cost, but also has 50% greater generation capacity – which provides the very important ability to meet peak demands and adapt to Manitoba load shape.

2. Explicit recognition of capacity at the classification stage is not needed

Similarly, Manitoba Hydro disagrees with Mr. Bowman's assertions that its allocator gives inadequate weight to capacity. As discussed above, even prior to applying the capacity adder, the Weighted Energy allocator, with strong weights attached to the Peak periods, can give results similar to an allocation methodology with 18% explicit capacity component. The addition of the capacity adder, as demonstrated in the Undertaking #2 prepared by CA increases the implicit capacity component to 17%. As Manitoba Hydro demonstrated in its response to MIPUG/MH-I-10(a) its proposed methodology in PCOSS14-Amended yields results which are very similar to the results obtained with a 20% classification to Demand, with Demand-related costs allocated on 2 CP and Energy-related costs allocated on un-weighted energy.

In conclusion, Manitoba Hydro's current approach for classifying and allocating Generation related costs provides adequate weight to costs incurred for making capacity available.

[54] September 7, 2016 Transcript pages 184-186

3. Use of capacity values from the CRP Program is appropriate

Some interveners have suggested that because the capacity prices in MISO have been very low in recent years that the CRP value is excessive for use as a capacity adder. This perspective can be found in the Pre-Filed Evidence of Mr. Chernick (pages 28-29), the presentation of Mr. Goulding[55], as well as the Closing Submission of the Coalition (page 30). However, as Mr. Robert Camfield from CA has advised,

> *"What we can say is that the MISO option for capacity these days is a work in progress. And you cannot, in my view, rely upon the option (sic) prices that come out of the MISO option (sic) as a basis to determine what the capacity happens to be."*[56]

Mr. Camfield's perspective on the state of the MISO capacity market is supported by evidence provided during the NFAT proceeding. In its role as an independent expert consultant, Potomac Economics stated,

> *"It is important to recognize that the MISO does not currently have a well-functioning capacity market that would establish prices consistent with this net revenue methodology."*[57]

Manitoba Hydro continues to believe that the CRP provides a stable basis for incorporating capacity considerations into the Weighted Energy allocator. In absence of an efficient capacity market, external prices cannot be relied upon to conclude that the CRP values are excessive.

6.5.3. Incorporation of Capacity Adder to time periods

There remains a question as to whether or not the capacity adder is spread into the appropriate number of hours. In PCOSS14-Amended, the adder is spread equally into all the Peak hours of the year. The peak hours are defined as the eight high load weekday hours (excluding statutory holidays) which total 2,014 hours or 23% of all hours in a year. For purposes of comparison, as Ms. Derksen noted the traditional 5 day by 16 hour (5x16) peak period definition from MISO results in approximately 4,000 peak hours and the 7x4 period for Use Limited Resources such as hydroelectric generation would result in approximately 1,500 peak hours[58].

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[55] 2015 Cost of Service Review, September 8, 2016 Transcript, pgs 400-401
[56] 2015 Cost of Service Review, September 8, 2016 Transcript, pg. 307
[57] http://www.pub.gov.mb.ca/nfat/pdf/miso_potomac_redacted_mar_25_2014.pdf, pg. 9
[58] 2015 Cost of Service Review, September 7, 2016 Transcript, pgs. 40 – 41

Intervener Positions

Manitoba Hydro's Rationale for Peak Hours Used	**MIPUG's Rationale**
• Consistent with Peak hours used in Weighted Energy allocator • Similar to number of hours for Use Limited Resources	• Too many hours

Mr. Bowman's Rebuttal Evidence raises concern that this is too wide a range of hours.[59] His Rebuttal Evidence notes correctly that there is a difference in capacity use and share of capacity costs borne by the various classes if the definition is narrowed to a 2CP (top 50 hours in each of summer and winter).

Mr. Hacault and Mr. Camfield had an extended discussion on considerations driving the number of hours that are appropriately included in the peak period for capacity cost allocation[60]. During this discussion Mr. Camfield made the point that not only high loads, but also available system resources, could affect which hours are the critical hours in which capacity resources are most constrained.

In summary, the record is not conclusive on the question of the appropriate number of hours to include for allocating capacity related cost. As a first approximation, Manitoba Hydro believes its application to be reasonable. However, Manitoba Hydro had indicated during the Hearing[61] that it was prepared to further examine the number of hours used. MIPUG's final argument suggests that, as an alternative to an explicit classification of some Generation costs to Demand, the PUB could consider applying the capacity adder to only the summer and winter periods.[62] Manitoba Hydro is prepared to consider this suggestion as an interim approach pending further examination of the appropriate number of hours into which the capacity adder should be applied.

7.0 MANITOBA HYDRO'S TREATMENT OF TRANSMISSION ASSETS IS APPROPRIATE

Once generation-related transmission is determined there is very little controversy with regards to the functionalization of >100 kV transmission assets. Manitoba Hydro classifies grid transmission as Demand and allocates it using 2CP. No parties have advanced a differing position to that of Manitoba Hydro with the exception of the US Interconnections.

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[59] Rebuttal Evidence of Mr. Patrick Bowman, August 5, 2016, pg. 8
[60] 2015 Cost of Service Review, September 9, 2016 Transcript, pgs. 734-738 and 745-747.
[61] 2015 Cost of Service Review, September 7, 2016 Transcript pgs.40-41
[62] MIPUG Written Submission, September 21, 2016, pg. 3-20

7.1. Weighted Energy is an Appropriate Allocator for the US Interconnections

As part of their 2015 Supplemental Report, CA recommended that the treatment of the US Interconnections be modified to better reflect the role these assets serve in Manitoba Hydro's system. As discussed during CA's Supplemental Report at pages 15 & 16, the role of US Interconnections is primarily related to moving energy, by way of export and import transactions. While these interconnections may be used during peak hours, it is really the transfer of energy over longer periods that provides the greatest benefit to Manitoba Hydro and drives the investment in these facilities. Manitoba Hydro accepted the recommendation and supporting rationale. Manitoba Hydro noted that CA, along with NERA Consulting in 2004, recommended the same treatment[63]. As part of PCOSS14-Amended, Manitoba Hydro reflected this change summarized as follows:

Functionalize	• Transmission
Classify	• Energy
Allocate	• Weighted Energy

Manitoba Hydro's Rationale for Using Weighted Energy for US Interconnections

- Provide access to US generation resources which is source of generation reliability
- Provide an outlet for surplus Manitoba generation
- Facilitate economic exchanges of energy
- Allow for sharing of capacity resources
- Allow for sharing of generation contingency reserves

The benefits and role of the US Interconnections, which ultimately lead Manitoba Hydro to its Energy classification, were discussed extensively during the NFAT process. [64]

[63] PUB MFR, Tab 1, 2015 Cost of Service Review, pg. 39
[64] NFAT Chapter 5

1. US Interconnections provide access to US generation resources which is a source of generation reliability

While both interconnections and networked grid transmission are comprised of a series of poles and wires, the assets serve very different functions in Manitoba Hydro's system. Similarly, the reliability provided by the US interconnection is different than that of a regular network line or a regular strand of the spider web. The US interconnection provides Manitoba with access to generation resources and therefore provides generation reliability in times of drought or system emergency which can occur over prolonged periods. This is in contrast to transmission reliability which is concerned with ensuring the transmission system is capable of meeting peak demands.

2. Provide an outlet for Manitoba generation surplus to domestic need

The nature of a predominantly hydraulic generation resource is that there is usually significant energy in excess of the needs of Manitoba (above dependable water conditions produces surplus energy in any given year). In addition, the size of the large hydro generating stations results in large surpluses (to Manitoba needs) of dependable energy when the plants first come on-line. In an isolated system with limited storage capability, such surplus energy cannot be utilized; instead, the water would be spilled and the value lost. In an interconnected system, surplus power can be exported at the value obtained by negotiated contract prices or at the current market value.

Unlike traditional transmission assets, loading of the US Interconnection varies proportionally with the level of surplus generation on the Manitoba Hydro system not with Manitoba Hydro's peak loads.

3. Facilitate economic exchanges during all time periods

Interconnections provide an important source of supply during off-peak hours when there is ample excess capacity in the adjacent predominantly thermal system; such off-peak purchases allow water/energy to be conserved in Manitoba to meet loads in future periods. In addition, due to higher domestic loading conditions during peak load hours, the US interface loading cannot necessarily follow peak hours.

US Interconnection loading is generally higher in the summer when Manitoba Hydro has more surplus energy and generation capacity. Conversely, in periods of lower flows, the loading on the US Interconnection is highest overnight, when MH is purchasing lower cost energy and conserving reservoir storage for use during peak hour conditions.

4. Allow for sharing of capacity resources due to load diversity

Loads in different power systems will tend to peak at slightly different times on a daily or seasonal basis. Daily diversity means that power demand peaks at different times of the day: peak times tend to vary slightly from system to system depending on factors as time zone, local economy, work hours, holidays, and local weather conditions. Seasonal diversity means that power demand peaks in different seasons: e.g., cold weather drives peak winter (heating) loads in the north, while hot weather drives peak summer (air conditioning) loads in the south. Such load diversities permit the sharing of capacity resources to meet overall peak system loads—and cost savings through the reduction in total resources needed to meet system demand. In this context, it is much more than the top 50 or 100 peak hours that are considered, but a definition of peak more consistent with peak periods defined in the weighted energy allocator.

5. Allow for sharing of generation contingency reserves with other utilities

A reality of power system operation is that individual generators or transmission components will have failures from time to time. To allow for such sudden generation or transmission outages, power system operators must have available spare generation that is ready to operate—units that are called operating or contingency reserves. If operated in isolation, each individual power system must carry sufficient contingency reserves to at least cover the largest single loss-of-supply event or contingency in their power system. For an interconnected power system, power system operators can pool their contingency reserves such that a single pool of contingency generators is available to cover loss-of-supply events over the entire interconnected system—resulting in a significantly lower level of contingency reserves being carried overall and considerable cost savings.

Intervener Positions

Most Interveners are supportive of Manitoba Hydro's Treatment of the US Interconnections, with Mr. Harper stating on September 8 (Transcript, page 354),

> "*Use of this allocator recognizes that investments in interconnections were made to support both energy and capacity reliability for domestic load with energy reliability actually being more critical. It also recognizes that exports are a fundamental part of Manitoba Hydro's business model, and that Manitoba Hydro's firm export commitments are typically blocks of power over five (5) by sixteen (16) or seven (7) by sixteen (16) periods.*"

Supportive

- Coalition
- GAC
- GSS/GSM

Disagree

- MIPUG

Manitoba Hydro's Rationale

- Provides access to US generating resources which is a source of generation reliability
- Provides an outlet for surplus Manitoba generation
- Facilitates economic exchanges of energy
- Allows for sharing of capacity resources
- Allows for sharing of generation contingency

MIPUG's Rationale

- Industry uses a demand allocator

In their final argument, MIPUG cites two main concerns with Manitoba Hydro's treatment of the US Interconnections:

- Interconnections are not different in form or function than domestic AC lines that are classified as Demand and allocated on 2CP; and
- It is inconsistent with the way OATT is calculated[65].

In support of their first argument MIPUG quotes Mr. Camfield (September 9th Transcript, pages 788-789):

> *"In the case of the AC system, the reason we classify those facilities, and this is referring to the AC meshed network, is because the reliability issues, given Manitoba Hydro's planning criteria and the way they operate their system, the reliability benefits associated with -- with transmission are predominantly associated with the peak loads.*
>
> *In the interface, it's a different story. There, the reliability benefits. That is, should we need that -- that interface for reliability purposes, it is not related explicitly or -- or specifically to fully narrow periods, such as exceptionally cold, high -- high load days in the winter in isolation.*

[65] MIPUG Written Submission, September 21, 2016, pg. 5-6

> *Rather, the reliability benefits are more broadly spread. And that's because the reliability benefits of the interface are -- are a form of guarantee insurance for supply –side reliability issues, and those can be for extended periods of time."*

Manitoba Hydro disagrees with MIPUG's assertion that Mr. Camfield's response,

> *"ignores the evidence that the import capability is in fact a major component of providing backup and reliability for meeting load at peak times."* [66]

Rather, Mr. Camfield's response demonstrates that the interconnections provide reliability benefits in more than just peak times but not exclusive of those times. In this respect the Weighted Energy allocator, which recognizes the importance of peak periods, as discussed in Section 6.5, is far better suited for the interconnections than a 2CP allocator that only considers the peak hours.

Manitoba Hydro's OATT calculation is based on 12CP, which is more closely aligned to average energy than it is to 2CP[67], and regardless should not be the basis for which to determine the appropriate classification of the US Interconnections.

8.0 USE OF AN EXPORT CLASS

Prior to 2005, Manitoba Hydro's cost of service study did not define an Export class and did not allocate any fixed embedded costs to exports. At that time export revenue less variable costs was shared among domestic classes in proportion to each class' allocated Generation and Transmission costs. This resulted in what Manitoba Hydro viewed to be an unfair sharing of export revenue and cost of service results that Manitoba Hydro could not support. The issue facing Manitoba Hydro and Cost of Service was likely best captured by Mr. O'Sheasy (transcript page 708) where he describes export sales that generate $100 of revenue that are allocated $80 of cost. Previously, the $20 residual would have been returned to domestic customers on the basis of their allocated Generation and Transmission costs.

He goes on to describe the situation where those export revenues increase to $200 and yet their cost is still $80. In the absence of an export class, the $120 residual would continue to be returned to domestic customers on the basis of their allocated Generation and Transmission costs. And, those domestic customers who are allocated a greater share of Generation and Transmission costs would benefit to a much larger degree.

[66] MIPUG Written Submission, September 21, 2016, pg. 5-5
[67] Manitoba Hydro Rebuttal Evidence, pg. 27

Since that time, Manitoba Hydro has extensively considered, analyzed and debated the use of an Export class. While export revenue has declined in recent years, Manitoba Hydro believes that it is appropriate to continue with an Export Class concept, for its intended purpose. Exports and their revenue continue to be significant to Manitoba Hydro's operations, to its net income and financials. Exports also can and have had a significant impact on COS.

Manitoba Hydro continues to view the use of an Export class an appropriate mechanism for more equitably sharing Export Revenue:

- Moderates the potential for unfair sharing of export revenue
- Transparent and objective
- Recognizes and reflects the significance of Exports to Manitoba Hydro's operations
- Consistent with Manitoba Hydro's established overall framework for COS

1. **Use of an Export class is a reasonable and transparent mechanism to share export revenue amongst Manitobans**

The use of an Export Class shares Export Revenues among Domestic customer classes in two ways:

- First by allocating a reasonable share of embedded costs to the export class thereby reducing Manitoba customer classes' responsibility for G&T costs;
- And secondly the remaining Net Export Revenue is returned to each domestic customer class on a basis such as allocated GT&D costs.

2. **The use of an Export class and the distribution of residual Net Export Revenue on the basis of GT&D can reduce absolute and relative distortion of cost responsibility by class for Manitobans**

As shown very effectively in Table 1 below[68], export revenue can have a considerable effect on domestic customer classes:

[68] Manitoba Hydro Rebuttal, page 10

Table 1: Comparison of PCOSS14 Methodology to No Export Class Methodology under Current and Higher Export Prices

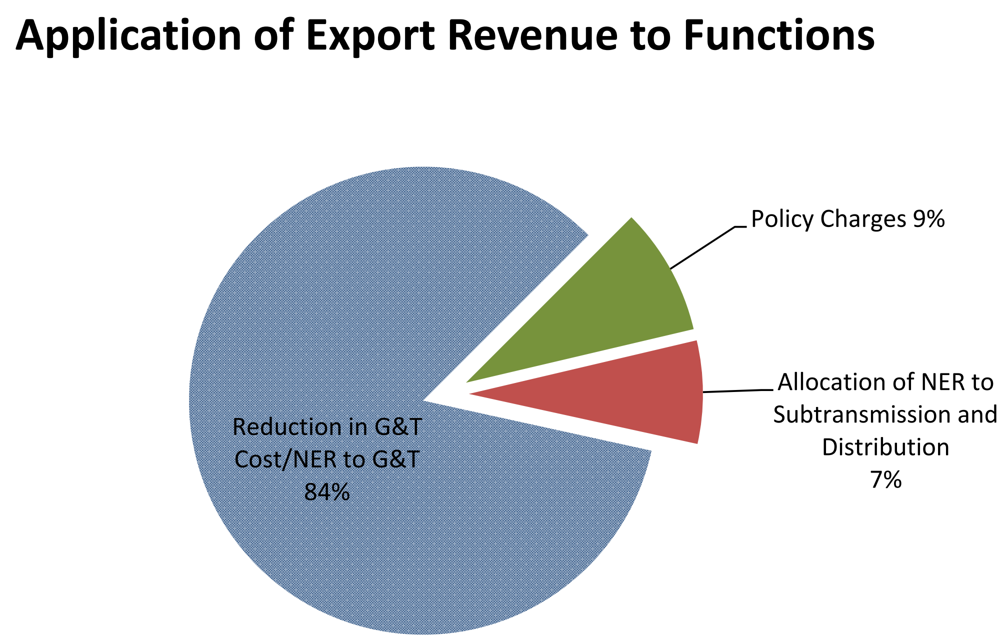
Customer Class	PCOSS14-Amended	PCOSS14-Amended No Export Class	PCOSS14-Amended High Opportunity Prices	PCOSS14-Amended High Opportunity Prices No Export Class
Residential	99.9%	98.8%	100.1%	97.3%
General Service - Small Non Demand	108.0%	106.4%	107.7%	105.0%
General Service - Small Demand	104.5%	104.0%	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%

This table demonstrates the degree of variability in cost responsibility of domestic customer classes because of the treatment of export revenue. And the determination of cost responsibility of domestic customers by class is the very reason that Cost of Service exists.

The table also shows that as export revenue grows, without an Export class that revenue disproportionately benefits those classes with largely only Generation and Transmission cost allocation. This occurs even though there is no underlying cost responsibility change. The intent of an Export class is to put a bookend on how much export revenue is reasonably shared among domestic customers on the basis of their allocated generation and transmission costs alone.

It may seem intuitive to conclude that the only cost causative perspective is to allocate export revenue to domestic customers on the basis of generation and transmission investment, given that generation and transmission assets functionally make exports possible. However, export sales are enabled by surplus energy and capacity that domestic customers do not use. And the allocation of export revenue to domestic customers on the basis of generation and transmission only is in effect giving domestic customers credit of export revenue on the basis of the assets they do use. Opportunity sales, for example, are significantly a product of domestic customers not requiring energy and capacity in the summer and off-peak periods, which most notably result from customers served from the distribution system.

It is noteworthy that even with the use of an Export class, export revenue continues to largely distribute export revenue on basis of the allocated Generation and Transmission costs. In fact, in PCOSS14-Amended, approximately 84% of all export revenue is shared among domestic customer classes on the basis of their allocated Generation and Transmission costs as shown in the table below[69]. The remaining 16% of Export Revenue is allocated to domestic customers on a basis other than their Generation and Transmission costs. However, it is important to note that this is true in today's conditions. In conditions such as those experienced in the early and mid 2000's, the potential to distribute export revenue on a basis other than each customer class' allocated Generation and Transmission costs (the assets that make export revenue possible) will increase and is exactly what the use of an Export class is intended to do.



3. The use of an Export class is consistent with Manitoba Hydro's established overall framework for COS

The incorporation of an Export class in COS corresponded to a number of methodologies that were selected to recognize Manitoba Hydro's role as part of a larger interconnected market:

[69] Manitoba Hydro Submission, 2015 Cost of Service Review, December 4, 2015, pg. 19

Manitoba Hydro's use of an Export class is consistent with:

- Generation: Weighted Energy Allocator
- Transmission: 2CP Demand
- Treatment of US Interconnections

Manitoba Hydro's view was and continues to be that these methodologies reasonably characterize cost causation of Manitoba Hydro's system given Manitoba Hydro's operations. The methodologies recognize not only why costs were incurred in the past but also what load characteristics are currently driving costs and can be expected to drive them in the future:

- The Weighted Energy allocator used in the allocation of Generation-related costs reflects the varying value of energy in external markets. Recognizing the value of energy during different seasons and times of the day is important because decisions customers make on when to consume have an important effect on costs incurred by Manitoba Hydro, cost of service and ultimately rates, either through reduced market sales or increased use of imports or internal resources (thermal and hydro).

- The reflection of a summer peak in the 2CP Demand allocator is due to export loads. This methodology has been employed since approximately 2002. It recognizes that Manitoba Hydro's costs are not only affected by domestic winter peak loads, but that costs are also affected by the freeing up of capacity during the summer periods to leverage premium summer export sales.

- The proposal to classify and allocate US Interconnections on Weighted Energy recognizes that the role of these facilities in the regional market is to allow Manitoba Hydro access to other utilities' generation resources as well as to provide others access to Manitoba Hydro's generating resources.

The use of an Export class as the mechanism to share export revenue among Manitoba customers is part of this established framework for COS. It recognizes the significance of exports to Manitoba Hydro's planning, operations and its costs. The unwinding of an Export class would be inconsistent with the overall framework of current COS and these methodologies that consider the significant impact of interconnection on the development and operation of Manitoba Hydro's system to viewing Manitoba Hydro's system as isolated.

8.1. The No Export Class Option

No party to the proceeding advanced evidence in support of the elimination of an Export Class. In an undertaking prepared by Mr. Bowman (Undertaking 33, page 4), he suggested that MIPUG members may be interested in its elimination but no evidence was advanced other than to state it would be simpler. Mr. Bowman continued to support the use of an Export Class perhaps on the basis of:

> *"Hydro's evidence accurately portrays that in a different context (such as a time of very high export prices combined with lower Hydro embedded costs, as existed in 2006), an export class may have a larger practical importance."*[70]

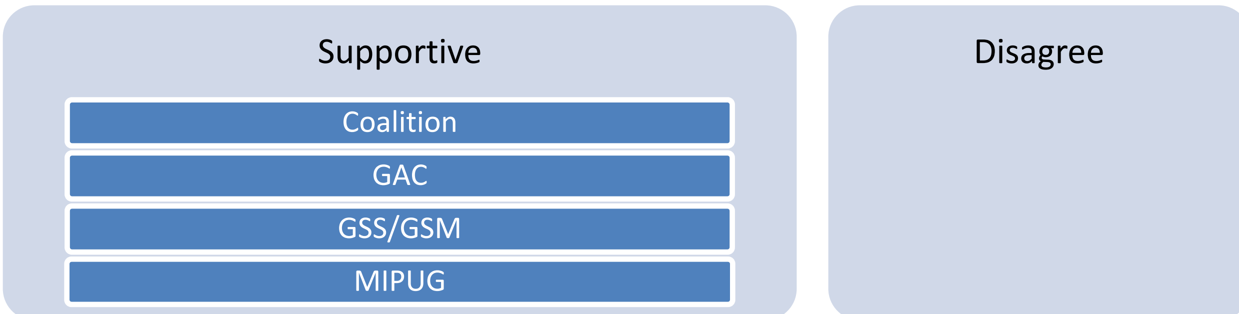
During cross examination by Mr. Peters all parties agreed with the concept of an Export Class. There was near unanimous agreement (September 9, Transcript page 704) that the elimination of an export class would not reduce the number issues to be addressed in the COS:

> *MR. BOB PETERS: Let's try this one. Mr. Chernick, we'll start at your end of the table. Again, five (5), you're agreeing, one (1), you're disagreeing. The number of issues that need to be addressed in a cost of service methodology is measurably decreased if the export class is eliminated?*
>
> *MR. PAUL CHERNICK: One (1). You have to deal with all the same issues, you just put them in different places.*
>
> *MR. ROBERT CAMFIELD: No change, one (1).*
>
> *MR. MICHAEL O'SHEASY: One (1).*
>
> *MR. PATRICK BOWMAN: I -- I disagree. I think it's considerably simplified, so four (4).*
>
> *MR. A.J. GOULDING: One (1).*
>
> *MR. WILLIAM HARPER: One (1).*

One has to assume that Mr. Bowman continues to support the concept of an export class, even while believing its elimination would simplify cost of service because, he like everyone else, believes an Export class serves an important purpose.

[70] Rebuttal Evidence of Mr. Patrick Bowman, August 5, 2016, pg. 6

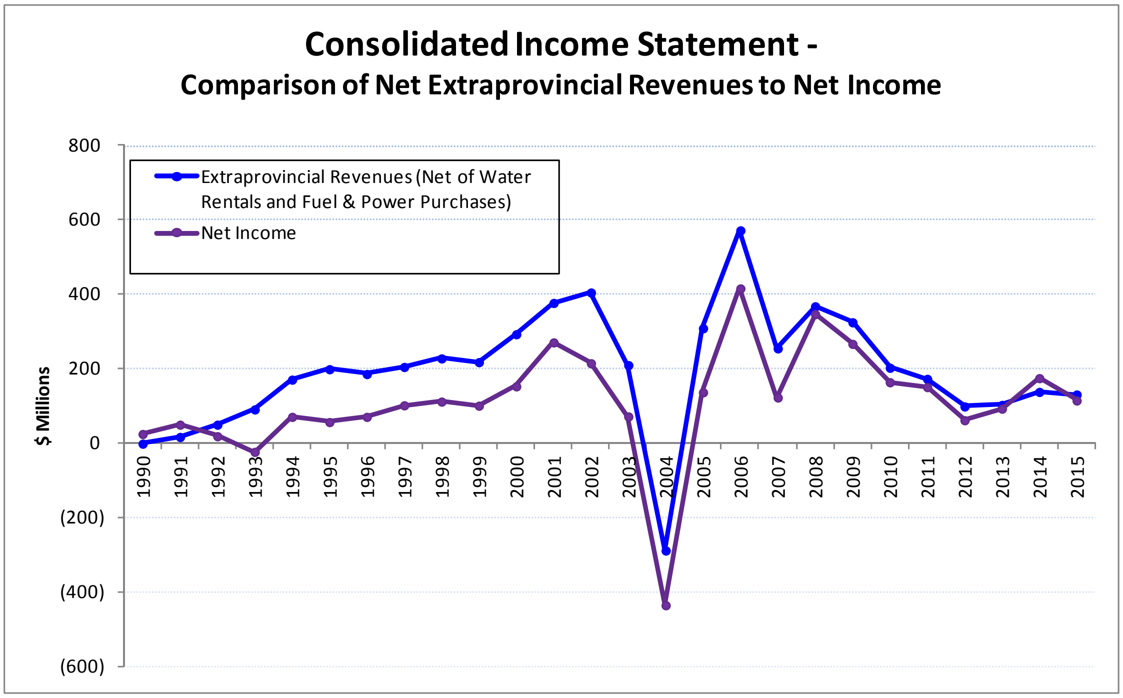
It is noteworthy that all experts to this proceeding in final argument appear to view the concept of an Export class in COS as appropriate. MIPUG is silent in their final argument, but it can be inferred reasonably they agree (or at least don't disagree) given their lengthy argument on how cost ought to be allocated to an Export class.



Although Manitoba Hydro was not asked for its perspective on the issue of the elimination of the Export class, it is worth noting that Manitoba Hydro agrees that the elimination of an Export class does not eliminate the issues and potentially treats them in a much less transparent manner depending on how export revenue is allocated.

Additionally, as discussed above and as Ms. Derksen discusses (Transcript pages 79-80), Manitoba Hydro's perspective is that in the absence of an Export class, it should not be automatically concluded that the most cost causal, and therefore most appropriate COS treatment of export revenue is to allocate that revenue to domestic customers on the basis of the assets that give rise to that revenue. Ms. Derksen notes a compelling argument can be made that total export revenue, not just NER, be allocated on the basis of total cost to serve by class because total export revenue is very strongly correlated to Manitoba Hydro's Net Income (equity), as shown in the table below:[71]

[71] Manitoba Hydro's Submission, 2015 Cost of Service Review, December 4, 2015, pg. 18



Manitoba Hydro is not advancing the alternative of no Export class given that all parties are in favour with the use of an Export class. With a reasonable assignment of cost to the Export class, Manitoba Hydro is satisfied that the residual NER, allocated to all customer classes on the basis of their total cost to serve, provides some recognition that export revenues are made possible not narrowly only by generation and transmission assets, but also because of the impacts to Manitoba Hydro's overall revenue requirement and that exports are made possible through freed up surplus energy and capacity occurring at times of low use on the Distribution system.

9.0 COST ASSIGNMENT TO DEPENDABLE AND OPPORTUNITY SALES

9.1. Assigning Full Embedded Cost to Dependable Exports and Variable to Opportunity Sales is Reasonable, Balanced and Consistent with Manitoba Hydro's COS Objectives

What appears fundamentally at issue in this proceeding is whether opportunity sales ought to be assigned fixed cost? Manitoba Hydro continues to believe it is appropriate to acknowledge and recognize the clear difference between export types in order to reasonably allocate embedded cost to the export class.

In arriving at this decision for Cost of Service purposes, Manitoba Hydro has, in effect, agreed to treat Dependable sales as a joint product equivalent to its main product, the provision of power to Manitobans. For Cost of Service purposes, Manitoba Hydro effectively treats Opportunity sales as a by-product:

Dependable Exports	Opportunity Exports
Joint Product assigned costs equal to a Manitoba customer	By-product assigned Variable Costs

Manitoba Hydro's Rationale for Differentiating Export Costs:

- Clearly different types of sales, thus cost to serve differs
- Limited consideration of Opportunity exports in resource decision
- Overall approach is balanced

With focus on Manitoba Hydro's stated objectives, this approach of cost allocation to exports is reasonable and balanced:

1. **Dependable and Opportunity are clearly different types of sales as is their cost to serve**

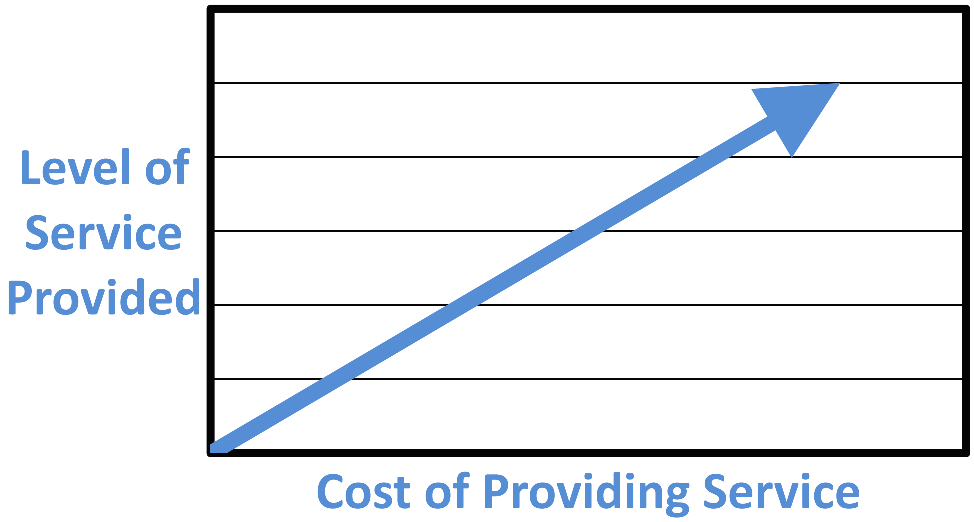
It is appropriate to recognize cost responsibility distinction between Dependable and Opportunity exports. A key factor that drives the difference in cost to serve Dependable and Opportunity exports is the difference in level of service. MIPUG asserts that the level of service provided to exports is irrelevant to the cost of service[72]:

> *"for the purposes of measuring the necessary contribution of the export, the quality of service provided to opportunity exports is an unhelpful basis for assessment, and essentially a distraction. It is not important to assess the value received by the export customer …"*

MIPUG is confusing the issue here by mixing value to export customer with the level of service provided. It is true that the value of a sale to an export customer will differ depending on the type of export product: it may defer their need to construct new generation in the case of a long term dependable contract with Manitoba Hydro, or it may allow them to avoid running their coal unit tomorrow in the case of a day ahead opportunity sale from Manitoba Hydro. Regardless, Manitoba Hydro's argument is to look at the *level of service* of the export product to guide the assessment of the cost to serve. To ignore level of service suggests that service levels are not a factor in the cost incurred to provide service. This is simply false. The level of service is inextricably tied to the cost to provide the service and, given that this is a cost of

[72] MIPUG Written Submission, September 21, 2016, pg. 2-13.

service review, it is very relevant to look at level of service which for this reference is based upon reliability. Just like it costs more to make a very reliable car, it costs more to produce a highly reliable export product; reliability drives cost.



Opportunity energy is a much lower level of service than Dependable energy exports and Manitoba Hydro incurs very different costs to provide these two services. Therefore, it would be inappropriate to assign costs to Opportunity exports on the same basis as Dependable exports. The difference in the level of service of the two types of sales has been highlighted by Mr. Harper:

> *"Furthermore, it is also clear that there's a difference between firm and Opportunity exports in terms of the service provided. Manitoba Hydro does include firm export commitments in its planning process for generation and transmission; it does not do so for Opportunity exports. Also, in terms of when it comes to who gets cut first if curtailments are required in order to support domestic load, Opportunity exports are curtailed before firm exports. This would indicate that there's also a difference in the quality of service provided to firm versus Opportunity exports".* [73]

Dependable exports are backed by accredited generation capacity, can be relied upon to serve peak loads and hence can be used to meet regional reliability requirements. Opportunity energy is sold on an as-available basis with little to no commitments made to its availability, and is not available during the highest loading conditions. In a low water year very little

[73] 2015 Cost of Service Review, September 8th, 2016, Transcript pg. 336

opportunity energy may be available, whereas in a high water year there could be relatively large quantities available.

If Opportunity export customers and markets demanded a level of service similar to that provided to Domestic customers or Dependable exports, Manitoba Hydro would incur significant additional costs in order to provide this higher standard of service.

MIPUG acknowledged that their customers are generally not interested in a lower quality product (i.e. a lower cost product)[74]:

> MS. ODETTE FERNANDES: *Thank you. Now, we heard from Mr. Cormie on Wednesday about how opportunity sales will be entered into on the basis of product availability. … And so if I look at line, Mr. Cormie's (sic) indicated:*
>
> > "And so the water has to be in the reservoir or there has to be a significant snow pack on the ground before we're convinced that we can enter into short-term firm sales that commit the Company to supplying it beyond the dependable energy criteria."
>
> *Do you recall that testimony?*
>
> MR. PATRICK BOWMAN: *Yes.*
>
> MS. ODETTE FERNANDES: *In addition to seasonal forward sales, a large portion of opportunity sales are made up of the sales in the day ahead market where, if Manitoba Hydro has surplus water and generation it may offer to sell the energy in the day ahead. Would you accept that?*
>
> MR. PATRICK BOWMAN: *Yes, that's another of the types of -- of opportunity sales*
>
> MS. ODETTE FERNANDES: *And so in terms of these different types of sales -- and I noted yesterday that -- I believe it was yesterday, that you indicated that you were -- you were having discussions with MIPUG members about some of these issues and you've had various conversations with you (sic).*
>
> *Now, in your conversations, can you indicate whether MIPUG members would be com --*

[74] 2015 Cost of Service Review, September 9th, 2016, Transcripts starting at page 668.

comfortable with having six (6) months or less advanced notice or assurance that their loads can be served?

MR. PATRICK BOWMAN: *I -- I would hesitate to speak for the members. But I think it's fair to say that they -- they plan their plants around -- around a certain energy price at a certain availability. … But, in general, all of those -- all -- I would say it's fair to say all of the -- the MIPUG members rely on a large portion of their power being at a known -- a price known in advance for a supply that is as firm as -- as Manitoba Hydro can make it.*

MIPUG members rely on their power being firm and known in advance. Opportunity exports are not provided this level of service and are not planned to be of this higher standard. It is not reasonable to argue, as MIPUG does, that Opportunity exports be assigned embedded G&T costs at par with their member's loads.

2. Role of Opportunity exports in investment decisions

A significant issue is whether Opportunity exports, because they were a consideration in the investment decisions for Limestone, Wuskwatim and Keeyask, should be assigned full fixed costs, or something close, on the same basis as dependable energy and capacity demands of the firm Manitoba load. A consideration in the three most recent investment decisions does not equate to an equivalent assignment of full costs for a number of reasons:

- For 13 of 16 hydro generating facilities potential opportunity sales revenue was not considered as part of the justification for the investments. Indeed 10 of the 16 stations were completed before 1970 when the first of the US interconnections that facilitate exports were completed.[75]
    - These legacy stations, regardless of how much they have been depreciated compared to more recent plants, continue to produce a significant amount of surplus energy to the system, of which approximately one-half is dependable and one-half is opportunity energy.[76]
- Limestone, Wuskwatim and Keeyask were justified as the least cost resources over the long term to meet the energy and capacity needs of Manitoba customers, in consideration of revenue from dependable sales, and opportunity sales when the opportunity hydro energy is available. The economic analysis considered that opportunity hydro energy would be used in some years to serve the Manitoba load under moderate drought conditions, displacing imports and thermal generation
- Opportunity exports were known at the time of the Limestone, Wuskwatim and Keeyask justifications to be a low quality product with lower costs of service. In short –

[75] 2015 Cost of Service Review, September 7th, 2016, Transcript pg. 49
[76] 2015 Cost of Service Review, September 7th, 2016, Transcript pg. 235

opportunity energy is a leftover product whose value and cost of service was recognized at the time of the investment decision to be lower than Dependable exports.[77]

- Manitoba Hydro finds GAC's final argument (September 22, page 6) is helpful to the discussion on the role Opportunity exports play in the investment decision.

> *"But at other times, the same common facilities produce products of lower value, such as the lower dependability of curtailable rate and opportunity export sales. The butcher doesn't charge customers the same for a prime rib roast and hooves supplied to the glue factory despite the fact that they come from the same steer with common input costs."*

Further, in a low margin business, it may be revenue from the hooves supplied to the glue factory that finally made the steer profitable. That too is not grounds for allocating full fixed costs to a lesser grade product. The potential for opportunity energy to tip the resource planning decision from one resource to another does not change the fact it is a lesser product with lower costs of service.

- Opportunity sales revenues are one of numerous drivers of contemporary hydro development; there are many factors including environmental considerations, Manitoba economic impacts, and fuel price uncertainty that influence the decision. The PUB repeatedly acknowledged these other considerations in their NFAT Report and Intervener consultants have also acknowledged this fact[78].

A look at historic market prices compared to total Generation and Transmission unit costs shows that Opportunity sales have made a contribution to fixed cost by virtue of market price exceeding variable cost.[79] However, the amount of this contribution is variable and is usually insufficient to cover a full share of Generation and Transmission cost.

3. Overall is a Balanced Approach

Manitoba Hydro believes that it has landed on approach for allocating cost to the Export class that is reasonable, balanced and reflects the COS objectives for an Export class.

MIPUG seeks to assign embedded Generation and Transmission costs to Dependable and Opportunity exports on an equivalent basis as well as on par with General Service Large (GSL). It is helpful to compare these types of service to test the validity of assigning costs on the same

[77] 2015 Cost of Service Review, September 7th, 2016, Transcript pg. 50

[78] Patrick Bowman agreed during cross examination on September 9, 2016 at transcript pg. 667; Mr. Harper noted in his PreFiled Evidence dated June 10, 2016 at pg. 29 (Footnote 76) that both the NFAT decision on Keeyask and the CEC decision on Wuskwatim that other factors are considered when proceeding with these projects.

[79] Manitoba Hydro Rebuttal Evidence, July 29, 2016, pg. 7

basis across these loads. The table below provides a comparison of the differing attributes between a GSL customer in Manitoba, a Dependable export and an Opportunity export. These attributes have direct or indirect influence on the costs to serve.

Attribute	Load Class/Export Type[80]		
	Large Industrial	Dependable	Opportunity
Commitment	In perpetuity	Defined/planned by MH to fill in blocky development	Months out to as short as 20 min prior to delivery
Service Level	• Firm interconnection • Accredited capacity • Supply under drought of record • No curtailment	• Firm transmission • Accredited capacity • Supply under drought of record • Provisions for curtailment	• Firm or non-firm transmission • generally not backed by accredited gen capacity • Supply as conditions allow • Provisions for curtailment
Impact on Development plan	• MH required to develop resources to meet demand	• Influences resource selection • May prompt generation advancement if economic • Some sales may be neutral in requirement of additional dependable energy from MH system (ie. 'hybrid sales') where existence is complemented with increased access to additional diversity imports	• Considered in economic evaluation of new resources (recent new plant)
Backed with planning reserves	Yes	No	No
Take or Pay	No (a risk that revenues will not materialize)	Yes	Yes, generally whole payments if curtailed by markets; obligations are short term
Timing alignment of energy supply and demand	Not well aligned – generally flat across the year vs. inflows being higher in spring/summer	In phase with higher inflow season (relatively less requirement to shift energy using storage as compared to domestic load)	Not an issue as MH can dictate timing as resources are available
Capacity coincidence with weather dependent demand	Somewhat correlated, requiring building for capacity	Generally out of phase with MB demand, therefore not requiring building additional capacity	Not an issue as MH can dictate timing around MB demand and long term capacity commitments
Colour Key			
Supports assignment of full embedded G&T			
Some rationale to assign embedded G&T			
Weak or no driver to assign embedded G&T			

[80] As discussed in 2015 Cost of Service Methodology PUB/MH-I-2b; Manitoba Hydro Presentation September 7, 2016, p. 48; Manitoba Hydro Submission, December 4, 2015, pg. 15

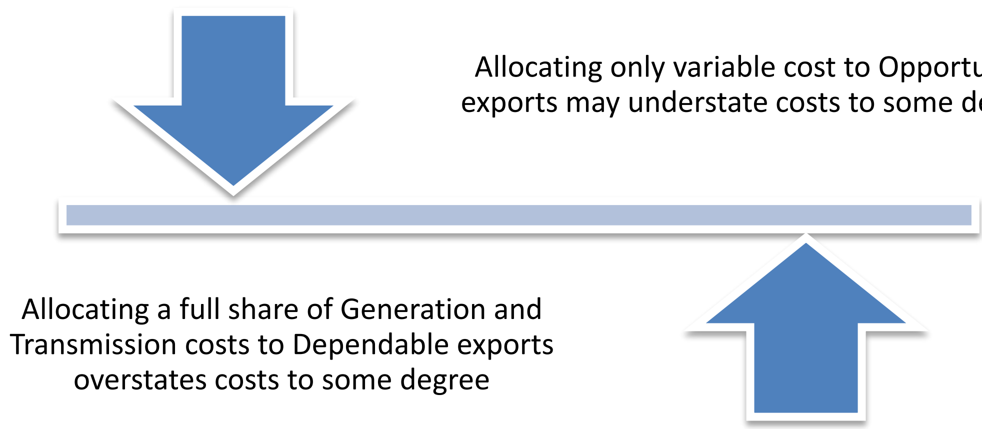
As demonstrated in the table above, Dependable exports have a lower service quality and are generally less costly to serve than a Manitoba customer. Opportunity exports have markedly lower service quality and come with significantly lower obligations on Manitoba Hydro to serve.

Manitoba Hydro's proposal to assign Dependable exports full fixed costs on an equivalent basis to the Manitoba load may significantly overstate fixed costs assigned to the export class, as the Manitoba load is more costly to serve for the reasons summarized in the table above. However, due to the complexities of the hydraulic system, it is not possible specify precisely this over assignment.

It could be argued that assigning only variable cost to Opportunity exports may under assign fixed costs to the Export class. Opportunity exports from Limestone and subsequent hydro stations were a consideration, among many other factors, in the decision to commit to these plants. At the same time it was also known that the opportunity energy was a lower grade product, available only after other needs, including the capacity need of the Manitoba load and long term Dependable export contracts, were met, and was known to be a lower valued product.[81] Additionally, based on the table above, Manitoba Hydro believes the costs to serve Opportunity exports are dramatically less than that of Dependable exports and even less so relative to GSL customer. Clearly, it would be inappropriate to assign fixed cost to Opportunity sales on an equivalent basis as either the Manitoba load or Dependable energy exports.

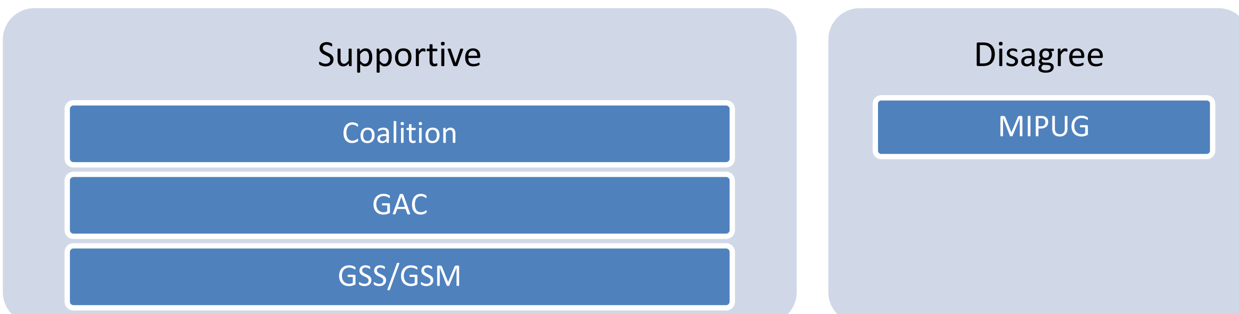
From Manitoba Hydro's perspective, given the difficulty of precise identification of the facilities and their costs, and given that Dependable exports continue to be costed at full share of embedded costs that overstate fixed cost responsibility of Dependable sales, it is reasonable to assign Opportunity sales on an incremental cost basis, which in total results in a reasonable overall allocation of fixed cost to the Export class.

[81] 2015 Cost of Service Review, September 7, 2015, pg. 50



Intervener Positions

Most Interveners agree that it is reasonable to distinguish between the costs assigned to Dependable and Opportunity Exports.



GSS/GSM appears to agree that distinguishing between exports for purposes of cost assignment is reasonable, but recommends basing the split on the share of exports that can be viewed as relatively predictable.

It should be noted that the initial LEI evidence[82] which presented a statistical analysis of 10 years of actual and 5 years of forecast data and lead them to conclude 66% of total export sales should be treated as dependable improperly mixed historical actual export and forecast average export volume data. In response to Undertaking #34 LEI attempts to correct this error by reflecting 16 years of historical export data and concludes that full embedded costs should be assigned to 63.8% of exports. Between 2001 and 2015, the Manitoba Hydro system underwent several significant changes, each one of which would have an impact on export volumes. For the statistical analysis to be valid – the system would have had to not undergone any significant changes during the analysis period that would affect export volumes. To the

[82] Pre-filed Evidence of London Economics International, June 10, 2016, pg. 7

contrary, Manitoba load has grown – reducing exports, offset to some degree by new sources of supply, including Brandon CTs (260 MW, in 2001), wind generation (258 MW, in 2005 and 2011), and the Wuskwatim generating station (200 MW in 2012). The LEI statistical analysis using 16 years of data with a changing system during a period of high water is not valid, and no reliable conclusions can be thus be drawn.

MIPUG's arguments appear to rest on three perspectives. First, Opportunity sales should be assigned a full share of fixed cost based on the fact that opportunity sales drove the decision to build Keeyask[83], rather than a gas plant. Secondly, MIPUG views it unreasonable to assume that no fixed costs have been incurred or used to facilitate opportunity sales.[84] And third, the PUB has previously directed full fixed cost assignment to all exports.[85]

As discussed fully in Section 9.1 above, Manitoba Hydro agrees that opportunity sales were a factor that affected the decision to pursue Keeyask, Wuskwatim and Limestone. However, this was one of many factors and 3 of 16 plants, and to suggest, as MIPUG has, that Manitoba Hydro would have built a gas turbine in the absence of opportunity sales is uncertain at best. At page 19 of the PUB's NFAT Report, the PUB states

> *"In reaching its recommendation with respect to the Keeyask Project, the Panel concluded that natural gas generation does not present an acceptable alternative, as it is less economic than hydroelectric generation and relies on burning fossil fuel. Furthermore, any short-term capital cost advantages are offset by significant ongoing cost risk, primarily fuel costs."*

Manitoba Hydro's methodology does not imply that it has assumed that no fixed costs have been incurred or used in facilitating opportunity sales. Manitoba Hydro's decision to assign variable cost only to opportunity sales also considers:

- the significant lesser quality service level of opportunity exports (and therefore less costly to serve),
- that opportunity sales are one of many factors that were considered in the decision to build resources for Manitobans yet not a factor in most of Manitoba Hydro's generation facilities,
- that additional fixed costs would have to be incurred to increase the level of service of opportunity sales to that of firm service; and

[83] MIPUG Written Submission, September 21, 2016, pg. 2-11
[84] MIPUG Written Submission, September 21, 2016, pg. 2-2
[85] MIPUG Written Submission, September 21, 2016, pg. 2-4

- that a full share of fixed embedded costs to Opportunity exports would ignore completely the over assignment of embedded cost to dependable sales.

When reviewed in totality, considering the facilities are built for Manitoba load, and the objective of this COS exercise is about fairly sharing export revenue among Manitoba customers, Manitoba Hydro believes it has arrived at a reasonable solution. Even Mr. Bowman effectively appears to concede that full embedded cost assignment to opportunity sales may be excessive.[86]

Manitoba Hydro acknowledges that previous PUB directives on this matter, in particular Orders 117/06 and 116/08, directed that all exports be allocated a full share of fixed costs equivalent to domestic customers. However, Manitoba Hydro also notes that the PUB in its Procedural Order 26/16 made clear the importance of conducting a fulsome COS review:

> *"The hearing represents the first review of Manitoba Hydro's cost of service methodology in almost a decade. As such it is the Boards intention to conducts a comprehensive review and not limit the issues for consideration"*

This Board, having participated in a significant NFAT proceeding, general rate proceedings, and now a Cost of Service process has a thorough understanding of Manitoba Hydro's operations and is well-positioned to provide guidance and advice based on facts that are current and relevant today. Manitoba Hydro encourages the PUB to rely on this evidentiary basis as the current context to assess the reasonability and consistency of Manitoba Hydro's cost allocation approach under review by the current Board.

Manitoba Hydro, under cross examination by Mr. Hacault[87], provided its perspectives on a number of conclusions previously relied upon as summarized in the following table. Manitoba Hydro believes that the facts and evidence in the current proceeding and the NFAT support its perspective.

[86] Rebuttal Evidence of Mr. Patrick Bowman, August 5, 2016, pg. 2-3
[87] Testimony of Mr. Cormie and Ms. Derksen, September 7, 2016 at pages 244- 254.

Previous Finding	Manitoba Hydro Clarification
NERA proposed a single export class	No • Prior to 2006 COS Hearing, NERA supported and recommended that cost distinction be made between dependable and opportunity sales, and superseded their 2003 report[88]
Opportunity sales are a result of overbuilding	No • Opportunity sales are achievable due to surplus water conditions

Opportunity and Dependable sales achieve similar average prices even though opportunity sales are more volatile in terms of price and volume.	No
	• Opportunity export prices have been consistently and significantly lower than long-term firm prices
	• Volume volatility of opportunity sales remains
	    • volumes are product of water flows
	• Price volatility of opportunity sales dampened
	    • discovery of shale gas

Firm and Opportunity sales are essentially interchangeable in the MISO market	No • Firm sales are used to displace new generation requirements in the US. • Opportunity sales generally capture the fuel replacement value

Additional export sales are secured based on anticipated favourable water. This can be viewed as a modification to the dependable energy definition.	No
	• Such sales are opportunity not dependable
	• Do not commit to long-term firm sales based on short-term water conditions
	    • Long-term sales made out of dependable water only
	• Favourable water conditions can lead to contracts with right to sell surplus energy at fixed prices
	    • Water reservoir levels are known
	    • No obligation to sell it
	    • Right to curtail it
	    • Surplus water not dependable water

Manitoba Hydro only requires 60-65% of actual hydraulic plant generation to satisfy firm energy and capacity requirements. Other 35-40% is for opportunity sales.	No
	• Manitoba Hydro plans for energy requirements of the system
	    • Dependable water flows
	• Manitoba Hydro plans for capacity requirements of the system
	    • Manitoba load plus reserve obligation

[88] Manitoba Hydro Exhibit-13, 2006 Cost of Service Hearing

The last conclusion, that Manitoba Hydro requires only 60-65% of hydraulic generation to satisfy firm energy and capacity requirements, is particularly concerning. MIPUG is relying on the conclusion that Manitoba Hydro overbuilds its facilities to serve exports for purposes of advancing their arguments that opportunity sales be assigned a full share of fixed costs. This is simply not correct, and at Transcript page 253, Mr. Cormie corrects this:

> "*Manitoba Hydro not only has to plan for the energy requirements of the system but we also have to man -- plan for the capacity requirements, which is the Manitoba load plus a reserve obligation. And as a result we -- we have more capacity available than we actually need because we have to prepare for -- we have to have a -- we have to meet our reserve obligation*." [89]

And yet, MIPUG is relying on this above quoted perspective of Manitoba Hydro in their final argument (page 3-4) to criticize Mr. Chernick's "pervasive dismissal of capacity"[90] for purposes of allocating generation-related costs.

On a final note, at page 2-9 of MIPUG's final argument, it is argued that Christensen Associates, having not participated in NFAT and not having read over 11,000 pages of transcripts, that their evidence with respect to opportunity sales should be discounted. Manitoba Hydro takes great exception to this suggestion. Any suggestion that a consultant is required to read the entire transcript in order to have an understanding of the evidence led at the NFAT so a determination can be made about the treatment of Opportunity exports is preposterous and should be dismissed. Manitoba Hydro staff discussed the evidence presented at the NFAT with CA at length. The consultants from CA were qualified by the PUB as experts in the same manner as all the other experts to this COS Review Process. CA are experts in COS and are more than qualified to provide an opinion that the PUB can rely upon. In fact, Manitoba Hydro submits that, as CA does not represent the interests of any stakeholder, but were rather hired as independent experts to provide their review on whether Manitoba Hydro's costing methodology was consistent with industry best practices, met Manitoba Hydro's specific needs and supported the equitable pricing of utility services, there is an argument to be made that their opinion should be afforded greater weight in this COS review process.

10.0 ALLOCATION OF NET EXPORT REVENUE

In Manitoba Hydro's December 4, 2015 Submission it proposed to continue to allocate NER on the basis of total class allocated cost, excluding directly assigned cost.

[89] 2015 Cost of Service Review, September 7th, 2016, Transcript pgs 253- 254
[90] MIPUG Final, page 3-3

Manitoba Hydro's Rationale for Allocating NER on Total Allocated Cost:

- System dividend to be shared in a fair and equitable manner
- Still largely G&T basis
- Charging URA and AEF against NER remains appropriate

Manitoba Hydro's Rationale

As noted in Section 8.0 above, crediting the export revenues on this basis, rather than strictly against G&T related costs, provides some movement to addressing the fairness issue that led to the adoption of the Export class a decade ago. Export revenues are still largely used to reduce Generation and Transmission costs, with only 7% allocated against Subtransmission and Distribution costs today.

Manitoba Hydro submits that the current treatment of the costs of the Uniform Rates Adjustment and the Affordable Energy Fund as a first charge against Net Export Revenue is appropriate as discussed more fully in the August 19th Written Submission of Manitoba Hydro (pages 13-17) and the Coalition (pages 23-24).

Intervener Positions

Interveners other than MKO and MIPUG, are broadly supportive of Manitoba Hydro's approach of allocating NER on the basis to total allocated GT&D costs. There is not agreement on the secondary issue of the inclusion of directly assigned costs.

The Coalition supports the allocation of NER as currently applied in PCOSS14-Amended. The COW and GSS/GSM support the allocation of NER on total cost including dedicated/directly assigned cost which would be particularly beneficial to the Area and Roadway Lighting Class. While, GAC is largely consistent but would also apply the revenues against dedicated cost that are related to utility service excluding street lighting equipment and other non-monopoly functions.

MKO appears to be recommending, some form of lump sum credit as a means of returning net export revenue even though almost no evidence was advanced in this process.[91] MKO cites that a lump sum is in keeping with *The Affordable Utility Rate Accountability Act* C.C.S.M. c. A6.8. Given this has not been tested in this or any other proceeding, Manitoba Hydro submits this should be dismissed.

MIPUG's final argument can essentially be summarized as follows:

1. NER should be excluded from the COS, but only once a full share of embedded costs have been assigned to all exports including Opportunity exports
    - A decision on how to use the excluded NER to benefit ratepayers is not required until overall domestic RCC (without NER) approaches unity
2. Alternatively revert to an allocation of NER on the basis of G&T[92]

Manitoba Hydro has demonstrated that the exclusion of NER from the COSS will produce class RCC ratios that are, after indexing, identical to results based on an allocation of NER in proportion to class revenues[93]. Further, Manitoba Hydro has shown that the allocation of NER in proportion to class revenues will result in outcomes nearly identical for most classes to the current approach of allocating NER on the basis of total allocated costs[94]. It is puzzling why MIPUG would then recommend two seemingly very different approaches to allocating NER – one a very broad allocation that effectively provides NER benefits to all costs including dedicated facilities, and the other a narrow allocation on the basis of G&T assets exclusively.

MIPUG's apparent acceptance of a broader 'Revenue' based allocation is subject to the important qualification that Opportunity exports are first allocated a full share of embedded costs[95]. As noted in Section 8.0, the Export class approach returns the benefits of exports to Domestic customers both by relieving the customers of G&T cost responsibility, as well as by the subsequent allocation of the residual NER. A closer examination of MIPUG's final argument reveals that MIPUG in effect continues to deny that export revenue should be credited against

[91] MKO Written Submission, September 21, 2016, pg 3-4
[92] MIPUG Written Submission, September 21, 2016, pg. 1-1 to 1-9
[93] Manitoba Hydro Rebuttal Evidence, pages 11-13.
[94] Manitoba Hydro Rebuttal Evidence, pages 13-14.
[95] MIPUG Written Submission, September 21, 2016, pg, 1-8

any asset cost other than Generation and Transmission assets. Through an excessive allocation of costs to Opportunity Exports which will largely eliminate NER, MIPUG's preferred approach will continue to almost exclusively offset only Generation and Transmission costs.

MIPUG's alternative option is to explicitly allocate NER on the basis of G&T. In this case, however, there is little apparent logic in continuing with the additional complexity of an Export class if the allocation approach allows does not moderate the effects of export revenue in embedded cost of service that lead to the adoption of the class a decade ago.

Manitoba Hydro remains confused as to how MIPUG proposes to use the "*positive NER that is not used to pay a portion of today's rates*[96]" to the benefit of ratepayers. Net Export Revenues as determined in the Cost of Service Study are not real funds that can be applied outside the strict confines of the same COSS. Manitoba Hydro remains convinced that excluding NER from the COS to support some undetermined alternate purpose simply does not accomplish anything.

10.1. Manitoba Hydro Accepts the Allocation of NER on All Costs Including Directly Assigned as Fair and Equitable

Manitoba Hydro has reviewed all the evidence and final argument of parties on the matter of how best to allocate NER.

Manitoba Hydro views that allocating export revenue to domestic customers based on only those assets that physically produce and transport the electricity to extra-provincial markets (that is, generation and transmission resources) as submitted by MIPUG constitutes too narrow a view of cost causation. This is particularly true in consideration of Manitoba Hydro's dominant hydraulic facilities and significant level of export sales. This view resulted in Manitoba Hydro's adoption of an Export class a decade ago.

Consistent with this view and direction, Manitoba Hydro accepts that the treatment of NER be extended to include all directly assigned costs. Manitoba Hydro agrees that exports functionally occur through generation and transmission assets. These assets impact borrowings and net income (and equity) and ultimately affect much of Manitoba Hydro's revenue requirement. As such, all facets of the Corporation, including not only Distribution, but also DSM and dedicated end use facilities support the investment in generation and transmission assets and ultimately allow participation in the export market. Investment costs, such as Net Income, are allocated to all customer classes based on total investment (which extends to and includes DSM and

[96] MIPUG Written Submission, September 21, 2016, pg. 1-7

dedicated end use facilities). Effectively, directly assigned facilities are already allocated a share of the cost of pursuing exports – it is appropriate they also receive a share of the benefits. On this basis, Manitoba Hydro supports the views shared by Mr. Goulding in the Concurrent Evidence session (Transcript pages 554-556) and as well as Coalition's Closing Submission (pages 35-37) on this issue. It is appropriate to recognize that there are cost and benefit impacts which extend beyond generation and transmission assets that give rise to export revenue. And it is appropriate that some export revenue be extended on the basis of those assets also. Manitoba Hydro accepts the recommendation of GSS/GSM and the COW that all directly assigned costs should receive a share of NER.

In conclusion, Manitoba Hydro remains convinced that its proposed approach to allocating Net Export Revenue, expanded to include dedicated end-use assets, reasonably meets the goals of a fair and equitable sharing of export revenue and avoiding distortion in class RCC's in response to changes in the level of export revenue.

MIPUG, in its Reply Submission on page 5, has drawn a false equivalence between costs incurred and directly assigned to the Area and Roadway Lighting class and customer contributions made by industrial customers, to suggest that extending eligibility to the former but not the latter is discriminatory. This is not true. In the former case Manitoba Hydro incurs capital costs to make the service available and these costs must be financed through borrowing and equity. In the latter case Manitoba Hydro effectively carries no net investment on its books.

In fact, all classes of service including, to a significant degree, Area and Roadway Lighting also make Contributions and these do not give rise to any cost incurred by Manitoba Hydro and are therefore also not being proposed by Manitoba Hydro or any other intervener to be eligible for any allocation of NER.[97]

Explicitly including NER (including directly assigned costs) in Cost of Service, or implicitly as MIPUG supports (by exclusion of NER and allowing RCC's to fall), produce nearly identical results. Manitoba Hydro's preference is to explicitly allocate NER (to include directly assigned costs) as it avoids the unnecessary step of indexing RCC ratios, which is required to more easily interpret the results of a study that excludes NER.

11.0 MANITOBA HYDRO'S TREATMENT OF DEMAND SIDE MANAGEMENT (DSM) COSTS IS REASONABLE, COST CAUSAL, AND FAIR

[97] The single exception is the Diesel Zone, and this is because the Contribution are directed almost entirely toward the supply of Diesel generation in the four affected communities.

Manitoba Hydro directly assigns DSM costs based on class participation, in other words the class that benefits from the program spending is charged with the costs of that program. Direct assignment has been Manitoba Hydro's preferred approach for DSM in COSS since the mid-nineties, when it was determined that the prior approach of allocating the HPS Conversion program as part of Generation would provide significant early benefits to a single class and distort RCC results.

Manitoba Hydro's Rationale for Direct Assignment of DSM:

- Aligns cost and benefit
- Less distorting to non-participating classes
- Matches timing of short term benefits and costs

1. **Aligns the costs and benefits of the DSM Programs**

Manitoba Hydro believes that where it is reasonable and practical to do so, directly assigning costs to the customers that caused the costs to be incurred results in a superior cost allocation treatment. The costs of DSM programs can be reasonably attributed to participating classes, and as such directly assigning the cost is not only fair, but is the most cost causal approach.

2. **Less distortion for non-participating classes than system benefit approach**

DSM is undertaken to meet Manitoba load reliably and at least cost, and there is a reasonable case that DSM reduces the need for generation, transmission and distribution resources. However, the effect of DSM on class use of these resources is not necessarily aligned with the class share of the total cost of these same resources. Therefore non-participating classes may be negatively impacted by treating as a system resource – i.e. the allocated cost for an individual class may be greater than its eventual benefit on a specific year's basis or even a total basis.[98]

3. **Better matches timing of short term benefits and costs**

As discussed September 7, 2016 at page 57-58 of the Transcript, timing of the offering of DSM programming can favour some classes over others. Some programs can favour a class measurably through reduced usage (and therefore less allocated costs) while other classes are allocated much of the cost of that program, in the short term, if it were treated as a system resource. This can lead to distorted results in any particular COSS which is a one year study. In the long run it is expected that the costs and benefits of DSM would be more evenly distributed among classes, but in the short run such incidence can distort the results of the PCOSS.

[98] Manitoba Hydro Cost of Service Review, September 7, 2016, pg. 57

Intervener Positions

MIPUG supports Manitoba Hydro's continued use of direct assignment for DSM costs, while the Coalition and GSS/GSM recommend allocating the costs as a system benefit. GAC recommends further study to determine the appropriate treatment.

Manitoba Hydro recognizes it is common in the industry to treat DSM costs as a system benefit assigned between multiple functions, which recognizes that DSM reduces the overall cost of the system for domestic customers by deferring generation investment as well as transmission and distribution investment. However, Manitoba Hydro also believes that the potential effects on non-participants need to be considered as well.

Manitoba Hydro's Rationale

- Aligns cost and benefit
- Less distorting to non-participating classes
- Matches timing of short term benefits and costs

System Benefit Rationale

- Substitute for Investment in GT&D

The Coalition proposes treating DSM costs as system resource, with the costs functionalized to GT&D in proportion to the avoided costs used to evaluate DSM programs. In Coalition Rebuttal dated August 5, 2016 (page 4) the Coalition concluded that because the RIM of the 2014/15 DSM programs was equal to 1.0 overall that,

> *"over the long-term, there should be no material concern regarding the impact on non-participating customers"*.

The use of RIM overall to provide guidance on cost allocation may be indicative, it is not conclusive. While overall programs collectively meet a RIM of 1.0 the programs individually may not - nor are the programs evenly distributed among the customer classes[99]. This suggests that one cannot conclude each customer class is also better off. Therefore non-participating classes may be negatively impacted by treating DSM as a system resource.

LEI also proposes a system resource approach, but recommends classifying the costs as entirely Demand related and allocating on a 2CP basis. As the benefits of DSM to Manitoba Hydro are largely related to the Generation[100] function which is notionally classified entirely as Energy, there is no support for the use of a 100% Demand classification for DSM.

GAC recommends further study to compare the effect on classes for direct assignment and allocation as a system benefit in order to choose the appropriate method. Mr. Chernick's proposal was, essentially, to test DSM programs by comparing three scenarios, cost allocation to customers with no DSM, cost allocation with DSM impacts and program cost allocation on the basis recommended by Manitoba Hydro and, third, cost allocation with DSM impacts and program cost allocated on a basis such as that proposed by Mr. Harper and COALITION. The results would be compared to determine if any classes are disadvantaged by either of the approaches to allocating DSM program costs. It is unlikely that Mr. Chernick's proposal can be readily implemented. On the basis of some of his responses to questions, it is reasonable to presume bias against non-participants were Mr. Harper's proposal to be adopted.

First, Mr. Chernick readily agreed that participants' benefits are greater than non-participant benefits[101]:

> MS. ODETTE FERNANDES: *Now, would you agree that participants' benefits are greater than non-participant benefits?*
>
> MR. PAUL CHERNICK: *Are we talking about -- about a participating class versus non-participating classes? Yes.*

Next, he agreed that the smaller the gap between program costs and benefits, the greater the chance that non-participating classes will be disadvantaged:

[99] 2015 Cost of Service Review, September 7, 2016, Transcript pg. 59
[100] Generation benefits provided 6.23¢/kWh of the total 7.67¢/kWh levelized marginal value used in the 2015 DSM Plan (Coalition-MH I 19a)
[101] 2015 Cost of Service Review, September 9, 2016, Transcript pg 812-813

> MS. ODETTE FERNANDES: *And would it be fair to say that the chances of a non-participating class being disadvantaged by the proposal to allocate across the system are greater if the excess of program benefits over costs is relatively small?*
>
> MR. PAUL CHERNICK: *So you're saying if the system benefits are not worth very much more than the program is costing the Utility, it's going -- as it flows through rates. I think that makes sense, yes.*

Mr. Chernick also agreed that at the point in time at which a cost of service study is done, the avoided cost of some program may well be less than the avoided cost used in evaluating the program economics.

> MS. ODETTE FERNANDES: *And would you agree that the cost of service is done for a particular year in which the actual benefit of a particular program may be less than the avoided cost used in -- in evaluating the program economics?*
>
> MR. PAUL CHERNICK: *Yes.*

These responses suggest that, in current circumstances, there is very much a danger that a system benefit approach could disadvantage non-participating classes. Mr. Bowman's comments, which are replicated in the MIPUG Written Submission dated September 21, 2016 (page 7-5) reference a situation in which current year avoided cost could be less than the long term avoided cost used to develop DSM programming.

> *"If you're doing DSM that is being undertaken today, whether the equipment you put in, whether the program runs that long, I think it's very tenuous to say that projects being undertaken today are necessarily affecting in any direct line a decision on whether you build a plant in 2030 -- in the 2030s or 2040."*

Overall, the evidence suggests it would be prudent to assume that the system benefits approach would be unfair to non-participating classes in the absence of strong proof to the contrary.

In its closing Submission on page 28, Coalition offers six reasons why it believes Mr. Harper has made "a compelling case" for a system benefits approach to the allocation of DSM costs. Of the six reasons, Manitoba Hydro accepts four, but notes that they fail to address concerns related to non-participant classes.

> *"DSM plans target savings opportunities that would not otherwise be undertaken are selected on the basis of their overall economics including their ability to contribute to a least-cost plan for Manitoba Hydro*
>
> *Manitoba Hydro has no obligation to provide DSM programs and it elects to do so because it benefits the system overall*
>
> *Customers participate, not as a result of natural market forces, but because they are encouraged to do so*
>
> *Without past DSM investments, there would be shortages now"*

These points are descriptive and relevant to the overall benefits of DSM but do not consider the impact of distribution of those benefits.

The other two points listed on page 31 of Coalition's Closing Submission do address the question of non-participant impacts, but they are far too general to allow the inference that the system benefits will not disadvantage non-participants.

> *"Hydro's DSM portfolio passes the RIM test which means that resource savings from DSM are equal to or exceed the sum of the utilities loss revenues plus any costs for those DSM programs"*

As Manitoba Hydro noted during its direct presentation, a RIM greater than one is of use only in assessing the impacts of an entire portfolio over a very extended period of time. It does not address the current test year perspective of a Cost of Service Study nor does it account for the fact that programs which do not pass the RIM test may be unequally distributed among customer classes.[102]

The last point noted in Coalition's Closing Submission on page 31 is that:

> *"Not all customers within a customer class can actually participate in a classes DSM programs. But they still benefit just as non-participating customers do from other classes"*

However, the question with respect to non-participants is not whether they benefit, but whether the benefit they obtain is sufficient to offset the cost. There is insufficient evidence on

[102] Manitoba Hydro Presentation, 2015 Cost of Service Review, September 7, 2016

the record of this proceeding to demonstrate that non-participants would be held harmless by use of a system benefits approach to DSM allocation and such evidence as has been presented supports a presumption that non-participants would be disadvantaged by changing the basis of allocation from Manitoba Hydro's current approach to the approach recommended by Coalition.

At page 3 of its Reply Submission, the Coalition is stating that to directly assign DSM costs to the classes that make use of the programs is, in effect, not consistent with cost causation.

> *"The claim that customer impacts should be the driving determination in the treatment of DSM is totally at odds with the earlier argument of GAC (page 4-5) that COSS should strictly follow cost causality and that consideration of customer impacts should be left solely to the rate design stage."*

In Manitoba Hydro's view, this depiction is unfair to the position of GAC and misleading to the PUB. One view of cost causation is that because DSM, if done correctly, is a cost effective substitution for Generation, Transmission and Distribution and could reasonably be allocated on that basis. Another view is that DSM programs are offered that allow classes to reduce their usage and save costs and which may, depending on the general availability of programming affect cost assignment to other classes. Both approaches may reasonably reflect cost causation. As noted by Coalition itself on page 2 of their Reply Submission: "In many cases there is more than one way of approaching the question of cost causality." In this case, where two different approaches both have the appearance of reasonability, it is entirely appropriate to consider customer impacts in choosing between them.

It would be quite difficult, in fact, to consider customer impacts related to the allocation of DSM costs at any other stage of the ratemaking process. For example, once costs are allocated, including DSM costs, should an adjustment in class RCC targets be made to reflect the fact that one class may be more disadvantaged than another by the implementation of DSM? Should some adjustment be made in the rate design? If so how do we make an appropriate adjustment if we cannot quantify the degree of advantage or disadvantage? The balance of evidence in this proceeding argues for retention of direct assignment to participating classes which reflects both cost causation and fairness to non-participating classes.

11.1. Curtailable Rate Program (CRP)

In PCOSS14-Amended the annual credit provided to CRP customers is shared among all customer classes as part of the generation pool, while the difference between the annual credit and the CRP annual revenue requirement is directly assigned to the curtailable customers. In the August 12, 2016 written submission Manitoba Hydro accepted MIPUG's recommendation to modify the approach to include the full CRP revenue requirement in the generation pool, as well as MIPUG's rationale for doing so[103].

Intervener Positions

The Coalition does not support these modifications to the treatment of the CRP, stating that even

> *"If one were to accept MH's overall treatment of DSM as being appropriate (which the Coalition/Harper does not) then it is patently unfair that customer classes with CRP load who were credited through the COSS with revenues that exceeded the costs in earlier years should be exempt from impacts of offsetting effects that are now occurring where the credit is less than costs."*[104]

As noted by the Coalition, the GSL 30-100 and >100kV classes did benefit from lower amortization and finance expense as well as higher RCC in the COSS in the past due to this treatment. However, any potential overstatement in RCC has resulted in little, if any, impact to past rate changes and should not be a determinant in the more reasonable treatment going forward.

12.0 OTHER MATTERS

12.1. Further Studies, Investigations, and Updates

As noted on page 15 of Order 26/16, this Cost of Service Methodology Review represents the first review of Manitoba Hydro's cost of service methodology in almost a decade. The PUB noted that its intention was to conduct a comprehensive review and not limit the issues for consideration. As previously discussed in Section 3.2, the results of this process indicates that considerable agreement exists with respect to the most significant aspects of Manitoba Hydro's COS methodology, impacting 80% of its Revenue Requirement. Manitoba Hydro also previously noted that it agrees with the conclusion of MIPUG (September 26, 2016, page 7), although for different reasons, that the results of this process have provided sufficient evidence for the PUB to provide its views and rationale to conclude on Cost of Service Methodology to the extent possible and that any further study on COS methods should be minimized unless the record proves an absolute need.

This is particularly important in the context of achieving cost containment within Manitoba Hydro's operations. As Manitoba Hydro noted in its 2015/16 Annual Report (page 30),

[103] Manitoba Hydro Written Submission, August 12, 2016, pg. 17-18

[104] Coalition Reply Submission, August 19, 2016, pg. 5

Manitoba Hydro has achieved a cumulative reduction of 400 operational positions as of March 31, 2016. These reductions show that Manitoba Hydro is committed to cost containment, and also reflect the realities that there are less resources available to undertake all the additional tasks being requested. These realities must be acknowledged and a practical approach must be undertaken if further studies, investigations and updates are to be accomplished.

In contrast, some Intervener consultants have provided a great deal of commentary on issues they suggest require further study and update or on issues which they deem to be important to investigate consolidated through their final written submissions in August and September. The efforts and costs associated with detailed investigation, data gathering and analysis are significant. The resulting benefits must be weighed carefully against the significant costs associated with performing these studies, whether they be done with internal Manitoba Hydro staff, or by third parties contracted to do such work.

Manitoba Hydro notes that a COSS is complex as it must formulate an allocation of all of the embedded costs reflected in Manitoba Hydro's revenue requirement. Those formulations rely, in some cases, on algorithms driven by data sets involving historic plant data, energy market data or customer weightings, for example. Utilities in general do not update or revise all of these data sets with each subsequent rate filing. While the revenue requirements and load forecasts will be current for each general rate application, it is not necessary to update all subsets within the COSS. It is not generally necessary to undertake the additional effort to update all studies with each filing as the impacts of doing so may not be material to the outcome of the COSS itself.

Nonetheless, Manitoba Hydro has acknowledged in this Final Written Submission as well as those in August, that it intends to explore further certain matters and it intends to review and update some allocators or data which have not been reviewed in a number of years. Subject to Manitoba Hydro's comments, if there are certain issues that the PUB deems of importance to study, Manitoba Hydro requests that the PUB request Manitoba Hydro to file with it a Terms of Reference for review which will outline the scope and breadth of the study to be undertaken, and to assess to availability of required data and information, as well as the costs and forecast time requirements to provide the study to be undertaken.

12.2. COS Model

From the outset of the Cost of Service Methodology Review, interveners expressed an interest in obtaining access to Manitoba Hydro's COSS in live electronic spreadsheet form. In the PUB's letter to Manitoba Hydro dated January 22nd, it stated:

"With respect to the City of Winnipeg's MFR seeking a working electronic model from Manitoba Hydro, the Board directs Manitoba Hydro to work cooperatively with approved Interveners and their consultants to make available a rudimentary working model that does not disclose Manitoba Hydro's proprietary information."

Manitoba Hydro understands that Interveners sought access to the model in order examine the detailed workings of the model and the application of the COSS concepts such that Interveners could satisfy themselves that the model functioned appropriately in calculating the COSS results. As noted by the COW in its Written Submission to the PHC dated February 10, 2016 (on page 4):

"The City's initial position is that these amendments require careful scrutiny both conceptually and through a careful review of the manner in which the concepts have been implemented in MH's COSS model".

On February 12, 2016 the PUB held the first Pre-Hearing Conference in which the issue of provision of the working COSS model was examined. In its letter of February 18, 2016, the PUB directed Manitoba Hydro to make available a rudimentary working COSS model to approved Interveners and the PUB's technical advisors.

In Order 26/16, dated February 26, 2016, the PUB indicated that it considered it important that Interveners be allowed to perform their own scenario runs and directed a process which involved Daymark reviewing a Manitoba Hydro model to ensure it was functional and if determined otherwise, propose changes if necessary.

The PUB further directed, on Page 21 of Order 26/16, that:

"Following this one-week review period, a final version of the model will be made available to all interveners on the express understanding that:

(a) The use of the model is to be limited to this Cost of Service Study Methodology Review; and,

(b) The model must not be disseminated to parties or individuals other than the people working on this Cost of Service Study Methodology Review."

Manitoba Hydro cooperated fully with the PUB and interveners and provided its actual PCOSS14(Amended) model on the requested day of March 2, 2016 and provided a further enhanced version of the PCOSS14(Amended) model on March 11, 2016 in response to requests from Daymark, that reflected minor improvements to facilitate scenario runs for Interveners.

Throughout the COSS review process, significant time and effort was invested by Manitoba Hydro staff, the PUB's advisor Daymark, and consultants Bowman, Chernick, Harper and Todd in the examination and audit of the spreadsheet model. Those consultants undertook a deep and detailed examination of the workings of the COSS model, an effort which extended to auditing individual spreadsheet cells and formulae.

The detailed review, performed by not just one, but five consultants, represents a significant amount of overlapping effort and cost. Manitoba Hydro also notes that generally this detailed review produced minor concerns about the actual function of the model in calculating the COSS outcomes and some only occurring as a result of severing the model from Manitoba Hydro's internal systems.

The PUB, its advisors, Interveners and Intervener consultants have all now had an opportunity to review, test the functionality of, and use Manitoba Hydro's model in order to confirm and verify that Manitoba Hydro's output schedules are correct and in order to satisfy themselves that Manitoba Hydro has a fully functional and appropriate COS model.

In Order 26/16, the PUB concurred that the use of the live COSS model was an exercise to be limited to this particular regulatory proceeding. Manitoba Hydro intends to address its COSS results in future GRA's in the same manner as has been done in previous GRA's, through the filing and submission of the output schedules of its COSS. Manitoba Hydro submits that there is no further need to provide any live COSS models in future GRA's as the integrity of its calculation has been examined in an intense and detailed manner in this current 10 month review process and determined to be sound and reliable.

12.3. Non Disclosure Agreement

In GAC's Final Submission, it was recommended that a standard non-disclosure agreement be developed to allow Interveners easier access to sensitive data relevant to regulatory proceedings. While Manitoba Hydro understands that Interveners may want access to commercially sensitive information, the current regulatory framework in Manitoba must be kept in mind prior to considering this recommendation. *The Public Utilities Board Act*, C.C.S.M. c. P280, at section 15(3) clearly requires that all sittings of the board and the taking of evidence shall be open to the public. In order to ensure that the PUB, Interveners and the public are able to review necessary information in support of submissions and applications, Manitoba Hydro prepares extensive filings which contain detailed information. Parties to PUB proceedings and at times, the general public, have been reviewing and testing Manitoba Hydro's materials successfully over a number of years without access to commercially sensitive information.

Where information cannot be disclosed due to its commercial sensitivity, it is provided in aggregate form. This must continue to be the primary means (almost without exception) of reviewing evidence submitted in support of any submission by Manitoba Hydro before the PUB.

In addition, prior to any discussion regarding the review of commercially sensitive information, a number of issues must be addressed. These include an acknowledgment that there is a distinction between Manitoba Hydro commercially sensitive information and commercially sensitive information of third parties; the development of strict rules and procedures related to any access granted; assurances that not all participants will be granted access as a right (recognizing that some participants may not support the continuing viability of Manitoba Hydro business objectives and could use the information to frustrate business activities, to advance causes in other forums or otherwise further their own interests to the detriment of the Corporation); and meaningful consequences and penalties for any disclosure of commercially sensitive information. Manitoba Hydro views breaches of confidentiality with seriousness and it is not simply a matter of developing a standard non-disclosure agreement as being proposed by GAC.