REVIEW OF COST-OF-SERVICE METHODS OF MANITOBA HYDRO

for the consideration of
Manitoba Hydro

prepared by
Robert Camfield
Bruce Chapman
Michael O'Sheasy
Christensen Associates Energy Consulting

June 8, 2012

Table of Contents

REVIEW OF COST-OF-SERVICE
METHODS OF MANITOBA HYDRO

for the consideration of
Manitoba Hydro

prepared by
Christensen Associates Energy Consulting

June 8, 2012

1. INTRODUCTION

1.1 Context and Purpose of the Review

Manitoba Hydro (MH or Company) retained Christensen Associates Energy Consulting (CA Energy Consulting) to review the utility's cost allocation methods in response to regulatory requirements of the Manitoba Public Utilities Board (MPUB) and to ensure that the Company's costing methodology continues to support adequately its pricing of utility services. The review covers both the electric cost-of-service (COS) methods of MH and the natural gas COS methods of Centra Gas (Centra), MH's wholly-owned subsidiary.

CA Energy Consulting reviewed these methods in light of accepted costing theory, North American utility industry practice, and regulatory requirements facing the industry. Our review of electric COS was occasioned partly by developments in electricity markets, such as the emergence of mature wholesale markets characterized by considerable price volatility, with implications for costing methods. MH's circumstances are quite special due to the relatively large proportion of sales revenue derived from export (wholesale) sales. The treatment of embedded utility costs in light of sales where marginal cost is the dominant feature presents special challenges for cost allocation.

On the natural gas side, similar costing themes arise, occasioned by the changes in the market since the last costing methodology review in the mid-1990s. Here, though, the deregulated treatment of commodity sales through to retail customers simplifies issues and shifts the focus in the direction of embedded costing issues in other parts of the business.

1.2 Outline of the Report

The report consists of seven sections, including this introduction. Section 2 describes current COS practice at MH and Centra. Section 3 reviews the rate classes that MH and Centra currently use to classify customers in their COS studies, discusses class issues and provides recommendation relating to those issues. Sections 4 and 5 review cost classification and allocation issues for MH and Centra respectively. Section 6 addresses issues common to electricity and gas services. Section 7 discusses marginal cost considerations and indicates how marginal costs can influence or contribute to COS methodology, even if embedded cost continues to be the basis of COS analysis.

2. CURRENT COS PRACTICE AT MANITOBA HYDRO AND CENTRA

2.1 Overview of COS Methods and Issues

COS analysis provides an approach to associate the financial costs of a utility to its various rate classes, thereby establishing revenue requirements for each class and providing a basis for price development in retail tariffs. The COS process either directly assigns asset values, costs, and revenues attributable to specific classes, or allocates common costs to each class. Asset values and business costs are first associated with the utility's major functions, classified according "cost causative factor" and then either assigned directly or allocated to the utility's classes. The three familiar cost causative factors are: 1) number of customers, sometimes weighted by factors that differ among classes; 2) overall level of consumption; and 3) level of peak consumption. (Revenue levels are used by the industry in limited circumstances as well.)

2.2 Manitoba Hydro's COS Structure

Rate Classes. MH serves seven major domestic classes of customers: Residential, two Small General Service, Medium General Service, and three Large General Service. Additionally, MH provides service to two small classes: the "Diesel" class (geographically remote customers, whose class name describes the generator fuel used to serve them), and Area and Roadway Lighting. MH also makes substantial wholesale sales, via its export class, predominantly to the United States through the nearest regional transmission organization, the Midwest Independent System Operator (MISO). Rate class definitions are based on customer type (Residential or General Service) and size, although size is defined by voltage for large customers, while other utilities more typically use peak demand. Similar domestic classes are found at other utilities. Wholesale services are identified at other utilities but not seen as a service "class."

Functions. MH's electric COS approach recognizes five main functions: generation, transmission, subtransmission, distribution plant, and customer services.[1] This structure is similar to that at other electric utilities, with the exception of subtransmission. Many integrated electric utilities incorporate subtransmission within the transmission function.

Classification and Allocation. MH has available the same observable information for classification purposes as other electric utilities in terms of customer numbers, usage (kWh) and peak demand (kW). Broadly speaking, the utility uses consumption to allocate generation costs, peak demand for transportation costs and customer numbers for customer service costs. This approach is similar to that of other electric utilities, although there is wide variation within these practices and allocators are tailored to utilities' needs. Highlights of MH's approach are:

- Generation costs are allocated via marginal cost-weighted energy.
- Transmission costs use a coincident peak allocator based on two seasons, with the peak being defined over fifty-hour periods.
- Subtransmission and Distribution Plant costs are allocated primarily via non coincident peak allocators, a common approach. Certain distribution costs are allocated via some combination of customer numbers, again a common practice.
- Customer costs are allocated with some form of weighted customer numbers.

2.3 Centra's COS Structure

Rate Classes. Centra serves five major rate classes: a Small General Service class encompassing residential and small commercial customers, a Large General Service class, and three classes for customers with consumption larger than 680,000 m^3 annually. Large customers are found in the High Volume Firm and Mainline Firm classes as well as the Interruptible class.[2]

[1] Other utilities often refer to distribution and general plant functions, with perhaps a different split of activities than MH's distribution plant and customer service functions.

[2] Additionally, some customers are served under special contracts, and power station service is recognized as a separate class. A cooperative service class exists as well.

Centra operates in a retail choice market: Retail consumers can elect to obtain primary (commodity) service from natural gas marketers or brokers, while continuing to obtain transport services (pipeline, transmission, and distribution as well as on-site facility services) from Centra, referred to as Western Transportation Service. In addition, Centra offers T-Service special contracts to customers, in which case customers obtain commodity and pipeline services from third parties.

Functions. Centra recognizes upstream and downstream functions: production, pipeline, and storage (upstream), and transmission, distribution, and on-site (downstream).

Classification and Allocation. Centra applies varying compositions of commodity, demand and customer charges to classify costs for its various functions. These cost causative factors are utilized in a manner comparable to that of other utilities and fairly parallel to that of electric utilities, including MH. Highlights are as follows:

- Production is commodity driven.
- Pipeline and Storage, the other upstream functions, have costs classified predominantly according to demand and secondarily according to commodity volumes.
- Downstream activities in Transmission and Distribution are predominantly classified as demand-related. Also, transmission cost allocation involves a volumetric measure (commodity gas), while distribution involves commodity gas and number of customers served.
- On-Site services are exclusively customer-related.

3. RATE CLASSES: ISSUES AND RECOMMENDATIONS

3.1 Domestic Rate Class Issues

MH's and Centra's domestic rate class definitions appear to be practical, stable, and in line with practice elsewhere. Additionally, the definitions do not appear to be raising costing issues. One exception is Centra's combination of its residential and small commercial customers in a single class: Small General Service. Separating this class into two subclasses does not appear to be an issue at the moment.

Another issue is whether to retain Centra's Cooperative Service due to lack of participation. Additionally, although it serves larger customers, Centra's wholesale T-Service fails to attract eligible LGS customers.

Recommendations. MH's organization of its domestic classes of customers is conventional and we concur with the Company's general approach. We also recommend that Centra not pursue changes to the major classes, or to the treatment of interruptible or transmission service at present. Additionally, we recommend that Centra consider closing the cooperative service option due to lack of use and low likelihood of increased participation. While T-service may be unattractive currently to LGS customers, we recommend that Centra consider retaining its T-service within its tariff package, providing that offering the 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. Selected LGS customers may prefer competitively procured gas supply (commodity) in the future.

3.2 Electricity Export Class

A major concern for MH is the designation of wholesale sales (exports) as a separate class. In view of the sheer volume of export sales, MH's strategy of recognizing a separate export class is sensible and arguably appropriate, despite the absence of wholesale customers within the utility's service territory. Within its COS process, MH has debated alternative approaches in the past, although such assessments have not satisfactorily resolved core issues, which are closely intermingled.

The appropriateness of separate designation of an export class should also be gauged according to the factors that drive resource commitments and costs: does the Company's long-term projection of the demand for electricity services, used to determine resource requirements, include exports? In essence, does MH commit to physical generation resources to serve domestic loads as well as wholesale markets, or to domestic loads only? If MH resource commitments were geared solely to serve domestic markets, the Company could consider abolishing the export class. In this case, MH would allocate export margins (wholesale export revenue flows minus short-run operating costs of generation) to domestic classes.[3] Export revenues, minus export-related operating costs, would be allocated to domestic classes using any one of several cost allocation methods, as discussed below.

However, the situation is more complicated than this statement indicates. MH engages in wholesale export sales, including both long-term contract commitments (firm exports) and short-term sales on an "as available" basis. Discussions with MH lead us to conclude that MH commits resources to serve domestic loads, but it may advance development of units to undertake firm export contracts, and MH's generation fleet might be different from the existing fleet if there were no long-term firm export sales. Accordingly, it is reasonable to consider the firm component of its export sales to be part of its resource commitments.[4]

MH's preferred cost allocation approach—allocation of net export revenues (NER) to domestic classes after firm export sales have been assigned G&T costs and after opportunity sales have been allocated variable cost—appears to be consistent with the basis upon which MH commits resources, and is also common practice elsewhere.

It is the designation of an export class that sets MH apart. Class status may help facilitate understanding of the magnitude of export revenues and profitability of export sales based upon an embedded COS study, particularly in view of MH's measure of NER, which is based on allocation of embedded generation and transmission costs and short-run variable costs, as well as specific cost assignments. However, it should be noted that the PCOSS is an embedded cost study with returns measured according to financial costs. The PCOSS returns for domestic rates are a recognized metric for determining regulated domestic rates and for measuring their efficacy. But it is not always wise to evaluate the returns and efficacy of an export class whose costs may have been incremental to the system when imposed and whose rates are not regulated but in fact determined by market forces in an external marketplace.

A more appropriate evaluation of whether export sales are beneficial is incremental benefits versus incremental costs. Incremental benefits are primarily export revenues, but

[3] We use the term "export margins" to distinguish this definition (revenues less short-run operating costs) from "net export revenues," the term MH uses in COS (revenues less allocated embedded costs, including AEF and URA).
[4] Although the existence of firm wholesale contracts for the export sale of power confers status close to that of domestic sales, these firm wholesale contacts can be interrupted if domestic reliability is at risk. In the case of power shortages, MH serves these wholesale contracts through supply call options with third parties.

incremental costs do not appear specifically within PCOSS. For COS purposes, Manitoba Hydro has adopted a convention that firm, long-term export sales bear a share of the embedded cost of all generation resources. This is certainly an appropriate COS treatment. However, it should be recognized that even though this does provide a depiction of how export sales are covering embedded allocated cost within an embedded COS analysis of the entire MH system, the POSS results for exports (i.e., NER) may not provide an accurate depiction of the benefits to the Domestic classes of exports. (This is also a reason why we recommend that costs unrelated to export sales like the URA not be charged against exports in POSS, as doing so may in fact undermine actual export benefits.)

If MH continues to recognize an export class, a second issue arises. This issue concerns the COS treatment of the two main types of export sales: long-term firm and short-term "opportunity." As a result of an MPUB ruling in 2006, both types of exports are currently considered to belong to a single class with the result that both long-term firm sales and short-term opportunity sales receive embedded generation and transmission cost allocation.[5] However, MH has argued that they should be treated separately, due to their quite different circumstances. Specifically, firm export sales involve planning with a consideration of the use of and investment in generation and transmission plant; arguably, firm exports should be subject to conventional allocation procedures related to generation and transmission costs in an embedded COS study. Conversely, opportunity sales involve "as available" energy, and do not appear to influence investment in generation and transmission plant and should therefore be accorded only variable cost within cost allocation procedures.

Opportunity sales occur only when non-firm energy supply is available. Advance notice of availability is shorter than the period for which firm rates are in place. In a sense, these sales are the mirror image of interruptible load "calls," although the degree of advance notice is different. Typically, for opportunity sales to be substantial, the utility is either *capacity long* and therefore has surplus energy, or its resource mix and demand peaks are differentiated in a major way from the regional wholesale market as a whole, a state of affairs that for MH

[5] MPUB, *Board Order 117/06*, pp. 48-51 argues and rules that exports should be considered a single class.

occurs frequently but is not guaranteed.[6] For interruptions, the utility is capacity short and restricts sales at short notice to maintain sufficient operating reserves. In both cases (interruptible and opportunity export sales), capacity costs might best be excluded from cost allocation, or at least included at a reduced level of cost allocation when compared with cost allocation for firm sales.

Recommendation. Maintaining an export class appears to be a sensible approach to an unconventional problem. We also recommend, if exports continue to be recognized as a class, that MH continue to explore ways to increase its flexibility with respect to cost allocation within the export class, to permit differential treatment in COS of firm and opportunity sales. MH should allocate only variable costs to the opportunity sales group—i.e., opportunity sales should be excluded from the allocation of fixed generation and transmission costs.

4. COST ASSIGNMENT AND ALLOCATION, ELECTRICITY SERVICES

4.1 MH's General COS Approach

MH applies for domestic electricity prices for a forward period using a projected test year approach. Changes in electricity rates over time are driven by two stated objectives, as follows:

- Recover total costs and achieve a 3:1 debt to equity ratio (75% debt, 25% equity).
- Set class level tariff prices which, over the long term, realize revenues within a range of 95 – 105% of financial costs, as apportioned among customer classes.[7]

Revenue requirements are substantially associated with capacity-related costs, which in turn are driven by peak demands and energy consumption of the customer classes. Peak demands of individual customers and customer classes are estimated from load research, as actual hourly loads of all but the very largest customers are typically not observable. In summary, the three main types of information for COS include billing determinants, projections of

[6] A different resource mix from the market tends to give rise to a different pattern or level of internal marginal costs than those prevailing in the wholesale market. This can create periodic occasions for opportunity sales.

[7] Reference Tab 10, *Proposed Rates and Customer Impacts*, of the Company's 2010/11 and 2011/12 GRA filings before the PUB.

financial costs (revenue requirements), and load research. Such data are standard inputs in cost allocation studies.

Table 1

MH Classification of Total COS by Function, PCOSS11

Function	Classification	$ million	% Wt.	% share
Generation	Energy	$ 922.1	100%	57.7%
Transmission	Demand	$ 193.7	100%	12.1%
Subtransmission	Demand	$ 75.3	100%	4.7%
Distribution Plant	Demand	$ 219.6	71%	13.7%
	Customer	$ 91.1	29%	5.7%
Distribution Service	Customer	$ 97.3	100%	6.1%
Total		$ 1,599.1		100.0%

4.2 Export Sales and Cost of Service

We investigated two fundamental COS issues regarding export sales:

1) *Direct assignments to the export sale class*: Should the export class have costs unrelated to exports assigned to it?
2) *Allocation of Net Export Revenues (NER)*: Whether or not exports continue to be treated as a designated class, are there enhanced means to allocate net export revenues or net margin back to domestic rate classes?

Each issue provides MH with options regarding cost allocation in the future. We discuss each below.

1) Direct Cost Assignments to the Export Class. The MH COS process assigns several specific cost categories to the export class, including the Affordable Energy Fund (AEF), and the Uniform Rate Adjustment (URA).[8] MH has discussed with us the nature of these cost categories, and we do not find direct causal linkages between the underlying nature of these costs and MH's wholesale export sales. COS should reflect cost causation and the costs associated with the AEF and URA are not caused by the export class. Some might propose that it is fair and reasonable to allocate these costs to the export class, possibly due to the

[8] The costs of demand-side management (DSM) programs were also set against export revenues in PCOSS08 in accordance with PUB Order 117/06. If marginal costs are above the sum of financial costs and DSM program expenditures, benefits of DSM accrue to the MH system as a whole.

prevailing margins in export sales or to a claim that these costs enable some export sales in some fashion. However, we suggest that criteria of fairness and equity be applied to pricing and tariff design only, rather than to cost allocation. COS aims to create a benchmark of cost causation so that the difference between revenues and costs can be known. This goal should apply to the export class likewise. As AEF and URA are not export-related costs, assignment thereto is essentially a breach of the cost causation principle.

Recommendation. We recommend that MH consider assigning these cost categories directly to the domestic sales classes in a manner that seems most appropriate. However, if MH feels that these costs are not caused by either the domestic classes or the export class, then they should be excluded from the electric COS. To include them in this case would distort the real cost of providing electricity, which is the purpose of COS. The impact of this action may be slight in terms of total cost allocation but it would be consistent with accepted COS concepts.

2) NER Allocation to Domestic Classes. The current approach to allocating NER involves allocation to domestic classes according to the total cost to serve each class *not including direct assignments*. In effect, higher-cost customers receive a larger share of revenues per kWh than do lower-cost customers. This may satisfy one view of fairness but it may be worthwhile for MH to explore alternative allocation schemes.[9] Reasonable alternative methods can be considered by MH. These methods could consider: 1) using existing allocators, such as those used to assign capital-related G&T costs; 2) allocators that recognize the differential risk absorbed by customer classes as NER oscillates over time; or 3) allocators based on some fairness-based criterion.

We have seen a fourth type of allocator proposed called “energy available for export.” Under this approach, the assignment of capacity costs to individual classes suggests an implicit class entitlement to the underlying capacity (MW), and the energy that can be produced by it. Within the COS process, the class load shapes determine the share of the total energy which potentially could be produced by the capacity entitlement assumed by the several classes of

[9] As general rule, we suggest that fairness criteria be accounted for in pricing and tariff design only, rather than within the cost allocation process. However, the unconventional challenge posed by the disposition of NER opens the possibility of using fairness criteria in cost allocation treatment of NER.

service. For each class, the remaining share of the potential energy that could be produced but is *unclaimed*—i.e., available but not consumed—by the class is thus available for sale as export energy.

All the above methods, as well as the current method, face the challenge that retail rates are reduced, distorting downward an already low price signal (relative to some measures of marginal cost). Two potential solutions to this problem may be worth considering:

- <u>Lump Sum Bill Credits</u>. Credit NER amounts to customer bills in lump sums. This approach avoids reducing volumetric (energy and demand) charges. Determining institutionally acceptable lump-sum credits may nonetheless result in size-based bill credits that begin to approximate a volumetric credit, since a single credit may not be appropriate for all customers in a class.
- <u>Bounded Recognition of Benefits.</u> Do not allocate NER back to domestic classes directly. Instead, place NER funds in a separate account classified as retained earnings for use in future construction or debt buy-back. This approach has the virtue of insulating retail rates from swings in NER over time, as well as lowering the funding cost of future capital expenditure. MH could set upper and lower bounds on the account, with excess being transferred to the government and shortfalls leading to supplemental funding from the government. The bounds would be set wide enough to make this an infrequent event.[10]

Recommendations. 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.

4.3 Generation Classification and Allocation

The generation cost allocator for domestic and export sales, referred to as weighted energy, weights energy consumption for three time-of-day periods in four seasons, according to the power prices used in the Company's Surplus Energy Program (SEP), which are effectively short-run marginal costs. By weighting energy according to SEP prices, the Company's approach accounts for the differences in economic value of the underlying resources to

[10] BC Hydro has a protocol for managing swings in export earnings by limiting the amounts allocated back to domestic classes.

supply energy, by timeframe. MH's cost allocation appropriately integrates marginal costs into generation cost allocation, thus recognizing the cost allocation objective of resource efficiency within the process of fully distributed costing.

However, it is worthwhile to examine the nature of the marginal costs being used. At present, these costs do not include explicit marginal reserves costs, which reflect capacity costs. If such costs are missing, then it may be worthwhile to consider adding them or adopting an alternative cost allocation approach that makes use of both capacity and energy costs.

MH can approach this problem in two ways. First, it can conduct research to develop a more comprehensive measure of marginal costs that incorporates marginal reliability costs. Second, it can adopt the more traditional alternative of converting generation to an allocator that reflects demand to some degree.

Recommendations. We recommend that, for the present, MH retain its current methodology, which appears to be well founded. For the longer term, we recommend that MH review potential enhancements and an alternative.

- The Company can improve this methodology by reviewing its marginal costs and incorporating marginal reserves costs.

- If research into marginal cost patterns reveals a higher degree of time variability than the time-of-use structure carries, MH could move to hourly computation of marginal cost and hourly load profiles by class.

- Alternatively, in an effort to incorporate capacity costs to a greater extent than is done at present, MH can apply a more traditional embedded cost-based approach using the equivalent peaker allocator. Since the equivalent peaker allocator can be computed readily, we suggest that MH evaluate its impact on cost allocation in tandem with any investigation of the suggested marginal cost enhancements (hourly computation and incorporation of marginal reliability cost).

4.4 Transmission Classification and Allocation

Transmission is classified by MH as 100% demand-related, which is common practice throughout the industry. MH utilizes a summer and winter coincident demand peak allocator based upon the average of the highest 50 peak hours in each season, adjusted for losses, for transmission facilities larger than 100 kV. Peak loads on the transmission system are approximately equivalent in magnitude in both seasons. High winter loads are caused by domestic retail space heating, while summer loads can be comparatively high because of export sales.

4.4.1 Functionalization and Allocation of HVDC Bipole Facilities

The Company's transmission network consists of a conventional meshed alternating current (AC) system and two long-distance direct current (DC) facilities, referred to as Bipole I and Bipole II. In addition, MH is currently planning to construct and operate a third long-distance DC transmission line, Bipole III. The Company's Bipole facilities transport power produced by large-scale hydro facilities in the north to load centers in the southern tier of Manitoba. The distances are substantial.[11] The Bipole lines are interconnected to the AC grid at the Company's Dorsey Station.

For purposes of cost allocation, MH functionalizes the costs associated with its Bipole I and II transmission facilities as generation-related, whereas the Company's AC-based transmission facilities are uniformly functionalized as transmission-related. The costs of the Dorsey Station are also considered to be transmission-related, including the costs of the inverters for conversion of DC supply to AC for entry into the Company's meshed network.

It is common practice to consider transmission interconnection facilities as generation-related, where the facilities are specific to interconnection and the costs are thus assignable. However, the distances are generally short and thus do not involve the provision of transport services. For cost allocation, the appropriateness of functionalizing the Company's Bipole facilities as generation can be gauged by applying several general criteria, as follows:

[11] Direct current is the preferred technology for the transport of large loads over extended distances because of lower thermal losses and reduced phase angle issues. Across the U.S., a number of DC facilities are currently being planned in order to transport power from often remote sites of renewable resources to load centers.

- Are observed flows on the facility representative of the net of numerous counter flows between points of power injections and load withdrawals?
- Are flows on the facility of a uniform direction?
- Does the facility provide improved reliability for the AC meshed network as a whole, in isolation of any specific generation facility?
- Does the facility provide increased power flow capability to the AC meshed network?

In the case of MH, the transmission Bipole facilities do not involve multiple load injections and load sinks. Moreover, there are no counter flows; power flows uniformly from generation in the north to loads in the south. However, the Bipole facilities increase the technical capability of the meshed network, in isolation of the tie to generation in the north. Accordingly, it is appropriate for the Company to consider classifying the Bipole facilities as generation.[12]

The Dorsey Station is a large facility, where the power converters for the Bipole I and II lines and conventional power system equipment reside. The conventional equipment elements—and a share of common costs—of the Dorsey Station provide reliability benefits (monitoring, control and switching, voltage support, etc.) to the system as a whole. Accordingly, the costs associated with this equipment, including the substation yard, should be functionalized as transmission-related. The DC facilities at Dorsey contribute to system stability and provide series compensation to the entire meshed system. In the absence of these facilities, MH would likely need to have in place alternative facilities, at considerable investment cost. MH may wish to functionalize the share of the costs of the Dorsey Station related to hydro generation (mainly inverters for DC to AC conversion) as generation, after accounting for the share of costs that would have otherwise been placed in service in order to maintain system

[12] These criteria, here applied to classification of transmission facilities, are somewhat akin to the seven-part test adopted by the Federal Energy Regulatory Commission (FERC) to determine the applicability of incentives for transmission investment. In Order No. 679 (679-A), *Promoting Transmission Investment through Pricing Reform*, July 20, 2006, the FERC set forth criteria to gauge whether several non-exclusive incentives that have been made available to sponsors of transmission facilities, in order to advance transmission projects, constitute just and reasonable rates. These incentives include: accelerated depreciation, earnings on construction work in progress, incentive return on equity, rate of return based on a hypothetical capital structure, full recovery of development costs should the project be cancelled, recovery of abandonment costs should the project be cancelled, and availability of declaratory order by the FERC.

reliability of its meshed network. The shares of Dorsey attributable to generation and to transmission can only be determined through estimation procedures.[13]

Recommendations. We recommend that MH continue to treat the bipole facilities as generation. We also recommend that MH investigate its cost allocation approach for the Dorsey Station. It is our 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.

4.4.2 Transmission Service from Radial Taps

MH serves large industrial customers at transmission voltages, where power service is interconnected to transmission substations. In selected cases, moreover, the Company serves industrial customers at high transmission voltages through high voltage tap interconnections; voltage transformation is not involved.[14] These high voltage customers should not be charged for the costs associated with subtransmission or substation facilities, and they are not under MH's current PCOSS methodology. However, they should bear some responsibility for the cost of high voltage radial taps which serve them. The costs of these high voltage radial taps for customers served at or above 100 kV are mis-classified as lower-voltage subtransmission. These costs are thus integrated with other subtransmission cost elements when in fact they should not be. Through the current PCOSS process, the average of the total costs classified as subtransmission facilities as well as higher voltage facilities is charged to all customers receiving subtransmission voltage service and lower. However, by placing the high voltage radial taps within subtransmission, high voltage customers do not bear their correct cost responsibility for these radial taps.

[13] The question of whether facilities associated with DC-AC conversion should be classified as generation or transmission hinges on the implied configuration of the MH's network under the counterfactual case. Namely, had MH installed conventional thermal generation, also interconnected to the meshed network at Dorsey, would the necessary transmission facilities and costs been of an equivalent level? No doubt, MH would have installed a different configuration of equipment in order to accommodate thermal generation of approximately equal capability. The costs of this alternative transmission equipment bundle, which can be gauged only through design simulation, would offset some if not much of the observed investment of Dorsey in its current configuration.

[14] The customers provide voltage transformation with facilities situated at the customer's site.

Recommendation. We recommend 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 subtransmission cost.

4.5 Subtransmission Classification and Allocation

Subtransmission costs are currently classified as 100% demand-related and allocated to customer classes using NCP demands. This demand-related classification approach is very common throughout the industry and certainly reasonable for MH. For subtransmission, industry practice suggests that either CP or NCP demands may be appropriate—selection is an empirical issue.[15] (Industry practice does not usually suggest consideration of a role for energy in subtransmission cost allocation.)

The choice of allocator by MH should be based on load diversity across MH's various subtransmission networks. To the degree that loads of subtransmission systems are: 1) highly correlated with the system peak demand, and 2) coincident peak demands are the basis for investment in subtransmission, MH should consider adopting a coincident demand-related allocator for subtransmission. If the two conditions above are not true, then retaining an NCP allocator appears preferable.[16]

Recommendation. We recommend 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.

[15] The objective of COS allocation is to utilize an allocation approach that best links costs to the underlying definition of services rendered (cost causation). The service demands of customers and physical characteristics of service providers vary dramatically from one utility to another, and service providers and regulatory authorities employ a variety of cost allocation approaches. In the case of subtransmission, it is common to use either coincident or non-coincident peak demands to allocate fixed costs, including capital- and operations-related charges. In the case of the lower service voltages within primary and secondary distribution wires services, it is common to allocate fixed charges according to non-coincident demands.

[16] The level of load diversity can be gauged according to coincidence factors observed at the time that system peak loads are being approached—e.g., the top 50 hourly loads. Also, for meshed subtransmission networks, it is important that the analysis select measurement points that avoid measurement error as a result of flow double-counts or overlap.

4.6 Distribution Plant Classification and Allocation

Because of the diversity of facilities and the resulting variation in facility costs, multiple service levels, and the load characteristics of customers, distribution is classified by MH, and typically by the industry, as both demand-related and customer-related. MH uses an NCP demand by rate class allocator, and the customer allocators are based on either the simple number of customers or weighted numbers of customers.

4.6.1 Classification of Distribution Plant Costs

MH classifies the various categories of distribution plant costs using several methods, as shown in Table 2, below.

Table 2
Classification of Distribution Costs,
COS Allocation Approach of MH

Customer- and Demand-Related Shares, Cost Causation (Splits)		
	Current MH Approach	
	Demand	**Customer**
Stations	100%	0%
Poles and Wires*	60%	40%
Line Transformers	100%	0%
Service Drops	0%	100%
Meters	0%	100%
* Based upon a 1990 study by Ernst & Young and accepted for use by MH since 1991.		

In Order 17/10 one intervenor criticized the classification and allocation of distribution cost recognizing a customer component using the Minimum Distribution System (MDS) and the Zero Intercept Method. This intervenor also recommended recognition of an energy component for certain distribution cost.[17]

For distribution, the NARUC cost allocation manual recognizes demand- and customer-related allocation vectors. Dual cost attribution—i.e., demand- and customer-related—for

[17] Order 17/10, Direct Testimony of P. Chernick.

electric distribution is based on the notion that interconnection of loads to the distribution system induces the service provider to incur some level of costs without regard to load size—thus the terminology *minimum-size-of facilities* method cited above.

The minimum facilities, along with meters and service drops, make up the plant investment portion of customer-related costs, as normally interpreted. Analytically, the share of distribution facilities in excess of the minimum costs is essentially residual to minimum distribution costs and, as a consequence, is classified as demand-related costs. In essence, distribution costs above the minimum costs for interconnection of customers to the network are related to capacity to serve load; distribution facilities are sized accordingly.

In addition to any controversy regarding the classification of distribution plant costs as both demand-related and customer-related, some practitioners opine that some types of distribution costs are related to energy consumption, or more properly load factor. For example, transformer losses consist of no-load and load-related losses. However, as a matter of industry practice, transformer sizing is based exclusively upon forecasted peak demand of the load being served by the transformer. More generally, using energy as a driver of distribution cost is not common practice and, in our view, is not appropriate as a general rule. The cost causation principle suggests that cost allocation should align with the main factors (cost drivers) that induce service providers to install and maintain distribution facilities and equipment. Distribution plans and decisions to expand are driven by expected peak loads and customer interconnection (hook-ups), not energy. Thus, energy should not generally be used as a cost allocation vector, for distribution wires services.

Recommendations. MH should continue to classify its distribution plant costs via a combination of demand- and customer-related factors. We also recommend that MH not consider energy as a basis for the allocation of distribution plant costs. Also, 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.

4.6.2 Allocation of Distribution Plant Costs

MH allocates demand-related costs of distribution, including distribution substations and circuit lines, based upon the highest NCP-rate class peak for each respective rate class. This is common in the industry. However, some utilities will use coincident peak allocators for distribution and some will use the sum of all of a rate class's individual customer peaks (NCP-customer peaks) for distribution demand allocation. Some will use a combination of NCP-rate class peak and NCP-customer peaks.

MH's approach suggests a considerable level of non-coincidence in the peak demands across primary feeders and secondary lines. This is likely in view of the service territory. Loads of urban substations and primary feeders may be highly coincident, with loads reaching peak levels at about the same time as the system peaks. However, loads of rural substations and feeders may be much more diverse, with peak loads taking place during timeframes that are considerably removed from the times that the system experiences peak demands.

The goal is to select a demand allocator which best reflects the load expectations of the planners who designed and installed the system equipment. MH can conduct research regarding these load peaking expectations and the correlation of planned and installed distribution plant equipment usage with system coincident peaks, non-coincident rate class peaks, or non-coincident summed customer peaks. However, such research is often expensive and may not change results significantly. There is not necessarily one right method for all utilities, as circumstances and data availability (for the selected allocator) vary by utility.

Recommendations. We recommend that MH retain its current method of allocating distribution plant costs, as it is in line with industry practice. We also recommend, 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.

4.6.3 Service Voltage

Within its COS and tariff rates, MH may wish to consider the recognition of a service level modification. Certain mid-sized commercial customers, situated near distribution substations take service directly from the substation facility. In contrast, most mass market and mid-sized customers take service off primary lines and secondary service. A question, then, is whether customers served right outside substations (or who may have a MH-owned dedicated substation and be the only customer served from it) should bear responsibility for a share of the costs of primary distribution circuits. This concept may require that a decision be made as to the allowable number of spans necessary to serve the customer that are permissible under a definition of *service outside of the substation.* This is commonly done by utilities by using maximums of possibly 2-4 spans of lines between poles. Direct service from substations implies lower investment costs and line losses to provide service, when compared to the costs associated with most customers in their respective class and tariff category. Customers with special service characteristics should be accounted for within COS, providing that such situations can be identified within cost and billing records.

Primary voltages are greater than secondary voltages. Customers taking service at primary voltage do not require equipment at secondary voltage. This should be taken into account in COS.

These service levels also possess a distinction of phase service, either single-phase or three-phase service. Three-phase is usually more costly and this should be taken into account in COS if possible.

Recommendation. We recommend that MH consider accounting in its COS methods for the fact that these customers do not require primary lines investment to serve them.

- 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.
- Consider separating lines into two service levels: primary and secondary, each with separate allocators.
- Consider a further separation of cost into single- and three-phase for facilities such as line transformers.

4.6.4 Allocation to Area and Roadway Lighting

MH identifies three allocators in which Area and Roadway Lighting (ARL) weighting is a current concern: Collections and Billings, Distribution poles and wires, and Marketing R&D. Additionally, there is some degree of concern about the use of load research data for ARL. We discuss each of these concerns below and provide recommendations.

Collections. Collections costs are determined for the COS study and allocated to rate classes based on a weighted customer allocator referred to as C12 in the COS study. The class weights are based on a 1991 study that determined the total collection costs attributable to each class. ARL's customer weight is based on estimated fixtures per customer.

Billings. Billing costs are determined for the COS study and allocated to rate classes based upon a weighted customer allocator referred to as C11 in the COS study. The ARL component of C11 is constructed in the same manner as that of C12, above.

Distribution Poles and Wires (P&W). Distribution P&W costs are partly directly assigned to ARL and partly allocated based on the class's share of customer and demand allocators. ARL is assigned a full share of demand-related secondary costs even though some fixtures do not use common secondary circuits. As an offset, ARL is not assigned any portion of customer-related secondary costs even though some fixtures do in fact use common secondary circuits. The net impact of these rules is unknown as MH does not currently have an estimate of the extent to which ARL fixtures use common secondary circuits.

Marketing R&D. Marketing R&D costs are the responsibility of ARL based on the weights calculated for allocator C13. The cost captured in MH's COS study for Marketing R&D are related to enhancing business development in Manitoba, developing the corporation marketing plan, conducting customer surveys, coding, and information data bases. Given these types of costs, a question arises as to the extent to which Marketing R&D touches on ARL accounts.

Load research for ARL. MH has conducted load research to investigate lighting's contribution to peak demand and total energy consumption. This research was undertaken over a decade ago, in 1997-1999. Lighting consumption is fairly stable over time and can be followed by keeping track of the number of poles, fixtures and bulbs. However, load research enables periodic confirmation of actual consumption.

Recommendations.

Collection and Billings Allocation. 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.

P&W Customer Allocation. 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.

We further recommend that MH review whether the manner in which ARL assets are connected to the underground system differs 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.

Marketing R&D Allocation. We recommend 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.

Load Research for ARL. We recommend 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.

4.7 Major Cost Assignments

Direct assignment of costs should follow the same logic as cost allocation: cost causation. A cost that can be linked directly to a specific rate class should be so assigned. We list below MH's direct assignments of major cost categories and provide recommendations regarding them.

Purchased Power. Per Order No. 117/06, MH directly assigns energy import and wind energy purchase costs as charges against export sales. (These costs are the commodity costs. Transmission costs are discussed below.) In a median year, which is the basis of the prospective cost-of-service study, import purchases are made for economic arbitrage or for reliability reasons to satisfy export sales. Even if these imports are expected to be made during hours in which exports are not being made, it is reasonable to conclude that these imports enable hydro resource build-up for later export sales, as long as these imports are not occurring at times of hydro spillover. Furthermore, imports are smaller than total exports. (Naturally if imports were greater than total exports for the test period, it is logical to conclude a portion at least of the imports would be serving domestic needs.)

If the prospective cost-of-service study were conducted on a probabilistic basis, as opposed to a discrete median water flow expectation, there might be a small element of import energy costs used by domestic customers. However, for import cost to be considered on a probabilistic basis would require that many other cost components in the COS study be evaluated likewise. This probabilistic approach likely would be overly complicated and likely would create little, if any, change to the COS results for import cost assignment. Such an effort is unnecessary in our view.

Recommendation. We recommend that import commodity costs continue to be assigned as charges against exports, as long as imports remain moderate in size compared to exports.

Wind Energy Purchases. The foregoing argument applies to imports from conventional generation sources. However, wind generation purchases of electricity are combined into MH’s overall resource mix of generation. This total resource mix then serves the needs of domestic and export sales.

Recommendation. We recommend that both domestic rate classes and export sales be responsible for power purchases from wind farms within PCOS. Wind generated energy becomes blended into MH's overall energy supply for serving both domestic rate classes and export sales. Therefore, wind can be considered as contributing to and enabling domestic and export sales of firm energy.

Transmission Service Fees Related to Purchased Power. Transmission reservations are assigned to the export class, since they are charged to customers who purchase power exported by MH. It is reasonable to presume that these fees are necessary to enable export sales. However, if export sales had never occurred, it is highly probable that import capability would still have been constructed to serve MH's domestic reliability needs, since it would be more cost effective to use imports to meet dependable energy and reliability requirements than to construct thermal units for this purpose. In fact, if exports were to cease for whatever reason, this import-related transmission capability would continue in place; otherwise additional thermal units would be needed for domestic reliability.

Recommendation. We recommend that transmission service fees attributable to export facilitation be assigned to exports, with residual fees being assigned to domestic classes, due to the inherent value to domestic customers of imported power, which requires transport capability.

Thermal Units. Order 117/06 directed MH to assign all thermal costs, both fixed and variable, to export sales. Subsequent clean air requirements restrict the use of *new* thermal generation for domestic dispatch. Order 116/08 required that MH assign 50% of thermal plant fixed cost and 100% of thermal plant variable costs to exports.

All but one of MH's thermal units are fueled by natural gas. The exception is the legacy unit Brandon #5, for which coal is the fuel source, with an approximate capacity of 130 MW. Brandon Unit #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 purposes to serve new export sales, whether firm contract or opportunity sales.

MH's COS studies are prospective, but based upon historical years with "median" water flows. Dispatched energy from thermal units during a COS test year is used for the benefit of domestic customers and not Export sales. Under the assumption of median water flows, natural gas units would not be necessary to serve export sales on an existing firm contract basis and would not be economically feasible for even opportunity sales. It is possible that under an *extreme event*, a natural gas unit could be used to satisfy an export sales obligation, but, as stated, the basis of MH's COS is NOT an *extreme event* regarding water flows, but merely *median* water flows. If the COS study were performed on a probabilistic basis, there might be a small probability that thermal generation would support exports under extreme conditions, and leading exports to have some small thermal cost obligations. Additionally, a recent commission direction has led to an assignment of 50% of thermal fixed cost to exports and 100% of variable cost to exports.

Recommendations. Brandon #5 is the only coal unit. It is relatively old, restricted to emergency use and is due to be retired in a few years. We recommend that Brandon #5 be assigned to domestic classes only.

The current assignment of 50% of thermal fixed cost and 100% of variable cost to exports greatly exaggerates natural gas units cost responsibility and is unfairly burdensome to exports. If some recognition of natural gas cost responsibility to exports is still desired regardless of the “median” water flow conditions for the COS, we recommend the use of the pool of generation cost to allocate natural gas cost to domestic and exports. This should be more appropriate than the current 50/50 fixed and 100% variable cost allocation.

Trading Desk Operations. This area’s costs have been split between Domestic and export sales. This is appropriate since even if there were no export sales, a trading desk would be appropriate for MH, as it is for nearly all interconnected electric utilities. At other utilities, trading operations take place, reducing power cost generally, for the benefit of all customers. Thus, even if no trading activities take place at MH during the test year that can be described as directly related to domestic class requirements, a portion of this function could reasonably be assigned to domestic responsibility.

Recommendation. We endorse this allocation and recommend periodic reviews of the allocator of trading desk operations to reflect the fact that trading activities benefit all customers directly, not just indirectly through net export revenues.

MISO/MAPP Fees. These fees are also split between Domestic and export sales. This approach is appropriate since these fees represent charges incurred to deliver power cost reductions in part to domestic classes and in part to export sales.

Recommendation. We endorse this allocation and recommend periodic reviews of the allocator that apportions MISO/MAPP fees to the domestic rate classes and export sales.

URA Program. Per Order 117/06, MH credits Residential General Service Small, Medium , and the Area and Roadway Lighting classes with a share of forgone revenue that result from the Uniform Rate Adjustment (URA). The full amount of this credit is deducted from export profits. The result is that within PCOS the resulting margin obtained in the export market is misstated. While it is true that many of the costs within PCOS are common and therefore allocated such that *complete* accuracy in cost determination by rate class, including export sales, may not be achievable, these common costs (and the direct costs that are assignable) are linked to providing the product, and the cost-of-service effort should determine the most accurate possible cost representation for each rate class, including export sales.

We believe a better approach would be to determine whether, or to what degree, the costs of these programs are linked to domestic sales. If linkage exists, then the program cost should be assigned as domestic class responsibility in PCOS. (For example, URA costs do not vary with export sales but do vary with sales to the affected rate classes. MH should allow this subsidy to reveal itself in the domestic rate classes PCOS.) If linked to neither domestic nor export sales, these program costs should show up outside PCOS at a total MH company level as reductions to eventual contribution to reserves. COS should reveal the cost coverage that is actually being achieved by each respective rate class. If a particular class is deemed to be appropriate for subsidies, this is a policy decision and can rightfully be made, but the COS must be a clear benchmark for cost causation and rate revenue coverage.

Recommendation. We recommend that URA cost be reflected in COS within domestic rate classes unless it can be determined that it is in fact not linked to domestic. If URA is not linked to domestic and it is not linked to exports, then URA program costs should fall outside PCOS. If an agreed-to subsidy is in order (like URA), then explicit treatment outside of the COS study informs the reviewer of its magnitude.

DSM Programs. Regarding DSM cost, Order No. 116/08 required the assignment of DSM cost directly to exports, along with the crediting of energy savings to domestic load for cost-sharing purposes. We disagree with this cost treatment, because DSM is not driven by export sales. It could be argued that DSM does free up load that can be sold to exports but this is a possible consequence and not the purpose for which the DSM programs were instituted. DSM cost does not vary with export sales but do vary with marketing to domestic customers.

Recommendation. We recommend that DSM program cost be assigned to the domestic rate class which they end up benefiting (via reduced load and allocations), since this treats DSM cost in a manner identical to any other resource. This inherently ensures that DSM programs be cost effective.

AEF Program. AEF contains cost related to natural gas efficiency improvements which have nothing to do directly with electricity sales in either the domestic or the export markets.

Recommendation. We recommend that this cost not show up in COS for any rate classes unless it is related to electricity sales.

5. COST ASSIGNMENT AND ALLOCATION, NATURAL GAS SERVICES

5.1 Centra's General COS Approach

Centra recognizes upstream cost functions including production, pipeline, and storage functions; and downstream categories include transmission, distribution, and on-site functions. Centra's cost allocation process assigns all cost elements, including corporate overheads, to upstream and downstream functions. Once assigned to functions, detailed cost categories are classified as demand-, commodity-, or customer-related activities. Demand-related costs cover capacity-related requirements, defined as maximum daily throughput quantity, whereas commodity-related costs refer to costs associated with annual energy throughput.

As with methods for electricity services, the COS approach of Centra consists of well established fully distributed allocation procedures. For each of the identified upstream and downstream functions, Centra's cost classification and corresponding costs are shown in Table 3 below.

Table 3

Classification of Cost Categories,

Centra's Cost Allocation Process

Function, Cost Category	Classification Method	Costs of Functions	
		Amount (millions)	Share of Total Cost of Providing Gas Service
Production	Commodity (100%)	$353.3	65.1%
Pipeline	Demand (94%)	$ 15.5	2.9%
	Commodity (6%)	$ 1.0	0.2%
Storage	Demand (61%)	$ 18.4	3.4%
	Commodity (39%)	$ 11.7	2.2%
Transmission	Demand (67%)	$ 11.7	2.2%
	Commodity (33%)	$ 5.8	1.1%
Distribution	Demand (71%)	$ 22.7	4.2%
	Customer (29%)	$ 9.3	1.7%
On-Site	Customer (100%)	$ 93.3	17.2%
Total Cost of Gas Service*		$542.7	100.0%

*Totals may not add due to rounding.

5.2 Downstream Demand Cost Allocation

The only potentially noteworthy methodological issue of cost allocation at Centra uncovered during our review involves downstream demand-related cost allocation. Centra utilizes the peak-average (PAVG) allocation method to distribute the larger cost elements of transport services (pipeline, transmission, and distribution) as well as the capacity charges related to storage, to customer classes. Transport costs include carrying charges (interest) on net investment, capital depletion, corporate taxes, and comparatively minor charges for insurance and property taxes; and operating expenses such as maintenance costs and administrative overheads.

The PAVG structure reflects the view held by some that peak demand alone may not adequately address capacity cost responsibility with respect to transport services.[18] PAVG and similar allocators tend to shift cost allocation away from peak-coincident classes, such as those receiving firm service, to other classes and customers, such as non-firm service customers. Also, PAVG can be interpreted as a "fairer" allocator by those who conclude that

[18] NARUC's Electric Utility Cost Allocation Manual characterizes the justification for use of an "average and excess" allocator as follows: "… a utility's capacity serves a dual function – while system peak demands establish the level of capacity, providing continuous service creates additional incentive for such capacity costs". (p. 81.)

the more a class "uses" the system in terms of amount of commodity consumed, the greater their allocation of transport cost should be.

Centra's application of the peak-average allocation methodology rests on solid institutional precedent. One well-known method is the Atlantic Seaboard formula, where facility costs are allocated according to peak day and energy throughput, each weighted by 50%. Another method is the United formulation (United Gas Pipeline, 1973), in which the weights are 25% and 75% for peak day and energy, respectively. For pipelines, the Federal Energy Regulatory Commission adopted the so-called Modified Fixed Variable approach during the 1980s. All three cost allocation methods are variations of peak day-average throughput combination allocators. Moreover, the *Gas Distribution Rate Design Manual* of the NARUC describes the average and peak method (i.e., peak-average) as one of the most commonly used approaches for allocation of demand-related (fixed) costs (at page 27).

However, discussions with planners and general intuition suggest that transport costs are driven largely by peak demand and transport distance (line length), and secondarily by the type of terrain and factors associated with infrastructure density.[19] Peak day demand (maximum daily throughput) is an observable causal factor for cost allocation. However, length of transmission and distribution mains attributable to customers is less observable[20] and it is also difficult to associate distance measures with customers or customer classes because of practical and institutional limitations. As a consequence, to the degree that transport distances are accounted for in cost allocation, it is necessary to utilize surrogate allocation metrics.

One potential surrogate metric for length of mains is number of customers. MH could evaluate this idea by estimating the shares of total costs of mains attributable to: 1) peak capacity ("max day") and 2) line distances. The share attributable to max day would be

[19] The general relationship between distance and transport costs is common to virtually all modes of transportation. For example, rail and airline freight charges, and output measures also, are typically recorded with reference to ton-miles; estimates of electric transmission and pipeline construction costs are expressed in costs per mile; and commuter bus and train fares are differentiated with respect to distance.

[20] However, methods of approximation are available. In a world of complete information, customers would be charged for the size and the length of mains used to serve them, under strict cost causation. However, the transport distances/facility lengths applicable to individual customers and, hence, customer classes are not observed, nor can they be estimated easily in the absence of specific area studies.

allocated according to peak day responsibility, and the cost share attributable to transport distances (line length) would be allocated according to class number of customers.

Another potential surrogate is energy sales, a metric currently in use. Energy use makes sense as a proxy if the average energy per customer, for customers taking service from Centra's distribution system, does not vary much (i.e., there is fairly homogenous consumption per customer.) If this is true, energy would capture the average/typical distance of mains (that is, the expected value of distance per customer) about as well as number of customers served.[21] Under such a condition, even under strict cost causality, Centra would have good reason to retain its peak-average allocation metric.

Recommendation. For the reason of institutional precedent and recognizing the difficulty of incorporating transport-related metrics by rate class, we support Centra's peak-average demand allocator for transmission and distribution. However, it may be useful to investigate a peak-customer allocation metric for future consideration, as peak day and transport distance are likely the key cost drivers of transport services. Proxies for distance metrics may be investigated for both transmission and distribution services. Detailed recommendations are as follows:

- **Transmission and Distribution.** If cost causation is the paramount criterion for selection of an allocator, then Centra may wish to explore the development of a combination allocation metric that includes maximum day and number of customers.

[21] Energy may serve as an appropriate proxy for distance if one of two conditions holds:

- Transport distances within distribution are related systematically to size (total consumption) of individual customers, particularly large general service customers.
- Energy use per customer is sufficiently homogeneous across customers.

Even under strict cost causation, Centra's peak-average demand allocator would appear to capture transport distances if either condition holds. First, if the energy consumption of the typical customer of the several classes is approximately proportional to the expected value of line distances, energy can serve as an appropriate proxy for allocation of distance-related share of total costs. Second, if average use does not vary greatly across customers, an energy allocator does not result in systematically biased cost allocation results, if customers are randomly distributed within distribution systems. Such a result can be demonstrated analytically.

However, it is not likely that the first condition—i.e., that energy is systematically related to distance—is satisfied; it is virtually unimaginable that line distances are systematically related to energy sales, across the several systems of a gas distributor. Regarding the second condition, we can expect that, for virtually all gas distributors, the statistical variation of within-tariff consumption per customer may be comparatively small, at least for most customers. However, customers located on transmission and the larger diameter distribution mains and under higher pressures are likely to have considerable variation in average energy, stated on a per-customer basis, thus violating the condition.

- **Combination allocator weights.** Under certain conditions, energy can serve as a useful surrogate to capture the underlying cost factors that drive the costs of distribution facilities. We recommend 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, we recommend that Centra consider conducting a cross-sectional statistical analysis of costs and cost drivers, reflected in historical work order records.

5.3 Additional Recommendations

Seasonal Costs and Rates. We recommend that 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.

Cost Deferrals of Purchased Gas Variance Accounts (PGVAs). Centra maintains a number of cost variance accounts, one of which records differentials attributable to projected costs and actual revenues related to forecast and actual heating value of gas purchases.[22] Within its reconciliation procedures, as reflected on customer bills, Centra should include only customers with monthly bills that are determined according to energy sales volumes of customers.

6. ISSUES COMMON TO GAS AND ELECTRICITY SERVICES

6.1 Common Features in Gas and Electric Services COS Methods

The Company's COS methods for gas and electricity services are similar to the degree that the supply technologies have common characteristics and cost causative factors. Because of differences in the underlying technologies of the two services, however, there are necessarily differences in methods. This is most evident in the functional definitions and customer class designations. In the case of gas services, storage services play an essential role and thus have a specific function category, which is common practice in gas services.[23] In electricity, MH assigns class designation to its wholesale export sales, in view of the scale of sales to U.S. markets.

[22] For this PGVA deferral, we recommend that Centra retain its current approach to managing the accounting variances, which involves calculating the difference between projected and actual sales quantities, attributable to differences in heat content within gas purchases.

[23] The cost of energy storage through water reservoirs, which is considerable for MH, resides implicitly within MH's total costs of hydro generation.

Recommendation. We do not find good reason for MH to bring the COS methods of its gas and electricity services into closer harmony, unless the Company were to depart from the conventional quantity-based allocation framework, including the various definitions of energy, peak demands, and number of customers served.

6.2 Revenue Cost Class (RCC) Ratios

The Company's COS study results are the primary vehicle for determining the overall cost responsibility and price level for the customer classes, within both gas and electricity services. In the case of Centra's services, the class level prices to cover all non-commodity costs are set equal to the cost allocation results. Essentially, all RCC ratios are set equal to 1.0. For MH's electricity services, the revenues and prices are intended to be set at levels that would, over time, bring all classes' RCC ratios within the range of 0.95 to 1.05.

The acceptance of departures of observed RCC ratios from unity, for specific customer classes, and also customer groups and market segments, suggests two things. First, that fully distributed costing (cost attribution methods) cannot identify, for sure, the true cost to provide services, in view of common costs. Second, that fairness and other criteria also weigh into the problem of determining fair and equitable utility rates.

Recommendation. In summary, we generally concur with the Company's current approach: targeted RCC ratios as the primary guideline to set overall price levels for customer classes, given the estimates of cost attribution obtained from COS studies. Moreover, we suggest 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.

7. MARGINAL COSTS

One of the three major objectives of this project was to "Provide recommendations on how or if Marginal Cost adjustments could be made to reflect, or otherwise be reflected in, an embedded COSS."

7.1 Definitions and Context

Marginal cost is the change in costs with respect to a change in the level of output or service being produced or consumed. *Costs* refer to all costs associated with the resource inputs contributing to the production of output, or the provision of services.[24]

In the case of electricity, the production technology involves highly specific, large-scale technologies and processes that involve real-time control of numerous generators, meshed transmission networks, and distribution systems. Electricity cannot be readily stored, and thus the real-time demand for electric service is virtually identical to supply within each moment of time and location. Non-storability also means that inventories cannot serve as a means of arbitrage; such opportunities do not exist. As with other Canadian electricity suppliers such as BC Hydro and Hydro-Quebec, it is energy storage that sets Manitoba Hydro apart from most of the industry. Specifically, major water reservoirs provide the capability to store vast quantities of energy which can be quickly converted into electricity supply, necessary for satisfying the real-time balancing requirements inherent in power systems.

In the case of natural gas, supply technologies involve gas production and transport services (pipeline, transmission, distribution). Importantly, gas supply involves large-scale storage services. Together with production services (commodity gas), storage serves to balance supply with demand which, as in the case of Centra, can have large seasonal variation.

As a practical matter, marginal costs of electricity and natural gas can be organized in parallel with average costs—by function. Estimates of marginal costs of each service, electricity and natural gas, comprise *load-related* and *nonload-related* components.

Marginal costs refer to two general timeframes. Short-run marginal cost (SRMC) is the change in the costs with respect to short-term change in the level of output—usually including only variable production costs,[25] plus line losses in the case of electricity. Long-

[24] This supply-side perspective of marginal production cost has a parallel demand-side perspective: marginal cost is the change in total value realized (foregone) as a result of incremental (decremental) change in consumption.

[25] For MH, water rentals are the major variable cost of generation. Speaking generally, where they are internalized, environmental compliance costs are commonly recognized as variable operating costs.

run marginal cost (LRMC) refers to a timeframe sufficiently long for all resource components (and costs) to adjust to a least-cost configuration.[26]

7.2 Cost Allocation Using Marginal Cost and Tariff Efficiency

Marginal cost-based pricing is generally recognized as the superior approach to obtaining efficient use of resources. Thus, marginal cost, as the basis for prices, fully satisfies the efficiency principle, a main criterion for both COS and the design of retail utility tariffs. In the case of electricity—because of the property of non-storability[27]—marginal costs of integrated retail services can be highly specific to timeframe and location. As a consequence, the pattern of marginal costs by timeframe is sometimes viewed as a viable method to allocate financial costs, where the end result is improved allocative efficiency.[28] Similarly, marginal costs are readily adopted in tariff design, particularly in the context of dynamic pricing, in which prices that reflect current market conditions, covering brief time intervals (hourly or portions of a day) are transmitted to customers at short notice.

7.2.1 Cost Allocation

Forward-looking marginal costs, including long-run dimensions for T&D, can be used directly in the COS process. However, in our view, marginal cost-based allocation (of financial costs) does not, in isolation, necessarily result in improved pricing efficiency, when

[26] To elaborate, marginal costs can be defined as either short-run marginal costs (SRMC) or as long-run marginal costs (LRMC). Short-run marginal cost is the change in variable costs with respect to a change in load. Some costs remain unchanged and are thus referred to as fixed costs, as the timeframe—such as the day ahead—is too short for physical facilities currently in place to be altered or adjusted. In the short run, the capital charges and fixed operations and maintenance costs (FOM) associated with physical facilities do not vary as load varies.

Under LRMC, all costs including capital costs and FOM vary in response to a change in load level. This means that, in the long run, a change in expected load level may (is likely to) precipitate adjustments to physical facilities in order to obtain the desired (least total cost) resource configuration (generation mix). Real-world, long-run adjustments—the implementation of adjustments to obtain the least cost configuration—can take a very long time. The process of implementing long-run adjustments to obtain an optimal configuration is likely to be taking place *as the optimal configuration target is also evolving* in light of new information altering expectations of cost inputs and electricity demands in the future. As a practical matter, then, LRMC is only relevant as a conceptual design: the change in total cost with respect to a change in load if all resources could be adjusted to the optimal configuration *overnight*.

[27] Prospectively, it is quite possible that electricity storage, particularly within delivery systems, will reach a level of scale to be economically viable, in which case cost arbitrage across timeframes may be possible.

[28] Marginal cost-based allocation of financial costs has been advanced before regulatory authorities by Barbados Light and Power Limited, Pacific Gas & Electric Company, Public Service of New Mexico, and Southern California Gas.

compared to conventional allocation methods. Although marginal cost-based allocation may appear to simplify the cost allocation process and place it on a sounder theoretical footing, the approach presents a number of challenges to COS. First, not everyone will agree on the same definition of marginal cost for cost allocation purposes. Second, forward-looking SRMC can vary substantially from one year to the next. Third, use of marginal cost exclusively can lead to over- or under-recovery of financial costs in the absence of adjustments in prices to ensure revenue flows that yield full recovery.

One potential application of marginal cost-based cost allocation is in developing an alternative set of RCCs, for comparison with existing embedded cost-based RCCs. If the utility has flexibility in selecting class RCCs within a range—say, plus or minus 10% of parity—then a marginal cost-based RCC calculation can provide useful guidance regarding the degree to which class prices can depart from parity. While embedded costs may determine the rates that achieve parity level and the range of rates, marginal cost can be used to influence pricing within that range. A broader use of marginal cost might include the use of MC-based RCCs to influence the range of embedded cost-based RCCs.

7.2.2 Tariff Design Implications

As mentioned, allocative efficiency achieved through effective tariffs that make use of marginal costs is a major objective of utility price regulation. It is appropriate for MH to assess the marginal prices facing retail consumers with respect to the marginal cost of providing service. The forward period over which costs are estimated should align with the period over which prices are effective. Thus, for setting static time-of-use prices over, say, the next two years, the appropriate cost metric would be MH's projections of forward-looking opportunity costs of generation coupled with LRMC surrogates for transmission and distribution, as discussed above. Similarly, dynamic hourly pricing in the context of, say, a two-part tariff structure (*forward-spot pricing*), the appropriate cost metric, in hourly frequency, includes estimates of hourly day-ahead opportunity cost of generation (for both energy and reserves), marginal line losses and, potentially, some recognition of transmission in the form an LRMC proxy.

7.2.2 Summary and Recommendations

CA Energy Consulting believes that marginal costs are valuable additions to the COS and rate design process, although we do 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 cost 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.

MH and Centra already either have available or conduct many computations necessary to produce marginal costs for the various functions required to provide electricity and natural gas. Our recommendations below suggest ways to supplement MH's and Centra's current marginal costing applications to provide comprehensive estimates of marginal cost.

1. We recommend that MH and Centra implement a marginal cost-based cost allocation in parallel with the existing embedded cost-based COS approach. It is not clear that, for Centra, marginal cost-based allocation would obtain a cost allocation result significantly different from quantity-based allocation, due to the present marginal cost basis of commodity and pipeline charges.

2. We recommend that electricity marginal costs be further developed in key ways, as follows:
   - Inclusion of prices of reserve services within short-run opportunity costs of generation, based on MISO reserve prices.
   - Application of hourly marginal line losses covering conductors and transformers.
   - Inclusion of 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*.
   - Consideration of applying a private cost of capital metric.

- Use of an economic carrying charge approach for determining the temporal pattern of annual capital charges.

3. Should Centra elect to develop marginal costs for cost allocation or seasonal pricing, we recommend that the marginal cost of natural gas services be further refined, as follows:
   - Development of transmission and distribution cost metrics.
   - Consideration of applying a private cost of capital metric.
   - Use of an economic carrying charge approach for determining the temporal pattern of annual capital charges for transmission and distribution facilities.