Manitoba Hydro's Response to the Cost of Service Study Recommendations of Christensen Associates Energy Consulting

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Manitoba Hydro

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MANITOBA HYDRO'S RESPONSE TO THE COST OF SERVICE REVIEW RECOMMENDATIONS

I. INTRODUCTION

This document constitutes Manitoba Hydro's response to the recommendations on Cost of Service methodology prepared for Manitoba Hydro by consultant, Christensen Associates Energy Consulting ("CA") of Madison, Wisconsin. Manitoba Hydro retained CA to perform a review of its Cost of Service Methodologies. Manitoba Hydro undertook the review to confirm that Manitoba Hydro's cost of service methodologies are consistent with best practices and to address a number of issues that arose out of previous PUB proceedings such as Export Revenues and the role of Marginal Costs.

The review also provided an opportunity to evaluate other aspects of the electric Cost of Service Study, and also afforded the opportunity to evaluate the natural gas Cost of Service Study employed by Centra Gas Manitoba Inc. ("Centra"). Centra's current Cost of Service Study was developed and approved in 1996 and has been less controversial than that of Manitoba Hydro; however it was considered to be a timely opportunity to review both methodologies simultaneously.

The goal of CA's review was to examine all relevant aspects of the Corporation's Cost of Service methodologies and, where appropriate, recommend changes. Prior methodological reviews focused on matters pertaining to the classification and allocation methods for Generation and Transmission costs and the treatment of Net Export Revenues ("NER"). Ultimately, apart from a few key Electric Cost of Service issues, most of the topics covered have a relatively minor impact on results of the Cost of Service Study. The key issues for which recommendations were provided include:

1. Export related topics, including the assignment or allocation of costs against export revenues and the allocation of the benefits of NER among domestic revenue classes of service.
2. Functionalization, classification and allocation of the bulk power system, (i.e. Generation and Transmission).
3. The role of marginal cost in the Cost of Service Study.
4. The allocation of capacity related costs in the Natural Gas Cost of Service Study.

Manitoba Hydro has considered the advice and recommendations of CA. While the CA review has included many recommendations, both Manitoba Hydro and CA are aware that not all of CA's comments and recommendations are feasible in Manitoba Hydro's environment.

PCOSS13 reflects many of the recommendations flowing from the Review. Notwithstanding that there are several additional CA recommendations that Manitoba Hydro intends to investigate further as discussed in this Appendix, Manitoba Hydro is of the view that PCOSS13 represents a reasonable depiction of cost by class (and where it departs from such, it is guided by relevant and appropriate policy considerations).

Centra will also file a Cost of Service Study in conjunction with its General Rate Application. Centra is of the view that the CA review is largely supportive of its Cost of Service approach, and will prepare its Cost of Service Study consistent with past practice. CA has made a number of proposals, some of which Centra will look to explore further as discussed in this Appendix.

This document is organized as follows: Section II identifies each of the individual recommendations in the CA report and provides Manitoba Hydro's perspective on the recommendation. In most cases, Manitoba Hydro supports the recommendation, and in those few cases where the Corporation takes a different perspective, a rationale for this position is provided. For the purpose of presentation, the recommendations have been grouped under the following categories: Export Class and treatment of export costs and revenues, bulk power system (Generation and Transmission), Subtransmission & Distribution (plant and services), Area and Roadway Lighting, Centra Cost of Service matters, and Marginal Cost.

Section III of this document provides a table listing each recommendation, and further indicating whether the recommendation is reflected in the current Cost of Service Study, or whether Manitoba Hydro intends to further investigate the recommendation. Likewise, the table identifies generally the direction and magnitude of changes in study results deriving from adoption of Manitoba Hydro's position on each recommendation.

II. MANITOBA HYDRO'S RESPONSE TO THE RECOMMENDATIONS

EXPORT CLASS AND TREATMENT OF COSTS AND REVENUES

Recommendation 1: It is recommended that Manitoba Hydro (MH") maintains the Export Class (Pages 5-7).

MH's Position and Rationale: MH supports this recommendation and the rationale that supports it. Maintaining an Export Class allows the Corporation to assign or allocate appropriate costs to this Class and to recognize Net Export Revenue ("NER").

Recommendation 2: It is recommended that MH implement different cost treatments for firm and opportunity sales with firm sales attracting a share of embedded cost and opportunity sales attracting only variable costs (pages 7-8).

MH's Position and Rationale: MH supports this recommendation and the rationale that supports it.

CA notes "Firm export sales involve planning with a consideration of the use of and investment in generation and transmission plant" (page 6). MH does not build generation plant for export purpose, although it may advance the construction of plants relative to when they would have been constructed to serve domestic load. When considering when to make an export sale, the appropriate test for whether export sales are beneficial is incremental benefits versus incremental costs. The incremental cost of new generation facilities can be significantly higher than the cost of all generation facilities combined in an embedded study, yet the incremental cost of making an export sale out of that new plant may be very small if the plant is not advanced (or is advanced very little) relative to its required in-service for domestic load. For Cost of Service purposes, MH allocates embedded cost to all classes, including firm exports. However, unlike regulated domestic sales, export sales are bought and sold in a competitive market. Because export sales, in the context of Cost of Service, are allocated a share of embedded cost, the Cost of Service Study is not the appropriate vehicle to evaluate the wisdom and efficacy of export sales. Rather, Manitoba Hydro evaluates the forecast incremental cost and revenue associated with each export opportunity before committing to a sale.

Incremental cost of opportunity export sales is simply the variable cost incurred to make the opportunity sale, eg. Water rentals and variable O&M cost in the case of a sale made out of non-firm hydraulic energy. This incremental cost can also be recognized as an embedded cost in a PCOSS, since it is also a current near term forecast cost. Opportunity exports are a byproduct of constructing generation capability to meet domestic load (capacity and energy requirements) in drought conditions or where there exists surplus firm capability not yet required for domestic or firm export. The cost of making the opportunity export is only the water rentals and variable OM&A incurred. Therefore it is proper to recognize only this cost in the PCOSS.

Recommendation 3: With respect to assignment of Affordable Energy Fund ("AEF") costs, it is recommended that these costs should either be directly assigned to the class benefitting from the expenditure or excluded from the PCOSS (pages 9-10, 27).

MH's Position and Rationale: MH agrees with CA's characterization of this cost, i.e., that it benefits certain domestic customer groups and is not correctly assigned or allocated to the Export Class. However, MH does not propose to change the treatment of the AEF within the PCOSS. The AEF is not considered to be a cost related to exports, but to be a policy-related first charge against NER. As provided in the AEF Legislation, the Fund is to support certain energy objectives and not to recover the cost of such programming from the affected customers.

CAs' alternative recommendation is to exclude the expenditure from the PCOSS. If this were to be done, there would have to be a comparable reduction on the revenue side or increase in net income. This however, would be in contravention to the AEF Legislation. The existing treatment of this expenditure has an equivalent effect while acknowledging that this treatment distorts the true margin from electricity sales.

Recommendation 4: It is recommended that the cost of the Uniform Rate Adjustment ("URA") should be assigned to the domestic classes which benefit from this adjustment or, in the alternative, excluded from the Cost of Service Study (pages 9-10, 26).

MH's Position and Rationale: Again, MH agrees that CA has correctly characterized this cost and its causation. However, as in the case of the AEF, MH considers the current treatment to be a policy-related first charge on NER and, hence, is not proposing to change the treatment while acknowledging that this treatment distorts the true margin from electricity sales.

Recommendation 5: With respect to Purchased Power costs, it is recommended that these costs continue to be assigned as charges against exports, as long as imports remain moderate in size compared to exports (page 23).

MH's Position and Rationale: MH agrees with CA's recommendation and the rationale that supports it.

Recommendation 6: It is recommended that wind generated energy should not be directly assigned but should be included in the generation pool for allocation to both domestic and firm export customers (page 23).

MH's Position and Rationale: MH agrees with CA's recommendation and the rationale that supports it.

Recommendation 7: It is recommended that Transmission Service Fees attributable to exports should be assigned directly to exports with any residual fees being allocated among the domestic classes (page 24).

MH's Position and Rationale: MH agrees with CA's recommendation and the rationale that supports it. Currently there are no Transmission Service Fees that are not attributable to exports.

Recommendation 8: With respect to costs related to coal generation (Thermal Unit–Brandon 5), it is recommended that all costs be allocated to domestic rate classes (pages 24-25).

MH's Position and Rationale: MH agrees with CA's recommendation and the rationale that supports it. Brandon #5 is dispatchable only for emergency purposes to serve domestic load or existing firm export contracts which expire by 2015; it cannot be dispatched for any purpose to serve new export sales, whether firm or opportunity sales.

Recommendation 9: If some recognition of natural gas cost responsibility to export is desired regardless of median water flow conditions assumed in the financial forecast and Cost of Service, it is recommended that the cost of natural gas generation be incorporated into the generation pool and allocated to both domestic and firm exports (page 24).

MH's Position and Rationale: MH agrees with CA's recommendation and the rationale that supports it. MH will allocate a share of the cost of natural gas fired generation to exports based on the normal weighted energy allocator.

Recommendation 10: With respect to trading desk costs, CA endorses MH's current approach to allocation between exports and domestic classes, and recommends that MH periodically review the allocator (page 25).

MH's Position and Rationale: MH agrees with CA's recommendation and the rationale that supports it.

Recommendation 11: With respect to MISO and MAPP fees, CA endorses MH's current approach to allocation between exports and domestic classes, and recommends that MH periodically review the allocator (page 25).

MH's Position and Rationale: MH agrees with CA's recommendation and the rationale that supports it.

Recommendation 12: With respect to DSM program costs, it is recommended that these costs be assigned to the domestic rate class that they benefit (via reduced load and allocations), since this treats DSM costs in a manner identical to any other resource (pages 26-27).

MH's Position and Rationale: MH agrees with CA's recommendation and the rationale that supports it. While DSM, by reducing domestic energy and capacity use, frees up resources for sale in the export market, it is not a cost of exports. It is, rather, part of the cost of a least cost package of meeting domestic energy and capacity requirements.

Recommendation 13: With respect to the allocation of NER to benefit domestic rate classes, CA states the following:

"At present, we cannot recommend that MH select one specific allocator. Because the issue is how to deal with substantial margins derived from competitive markets, there is no one cost-based allocation technique that will suffice to provide a stable and “fair” allocation. Therefore we recommend that MH investigate allocators of interest and estimate the ramifications on individual customers before selecting an alternative allocator” (page 11.)

The CA report notes that the current approach, which involves allocation to domestic classes according to the total cost to serve, not including direct assignments, represents a reasonable perspective on fairness, but suggests that MH explore alternative methods including the following:

1) Existing allocators such as those used to assign capital related Generation and Transmission costs;
2) Allocators that recognize the differential risk absorbed by customer classes as NER oscillates over time;
3) Allocators based on unused capacity by each rate class which would be available for export; or
4) Some other ‘fairness” based criterion.

CA further notes that all of these methods, including the current method, face the challenge that allocating net export benefits to domestic classes further reduces retail rates, distorting downward an already low price signal and suggests two potential solutions:

1) Lump sum bill credits, not tied to customer energy use;
2) Assignment of NER to a fund to support future construction or debt buy-back, with rules about transfers in and out of the fund to benefit customers or government (page 11).

MH’s Position and Rationale: MH is of the view that CA is supportive of the current NER treatment that assigns NER on the basis of total cost to serve. As such, MH will continue with its current NER allocation approach. Manitoba Hydro notes that the current approach to allocating net export revenues to domestic classes has achieved a degree of acceptance by the PUB and interested parties.

MH finds CA’s Unused Capacity alternative sufficiently interesting to merit some further consideration as time and resources permit.

BULK POWER SYSTEM (GENERATION AND TRANSMISSION)

Recommendation 14: With respect to Generation classification and allocation, CA recommends that, for the present, MH retains its current methodology (classification as Energy-related, with allocation according to time period weighted short run energy cost (SEP values)). For the longer term, they recommend that MH review potential enhancements and an alternative.

The recommended enhancements are:

1) Incorporating marginal reserves cost
2) Move from 12-period to hourly computation of marginal cost and class load profiles if investigation reveals a higher degree of time variability than the current structure.

As an alternative, CA suggests that MH consider a classification method such as the Equivalent

Peaker Method, whereby either the vintage cost or the marginal cost of a peaker plant such as a gas turbine is compared with the comparable cost for MH's current generation fleet. The ratio of peaker cost per kW to generation fleet cost per kW would represent the portion of generation cost that would be considered demand-related. The remainder of the Generation cost would be considered energy-related (page 12).

> **MH's Position and Rationale:** MH intends to explore the enhancements and alternative suggested by CA, but the time required to do so means that none of them will be reflected in PCOSS13. The current methodology will be employed in PCOSS13.
>
> MH believes that capacity costs are reflected, at least in part, in the differential between on-peak energy values and energy values in the other time periods. However, there is a market for reserves in MISO and it may be appropriate to consider whether or not the values of these reserves, in each time period, could be incorporated into the weights given to energy in each of the time periods.
>
> MH is less convinced that using hourly pricing as weights would offer any significant improvement over the current 12 periods (four seasons, peak/ shoulder/ off-peak) in terms of recognizing energy price variability. The current approach groups similar hours together and offers greater stability to the allocation procedure. MH notes that an earlier move (from a two season, peak/ off-peak to the current 12 period) weighting did not result in a significant change to allocation results. However, as MISO nodal price data and computation techniques are available, MH will explore the impact of a greater degree of disaggregation on the allocation of generation cost over the next year or so.
>
> Similarly, MH is not convinced that the Equivalent Peaker methodology would be an improvement over the current method, but will also explore its possible impacts. MH notes that, based on current forecast construction costs, the ratio of capital cost per kW of a gas turbine to a hydraulic plant is approximately 15% so it would be expected that a demand energy split based on this methodology would be in the order of 15:85. Further, it is likely that appropriate use of the methodology could require time period energy weightings which differ from the current approach.

Recommendation 15: With respect to the functionalization and allocation of HVDC Bipole facilities, CA recommends that MH continue to treat these facilities as Generation (page 15).

> **MH's Position and Rationale:** MH supports the recommendation and the rationale that supports it.

Recommendation 16: With respect to the functionalization and allocation of HVDC Bipole facilities, CA also recommends that MH investigate its cost allocation approach for the Dorsey Station. It is CA's view that "a share of the costs attributable to the DC facilities situated at the Dorsey station should thus be assigned to the Generation function. The cost share attributable to Transmission, in isolation of DC facilities can only be assessed objectively with simulation studies" (page 15).

> **MH's position and rationale:** Manitoba Hydro remains resolved that it has properly allocated costs for the Bipole lines and Converter Stations, but will implement the recommendation to confirm this allocation through a counterfactual design simulation study.

However, the time required to do so means it will not be reflected in PCOSS13.

CA notes the cost share attributable to transmission, in isolation of HVDC facilities can only be assessed objectively with simulation studies " (page 15). In the absence of a design simulation study, MH believes that the current practice of including Dorsey station in the Transmission function in its entirety is well founded due to the considerable improvement in the technical capability of the meshed network provided by the station, and the considerable investment that would be required to design an alternative transmission system to the same level of domestic reliability and availability.

Manitoba Hydro implemented HVDC technology to bring the power from the Nelson River 900 km south to Winnipeg because of economic considerations (lower losses and lower capital investment), and because of the inherent fast converter controls of an HVDC System to provide AC transmission network stability. Because of Manitoba's choice of the HVDC technology, Manitoba Hydro was also able to multiply the cost benefit saving on future networked expansion to the U.S. by eliminating the expensive requirement for redundant tie-lines, for example, through the alternative use of inherently fast HVDC converter controls. Damping control was another requirement. AC transmission lines with long distances between areas result in natural oscillations which limit the power that can be transmitted on the transmission system. The HVDC scheme provides an advantage in that supplementary controls can use the fast HVDC converter controls to provide damping of these natural oscillations which when damped, allow for higher power transfers.

Therefore the ability to control the firing angle and damping through the HVDC terminating facilities and controls provides a large change in the technical capability of the meshed network outside of the tie to generation. Without these facilities and controls, Manitoba Hydro would have several more expensive investment requirements to ensure the same level of domestic reliability and transfer capability to/from the U.S. For example, one option may have been to build a redundant tie-line to the U.S., at considerable cost and risk. As well, had Manitoba Hydro implemented AC facilities from the north, the transmission infrastructure would have been significant and much more costly than HVDC.

Recommendation 17: With respect to transmission service from radial taps, it is recommended that MH either assign radial cost to those customers requiring the radials or have the radial cost averaged into high voltage transmission cost instead of the current method of averaging these costs into the sub transmission cost (page 16).

MH's Position and Rationale: MH supports this recommendation. Since PCOSS02 the facilities included in the transmission function have been limited to those eligible for inclusion in MH's Open Access Transmission Tariff. High voltage transmission facilities that are not eligible, such as dedicated radials serving the GSL>100 kV subclass, were included in the subtransmission function. Since this subclass is not charged a share of subtransmission costs, there has been a slight understatement in the cost to serve the GSL

>100 kV subclass. Direct assignment of the cost to the subclass is the preferred treatment as it better reflects cost causation.

A further expansion of concept will include the addition of a Radial Transmission sub-function in the next PCOSS to capture the costs of non-dedicated Transmission assets currently included in the subtransmission costs. The current treatment results in a minor understatement in the cost to serve the GSL >100kV subclass that MH will look to correct in the next Cost of Service Study.

SUBTRANSMISSION AND DISTRIBUTION (PLANT AND SERVICES)

Recommendation 18: With respect to classification and allocation of Sub Transmission, it is recommended that "MH informally review whether the criteria stated above for selecting a CP-related allocator are satisfied. If a CP approach appears to be advisable based on informal review, MH can undertake a formal study. We cannot recommend a change prior to the results of an initial inquiry." (page 16).

MH's Position and Rationale: MH intends to explore the recommendation suggested by CA, but the time required to do so means that it will not be reflected in PCOSS13. The current Non-Coincident Peak ("NCP") allocator will be employed in PCOSS13.

Recommendation 19: With respect to the classification of distribution plant, it is recommended that MH continue to classify its distribution plant costs via a combination of demand- and customer-related factors. CA recommends that MH not consider energy as a basis for the allocation of distribution plant costs. Also, that MH should consider updating the study that splits distribution cost into demand- and customer- related components MH should also review its classification of line transformers as solely demand-related. However, the Company's current approach for transformers resides well within the bounds of industry practice. (page 18).

MH's Position and Rationale: MH will update the split of distribution cost into demand- and customer-related components as resources allow. MH currently classifies distribution pole and wires as 60% Demand and 40% Customer related, which is comparable to that seen at other utilities. The current classification of line transformers as demand-related is not uncommon in the industry. Conducting the studies as recommended requires a significant volume of data, effort and cost and may not yield results materially different than the current ratio.

Recommendation 20: With respect to the allocation of Distribution plant costs, it is recommended that MH retain its current method of allocating these costs, as it is in line with industry practice. CA also recommends, where cost effective, that MH update its supporting studies. We do not recommend investigation at present of alternative allocations, based on the relative cost and value of such research (page 19).

MH's Position and Rationale: MH will update the supporting studies used to determine the class-NCP allocator where cost effective and as resources allow. Updates to Area and Roadway Lighting load data is discussed elsewhere in this document. Updates to Flat Rate

Water Heating (FRWH) and Seasonal data solely for use in the PCOSS cannot be justified on a cost-benefit basis given the small portion of load they represent in their respective classes.

As a result of other work underway, load data specific to FRWH will be available in the fall of 2013. MH will reflect the updated FRWH data in its PCOSS at that time.

Recommendation 21: With respect to service voltage, it is recommended that “MH consider accounting in its COS methods for the fact that these customers do not require primary lines investment to serve them.

A. Create a separate demand allocator for customers served from substations. This allocator would not allocate distribution lines costs to them when lines are not necessary for their service” (page 20).

MH’s Position and Rationale: MH accepts the recommendation that GSL 0-30 kV customers served from dedicated MH owned substations should be excluded from the allocation of distribution line costs. The point of delivery for these customers is directly off the low side of the distribution substation, and as such they do not require the installation of distribution lines. The current treatment results in a slight overstatement in the cost to serve the GSL 0-30 kV subclass that will be addressed in the next study.

MH does not accept that the treatment be expanded to other customers based on their proximity to substations. There is a key distinction between customers who make no use of a facility versus those who use a small portion of it. Customers served directly from a dedicated substation can be readily and objectively identified. Extending treatment based on customer location not only requires a subjective decision on the number of allowable spans to define qualifying customers, but then is faced with the practicality issues in identifying customers that meet this criteria. As acknowledged by CA (page 20), the choice of the number of allowable spans creates difficulty as the cut off will be contested wherever it is drawn, and cannot avoid being criticized as an arbitrary distinction.

B. It is recommended that MH consider separating lines into two service levels: primary and secondary, each with separate allocators (page 20).

MH’s Position and Rationale: MH accepts the recommendation and rationale that supports it:

At page 20, CA states “customers taking service at primary voltage do not require equipment at secondary voltage. This should be taken into account in the COS if possible.”

Customers in the General Service Large 0-30kV class are responsible for providing their own transformers, and therefore do not use MH’s secondary distribution facilities. Accounting records do not fully segregate these costs and to accommodate this change, MH will rely upon a 70/30 split of primary and secondary voltage. This ratio the best available estimate of the relative cost portions, and will be used in PCOSS13. Based on this estimate the class’s customer count and NCP demand allocators for distribution poles and wires have been reduced by 30% so effectively the class is not allocated any costs of secondary voltage distribution.

MH will examine other methods of estimating the portion of costs related to secondary distribution, and if feasible, update the adjustment in a future Cost of Service Study.

C. It is recommended that MH consider the separation of cost into single- and three-phase for facilities such as line transformers (page 20).

MH's Position and Rationale: MH accepts that further separation of distribution costs between single and three phase may allow for some improvements in allocation that better reflect cost causation. Given that accounting records do not allow costs to be segregated in this manner and the minimal improvement expected, MH does not intend on pursing this further.

AREA AND ROADWAY LIGHTING ("ARL")

Recommendation 22: With respect to Collection and Billings allocation to ARL, CA states, "The method used by MH to create the ARL contribution to allocators C11 and C12 appears to be appropriate, although the studies that support those contributions are somewhat dated. We recommend that MH update its estimated number of fixtures per customer. We recommend that MH consider removing ARL from the allocator for Collections, because it is not likely that ARL presents a collections issue" (page 21).

MH's Position and Rationale: Given the age of the study supporting the weightings, the fact there is no collection issue for the ARL class, and the negligible impact the cost allocation has on class RCCs, MH accepts the recommendation to remove ARL from the allocator for Collections. Additionally, MH will update the Billing and Collections allocators in the next GRA, should the updated finding warrant it.

Recommendation 23: With respect to the allocation of Distribution poles & wires, CA states, "to determine ARL's customer weight, MH divides lighting into two categories: less than and greater than 250 watts. MH assumes that customers with lights of less than 250 watts have ten fixtures per customer and customers with lights of greater than 250 watts have six fixtures per customer. MH periodically updates lamp counts, but may need to review its demarcation boundary on occasion. We recommend that MH review whether this division into less than 250 watts and greater than 250 watts is still appropriate" (page 22).

MH's Position and Rationale: MH agrees with the recommendation and the rationale that supports it. The customer count used for the class is based on the estimated number of connections that street lights make into the distribution system if connected through relays. It is appropriate to confirm that both the wattage threshold and the number of installed lamps per relay reflect the technologies and practices currently used for lighting installations, which may have changed since the factors were developed.

Recommendation 24: With respect to the allocation of Distribution poles & wires, CA further recommends that "MH review whether the manner in which ARL assets are connected to the underground system differ from the way that they are connected to the overhead system. This

review may reveal whether there are some common secondary costs used by ARL fixtures that should be allocated to ARL in addition to the current cost assignment at secondary to ARL" (page 22).

MH's Position and Rationale: MH has adopted the convention that 30% of poles and wires cost are related to secondary distribution and have excluded ARL from the allocation of the customer portion of the common secondary distribution system. MH believes that this convention reasonably depicts ARL distribution cost causation but intends to investigate its reasonableness further and review the practice at other utilities.

Recommendation 25: With respect to the allocation of Marketing R&D, it is recommended that "MH not allocate any Marketing R&D costs to ARL. If MH retains this allocation, the Company should update the estimated relationship between number of fixtures and number of customers" (page 22).

MH's Position and Rationale: MH supports this recommendation. Marketing R&D includes costs related to creating marketing plans, customer surveys, maintaining customer coding databases, and enhancing business development in the province. MH agrees it is not appropriate to allocate a share of the costs to the ARL class given the nature of these activities.

Recommendation 26: With respect to the Load Research for ARL, it is recommended that, "MH update its sampling to support ARL. This updating includes the seasonal CP LF, the annual CP LF, and the kWh sample by month and time period. We also recommend that MH consider a multiple sample year approach to minimize the chances of aberrant results in a single year resulting in inappropriate cost allocation for a number of years." (page 22).

MH's Position and Rationale: MH supports this recommendation. The load shape for the ARL class is directly related to daylight hours and is therefore highly consistent from year to year. However, since there may be slight variation in usage due to heavily overcast days, faulty controllers and failed lamps a periodic verification of the assumed load for the class by actual load data is warranted. The updated Load Research sample will also enable confirmation of the assumed ballast losses used to calculate energy consumption for the class, by comparing nominal to actual demand for each type of fixture.

CENTRA COST OF SERVICE MATTERS

Recommendation 27: With respect to the Peak and Average demand allocator, CA supports the continuance of this demand allocator for Transmission and Distribution. CA goes on to state that Centra consider the investigation of a peak-customer allocator alternative (page 30).

Centra's Position and Rationale: Centra is supportive of the continuance of a peak and average approach for the allocation of demand related costs as endorsed by the CA. Centra is of the view that the peak and average methodology has served the utility well, is recognized in industry as a well founded allocation approach that gives a balanced weight to the objectives of economic efficiency and fairness in that it gives recognition to the use of the system, is simple, and provides an objective basis for the determination of rates.

Centra accepts CA's perspective that peak demand and length of pipe are likely key drivers of cost. However, Centra is of the view that:

1. Given the distribution of customers in Manitoba, it is not apparent that customer count is a reasonable proxy for distance; and
2. With respect to Distribution Plant, Customer numbers are considered at the Classification Phase (through its diameter-length study).

For these reasons as well as that this approach not employed elsewhere, Centra does not intend to pursue further study of the use of customer as a proxy for distance.

Recommendation 28: With respect to combination allocator weights, CA recommends that Centra explore whether load factor conforms adequately to the impacts of the underlying two main cost drivers (peak day, distance) on facility costs. As a consequence CA recommends that Centra consider conducting a cross-sectional statistical analysis of costs and cost drivers, reflected in historical work order records (page 31).

Centra's Position and Rationale: Centra is supportive of CA's recommendation to review load factor used to weight peak and average. Using load factor as the basis to weight peak and average appears to be consistent with an approach stated by the National Association of Regulatory Utility Commissioners but its origins in Manitoba are unknown and likely are due to be reviewed. With respect to the recommended cross-sectional statistical analysis, Centra does not propose to carry out this work as it represents significant effort for a minor refinement.

Recommendation 29: With respect to seasonal rates, CA recommends Centra explore seasonal differentiation of tariff prices. This exploration should consider the cost of implementation, since seasonal prices involves a major change in Centra's cost allocation framework and tariff design (page 31).

Centra's Position and Rationale: Centra accepts that it may be more theoretically superior, from an economic perspective, to offer a seasonal rate that encourages off-season consumption. Seasonal rates can be attractive for utilities who construct facilities to meet peak demands (often with capacity going unused during off-peak periods). Off-season load would improve Centra's annual load factor which has benefits for purchased gas and pipeline contracts and for the use of Centra's fixed investment in its pipeline facilities. However, Centra is of the view that a broader public policy consideration is also at issue in Manitoba in that seasonal rates tend to adversely affect customers who are captive space heating customers. Additionally, seasonal rates would add further complexity to Centra's bill and may also increase its revenue stability risk if there is a large difference between forecast peak and actual peak usage. It is also recognized that the three-part rate structure employed for large volume customers already have a strong seasonal element. Centra finds that the disbenefits of seasonal rates outweigh the benefits and does not endorse CA's recommendation to create seasonal rates.

Recommendation 30: With respect to heating value deferral, CA recommends that Centra should include only customers with monthly bills that are determined according to energy sales volumes in the disposition of differentials attributable to heating value (page 31).

Centra's Position and Rationale: Centra accepts CA's recommendation with respect to the allocation of the disposition of the heating value deferral. Centra currently assigns heating value residuals to all customer classes on the basis of each class' contribution to total annual throughput. Heating value residuals accumulate if the heating value of gas delivered is greater or less than forecast resulting in customers consuming volumes that are greater or less than forecast. The deferral has been put in place to track the impact to gross margin that occurs when the energy content of gas is greater to or less than forecast. For most customer classes, gross margin is largely collected through volumetric rates. The Special Contract Class rate structure is predominantly fixed (with only unaccounted for gas collected volumetrically), and should not, therefore, participate in the disposition of the heating value deferral.

Recommendation 31: With respect to offering Transportation Service ("T-Service") to Large General Service ("LGS") customers, CA recommends that Centra consider retaining its T-service within its tariff package, providing that offering that service does not prove unduly burdensome to Centra. Preserving the T-service option preserves optionality, which is usually a good thing unless it is costly to do so (page 5).

Centra's Position and Rationale: In Order 65/11, the PUB approved Centra's request to implement a minimum daily nomination threshold because it was difficult to balance the daily load requirements of low volume gas users. As a result of this change, LGS customers are no longer eligible for T-service. Since the issuance of Order 65/11, no changes in operations have occurred and no LGS customer has expressed an interest in this service offering. Centra does not intend on re-implementing this service option at this time.

Recommendation 32: With respect to the Cooperative ("Co-Op") Class, CA recommends that Centra consider closing the Co-op service option due to the lack of use and low likelihood of increased participation (page 5).

Centra's Position and Rationale: Centra accepts CA's recommendation. Centra implemented a Co-op Class in 2003 that was created specifically for the North Cypress Energy Co-op (NCEC) with eligibility criteria such that all future Co-op entities served directly from Centra's Transmission facilities (among other criteria as set out in Centra's Terms and Conditions of Service) are eligible for the service option. Since that time, NCEC has dissolved, Centra acquired its assets and no customer has been eligible or expressed an interest for the service option. It is Centra's view that it is appropriate to close the Co-op Class service option.

Recommendation 33: With respect to Revenue to Cost ("RCC") ratios, CA suggests that "The COS methodology of Centra accommodate a range of acceptable RCC ratios, in a manner similar to that of MH's approach for electricity services" (page 32).

Centra's Position and Rationale: Centra is open to CA's recommendation recognizing that setting rates at unity broadly achieves the goal of collecting an appropriate share of the costs incurred by the utility to provide service to customer classes. However, a range approach is often preferable to the implementation of a specific RCC ratio to recognize the degree of judgment in conducting cost allocation studies regardless of the demand allocation method used.

Centra has previously set rates around a 97:103 range in the early and mid 1990's. While Centra views that it should in most cases strive to align rate levels to costs, it also views that under limited circumstances, deviating from unity may be a reasonable approach to provide rate stability. Proposed rate changes should consider the ability of consumers to respond to the change and to avoid rate shock. It may be worthwhile to consider RCC ratios other than unity in circumstances where large increases to a class (or classes) may create hardship for consumers. Such circumstances could include dramatic commodity price spikes that occur from time to time or phasing in methodology changes to cost allocation.

MARGINAL COST

Recommendation 34: With respect to the use of Marginal Cost information in the embedded Cost Study, CA does not recommend the replacement of traditional embedded cost-based methods with marginal cost-based methods. Marginal cost-based allocation studies will provide a useful guide to pricing, while still under the constraints of overall revenue recovery as defined by financial costs. Additionally, marginal cost-based allocation may provide guidance in determining target class RCCs and the acceptable range for RCCs. For instance, a particular rate class with marginal cost distinctly different from other rate classes' marginal cost and from its embedded cost might warrant variance from the traditional RCC target. Some reasons for extraordinary marginal cost variation for a specific rate class could be that rate class's load shape or additional cost of certain functions in the system upon which this rate class depends heavily (page 36).

MH's Position and Rationale: MH accepts CA's recommendations with respect to the use of marginal cost information.

Recommendation 35: With respect to the development of Marginal Cost – Electric operations, CA recommends that MH implements a marginal cost-based allocation in parallel with its embedded approach. CA also had suggested additions or modifications to MH's existing marginal costing. These included:

1) Include hourly marginal line losses covering conductors and transformers;
2) Include other cost dimensions within all-in marginal costs, potentially including: working capital, A&G General plant; fixed O&M; property taxes; insurance and other taxes, to the degree that such cost dimensions are on the margin.
3) Consider applying a private cost of capital metric
4) Consider use of an economic carrying charge approach for determining the temporal pattern of annual capital charges (pages 36-37).

MH's Position and Rationale: MH currently prepares marginal cost estimates for Generation Capacity and Energy seasonally differentiated for winter and summer. MH also prepares estimates of the marginal capital cost of new Transmission and Distribution. These estimates are intended to be generic estimates for serving customers within the province of Manitoba.

In 2008 and again in 2010 MH filed estimates of class marginal cost and revenue with the Public Utilities Board. These estimates relied on the marginal cost studies of Generation, Transmission and Distribution noted in the paragraph above. To these were added operating costs of transmission and generation as well as costs associated with customer service, all these from the current Cost of Service Study. Generation marginal cost is based on opportunity cost values, so it is not necessary to add current operating costs. Unit marginal cost is measured at customer meter so it includes average line losses. However, no estimates of marginal line losses are available.

The PUB has indicated that MH's earlier filed depiction of marginal cost of Generation, Transmission, and Distribution requires "refinement" and that MH should specify how marginal cost results could be used in an embedded cost study (Directive 20, Order 150/08). However, the PUB has yet to indicate specifically the types of refinement it is seeking nor provided any guidance as to how marginal cost estimates should be incorporated into embedded cost studies.

MH is prepared to file marginal cost estimates by class, derived from existing studies and data in the same manner as previous estimates filed with the PUB. However, MH will not undertake any enhancements or modifications to its processes for estimating marginal cost, pending further review by the PUB. MH will continue to use marginal cost information to classify and allocate generation costs but does not propose to introduce marginal cost information into classification and allocation of other functions. MH agrees that marginal cost information can inform interpretation of the Cost of Service Study results, i.e. Zone of Reasonableness for RCC's.

Recommendation 36: With respect to Marginal Cost – Gas operations, CA recommends that Centra implement a marginal cost-based allocation in parallel with its embedded approach. CA also suggested that the marginal cost of natural gas services be further refined as follows:

1) Development of transmission and distribution cost metrics;
2) Consider applying a private cost of capital metric; and
3) Consider use of an economic carrying charge approach for determining the temporal pattern of annual capital charges (page 37).

Centra's Position and Rationale: Centra is not convinced that preparing a marginal cost-based allocation in parallel with its embedded approach offers any significant improvement over its existing embedded cost approach. A marginal cost-based allocation presents a number of challenges to COS. As CA states, the marginal cost-based allocation for Centra would not likely result in a significantly different outcome than obtained with a traditional embedded cost-based approach. This is driven from the fact that commodity (primary and supplemental gas) is already priced at the margin. Even at today's natural gas prices,

commodity costs represent approximately 40% of Centra's total revenue requirement making the impact of a marginal cost-based allocation less beneficial. For other upstream costs (transportation and storage) Centra is a price taker. While the prices don't reflect marginal cost to the seller, they are Centra's marginal cost. Secondly, it may be difficult to agree on a definition of marginal cost for cost allocation purposes.

Marginal cost information is simply not as valuable to Centra as it is to MH electric operations. It is not well known to the natural gas utility industry and the current embedded approach has served the utility well. For these reasons, Centra is not prepared to consider further a marginal cost-based allocation.

III. ACTIONS FLOWING FROM RECOMMENDATIONS

	#	Recommendation	Reference	Timing	Steps to Operationalize	Impact on Costs relative to PCOSS11
EXPORT CLASS AND TREATMENT OF COSTS AND REVENUES	**1**	Maintain Export Class	Pages 5-7	PCOSS13 unchanged.	None required.	None. Treatment consistent with current practice.
	2	Implement different cost treatments for firm and opportunity sales with firm sales attracting a share of embedded cost and opportunity sales attracting only variable costs.	Pages 7-8	Reflected in PCOSS13.	Already undertaken.	Currently all exports, including opportunity exports not deemed served by power purchases, are assigned a share of all embedded Generation and Transmission cost. Adoption of this recommendation will reduce the share of generation and transmission costs borne by exports and increase the share borne by domestic classes. Since less cost is allocated to the Export Class in PCOSS13 (than PCOSS11), there is a larger amount of net export revenue to be shared among the domestic classes. Consequently, the RCC of classes served from the Distribution system will increase and the RCC of classes served upstream of the Distribution system will tend to decrease. The specific class impacts are depicted in PCOSS13 in Schedule B7.
	3	AEF costs should either be directly assigned to the class benefitting from the expenditure or excluded from the PCOSS.	Pages 9-10, 27	PCOSS13 unchanged.	None required.	None. Treatment consistent with current practice.
	4	The cost of the URA should be assigned to the domestic classes which benefit or excluded from COS	Pages 9-10, 26	PCOSS13 unchanged.	None required.	None. Treatment consistent with current practice.
	5	Continue to assign Purchased Power costs as charges against exports, as long as imports remain moderate in size compared to exports.	Page 23	PCOSS13 unchanged.	None required.	None. Treatment consistent with current practice.
	6	Wind generated energy should not be directly assigned but should be included in the generation pool for allocation to both domestic and firm export customers.	Page 23	Reflected in PCOSS13.	Already undertaken.	The cost of purchased wind generated energy is currently directly assigned to the Export class. Inclusion of the cost of wind in the generation pool will reduce slightly the share of generation costs borne by

	#	Recommendation	Reference	Timing	Steps to Operationalize	Impact on Costs relative to PCOSS11
						exports and increase slightly the share borne by domestic classes. Since slightly less cost is allocated to the Export Class in PCOSS13 (than PCOSS11), there is a larger amount of net export revenue to be shared among the domestic classes. Consequently, the adoption of this recommendation will tend to increase the RCC of classes served from the Distribution system and reduce the RCC of classes served upstream of the Distribution system. The specific class impacts are depicted in PCOSS13 in Schedule B7.
	7	Transmission Service Fees attributable to exports should be assigned directly to exports with any residual fees being allocated among the domestic classes	Page 24	PCOSS13 unchanged.	None at this time.	None at this time.
	8	Allocate coal generation costs to domestic rate classes	Pages 24-25	PCOSS13 unchanged.	None.	None. Treatment consistent with current practice.
	9	Allocate gas-fired thermal plants to domestic and firm exports through the generation pool.	Page 24	Reflected in PCOSS13.	Already undertaken.	The cost of gas-fired thermal plants was previously entirely assigned to the domestic classes. Including firm exports in the allocation of the costs of natural gas fired generation will increase slightly the share of generation costs borne by exports and decrease slightly the share borne by domestic classes. The RCC of classes served from the Distribution system will tend to decrease and the RCC of classes served upstream of the Distribution system will tend to increase. The specific class impacts are depicted in PCOSS13 in Schedule B7.
	10 **11**	Trading desk costs and MISO and MAPP fees be allocated between exports and domestic classes, and periodically review the allocator	Page 25	PCOSS13 unchanged.	None at this time.	None. Treatment consistent with current practice.

	#	Recommendation	Reference	Timing	Steps to Operationalize	Impact on Costs relative to PCOSS11
	12	DSM program costs should be assigned to the domestic rate class that benefits (via reduced loads and allocations), since this treats DSM costs in a manner identical to any other resource	Pages 26-27	PCOSS13 unchanged.	None.	None. Treatment consistent with current practice.
	13	MH to investigate NER allocators as discussed and estimate the ramifications on individual customers before selecting an alternative allocator.	Page 11	PCOSS13 unchanged.	Consider further "unused capacity" options	None at this time. Impacts could be material.
BULK POWER SYSTEM	**14**	MH to consider incorporating marginal reserves costs, moving to hourly computation of marginal cost and hourly load profiles by class and/or equivalent peaker allocation	Page 12	As resources allow.	MH to consider further incorporating marginal reserve costs.	Generation costs are currently allocated on the basis of weighted energy, where class energy use is weighted by the relative value of the energy over twelve time-periods (On/Off/Shoulder periods in each of the four seasons). Impact not expected to be material.
	15	MH continue to treat the bipole facilities as generation.	Page 15	Reflected in PCOSS13.	None required.	None. Treatment consistent with current practice
	16	A share of the costs attributable to the Dorsey station DC facilities should be assigned to the generation function to be assessed with simulation studies	Page 15	As resources allow.	Conduct simulation study.	None. Treatment consistent with current practice.
	17	MH either assign radial cost to those customers requiring the radials or have the radial cost averaged into high voltage transmission cost.	Page 16	PCOSS13 reflects the direct assignment of dedicated radial taps. Add a Radial Transmission sub-function at the next GRA.	Add a Radial Transmission sub-function.	The cost of dedicated transmission voltage radial taps is currently allocated as part of Subtransmission costs. Direct assignment of the radial taps results in a slight decrease in the RCC of the GSL >100kV subclass. The specific class impacts are depicted in PCOSS13 Schedule B7.

	#	Recommendation	Reference	Timing	Steps to Operationalize	Impact on Costs relative to PCOSS11
SUBTRANSMISSION & DISTRIBUTION	**18**	MH consider a CP allocator for sub transmission costs	Page 16	As resources allow.	Confirm whether investment is primarily based on CP or NCP, and determine the correlation between loads on sub transmission lines and system peak loads.	Subtransmission costs are currently allocated on the basis of class-NCP demand. The impact would be minimal for most classes. An ARL RCC increase of less than 2% is expected due to the low coincidence factor for the class.
	19	MH should continue to classify its distribution plant costs via a combination of demand- and customer-related factors. MH to consider updating splits MH should review its classification of line transformers.	Page 18	As resources allow.	Determine whether the zero-intercept or minimum-size-of-facilities method is more appropriate and technically feasible.	Pole and wire costs are currently classified as 60% demand and 40% customer related, while line transformers are classified as 100% demand related. The overall impact is expected to be minimal. Increasing the demand share will tend to increase the RCC of classes with a comparatively smaller average demand per customer. An increase in the customer share would increase the RCC of classes with higher average demand.
	20	MH update its distribution plant supporting studies related to determining class NCP.	Page 19	PCOSS13 unchanged. Update to FRWH load considered once data is available in late 2013.	FRWH load data collection underway.	The current Load Research study sample does not include the ARL, Seasonal or Flat Rate Water Heating classes. The class impact will depend on the results of the updated studies, but the impact of updating the FRWH load data is expected to be negligible given the size of the sub class.
	21	**A.** Create a demand allocator for customers served from substations.	Page 20	Next GRA.	Exclude NCP demand from the allocator and remove the unweighted customer count used to allocate the customer portion of the costs.	GSL 0-30kV customers served from dedicated substations are currently allocated distribution pole and wire costs on the same basis as all other customers in the class. Adjusting for customers served from dedicated substations will slightly increase the RCC of the GSL 0-30kV class.
		B. Consider separating lines into two service levels: primary and secondary		Reflected in PCOSS13.	Adjustment made to allocator for GSL 0-30kV to exclude from the allocation of secondary voltage distribution.	GSL 0-30kV customers are currently allocated distribution pole and wire costs that include the cost of secondary distribution facilities. The reduction in allocated distribution costs for the class

	#	Recommendation	Reference	Timing	Steps to Operationalize	Impact on Costs relative to PCOSS11
						will result in an increase in class RCC, with a minimal decrease in RCC for other classes The specific class impacts are depicted in PCOSS13 in Schedule B7.
		C. Consider a further separation of cost into single- and three-phase for facilities such as line transformers.		PCOSS13 unchanged.	Cost data not available for segregation.	None.
AREA & ROADWAY LIGHTING	**22**	Update estimated number of fixtures per customer. MH consider removing ARL from the allocator for collections.	Page 21	PCOSS13 removes ARL from collections allocator. Update weighting factors at the next GRA.	Prepare a study incorporating management estimates of the relative effort to serve each customer class for all costs allocated in the Collections and Billings cost categories.	The removal of ARL from the Collections allocator has increased the class RCC approximately one tenth of a percent. The cost categories represent less than three percent of the total costs in the PCOSS, it is not expected that a change in weighting factors would have a significant impact on class RCC.
	23	MH review whether the division for ARL into less than 250 watts and greater than 250 watts is still appropriate.	Page 22	Next GRA.	Review the manner that lighting fixtures are currently installed and connected.	While the directional impact from a possible change in the ratio of fixtures to connection cannot be known in advance, the RCC impact is not likely to be significant unless the ratio changes dramatically.
	24	MH to review whether there are some common secondary costs used by ARL fixtures that should be allocated to ARL in addition to the current cost assignment at secondary to ARL.	Page 22	PCOSS13 unchanged.	MH will investigate further and will look at practices at other utilities.	None.
	25	MH not allocate any Marketing R&D costs to ARL.	Page 22	Reflected in PCOSS13.	Already undertaken.	The removal of ARL from the Marketing R&D allocator increases the class RCC approximately one tenth of one percent.
	26	Update load research sampling to support ARL. MH to consider a multiple sample year approach to minimize the chances of aberrant results in a single year.	Page 22	The first fiscal year data is expected for 2013/14.	The load research meters are expected to be installed winter of 2012.	The factors used to calculate demand allocators for the class is currently based on single-year load research samples. The RCC impact is expected to be minimal due to the highly predictable load profile for the ARL class.

	#	Recommendation	Reference	Timing	Steps to Operationalize	Impact on Costs relative to PCOSS11
CENTRA COST OF SERVICE MATTERS	**27**	CA supports the continuance of the Peak and Average demand allocator for transmission and distribution. Centra may consider the investigation of a peak-customer allocator alternative	Page 30	No change.	None.	None.
	28	Explore whether load factor conforms adequately to the impacts facility costs. Consider conducting a cross-sectional statistical analysis of costs and cost drivers, reflected in historical work order records	Page 31	No changes in current COS. Centra to evaluate the potential update of load factor used to weight peak and average over the next year.	Consider the weightings of peak and average, on the basis its cost records as well those in other jurisdictions.	The impacts are indeterminate at this time.
	29	Explore seasonal differentiation of tariff prices.	Page 31	No change.	None	None.
	30	Heating Value Deferral--Centra should include only customers with monthly bills that are determined according to volumes in the disposition of differentials.	Page 31	Next GRA.	Create a new allocator. Consider annual update of energy content of natural gas.	No impact in this COS study. The impact of the change is immaterial for most customer classes, but is expected to be of greater impact to the Special Contract Class.
	31	Consider retaining LGS T-service	Page 5	No change.	None.	None.
	32	Centra consider closing the cooperative service option	Page 5	Next GRA.	Remove service offering	Negligible impacts are expected.
	33	Accommodate a range of acceptable RCC ratios, in a manner similar to that of MH's electric approach	Page 32	No change at this time. That could change in the future as circumstances arise.	None at this time.	Indeterminate at this time.

	#	Recommendation	Reference	Timing	Steps to Operationalize	Impact on Costs relative to PCOSS11
MARGINAL COST	**34**	Electric Operations: Implement a marginal cost based allocation in parallel with embedded cost approach.	Page 36	PCOSS13 unchanged.	PCOSS13 unchanged.	Indeterminate at this time.
	35	Electric Operations: Modify current marginal costing approach.	Pages 36-37	PCOSS13 unchanged.	No further steps to be taken pending further review by the PUB	None at this time. The impact of marginal cost on study results would vary depending on the method chosen for incorporating marginal cost.
	36	Gas Operations: Implement a marginal cost-based allocation in parallel with embedded approach. Include further refinements to the marginal cost of natural gas services	Pages 36-37	No change.	No further steps.	None.