PROVINCE OF MANITOBA

BEFORE THE PUBLIC UTILITY BOARD

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Manitoba Hydro	)
Cost of Service Methodology Review	)
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EVIDENCE OF

PAUL CHERNICK

ON BEHALF OF

GREEN ACTION CENTRE

Resource Insight, Inc.

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APPENDICES

I. Identification and Qualifications

Q: Mr. Chernick, please state your name, occupation and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water Street, Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honour society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, integrated resource planning, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking (PBR) and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Appendix PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over two hundred times on utility issues, before regulators in thirty U.S. jurisdictions and five Canadian provinces. My previous testimony is listed in my resume.

Q: Have you testified previously before this Board?

A: Yes. I testified in

- the 2008/09 general rate application (GRA) of Manitoba Hydro ("MH," "the Company" or "Hydro"),
- Hydro's 2008 Energy-Intensive Industrial Rate proceeding,
- Hydro's 2010/11 & 2011/12 GRA,
- Hydro's 2011/12 & 2012/13 GRA, and
- The 2014 NFAT proceeding for Keeyask, Conawapa, US interconnections and related transmission.

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by Green Action Centre ("GAC").

Q: What is the purpose of your evidence?

A: My evidence primarily relates to the principles and methods for cost allocation, including various aspects of the functionalization, classification, and allocation of costs. Since no rates will be based on Manitoba Hydro's current prospective cost of service study (PCOSS14), I do not concentrate on the numeric effect of changes and corrections, beyond indicating the general magnitude of some effects.

I also discuss some issues that affect rate design, to the extent that those have arisen in this process.

Q: What issues do you address?

A: I address various aspects of the functionalization, classification, and allocation of costs in four categories that NSPI defines as functions: generation, transmission, distribution, and retail functions (e.g., billing and customer relations). I also address several issues that do not fall neatly into these categories, such as overheads, line losses, and load data.

Q: How is the remainder of this testimony structured?

A: Section II.A discusses my understanding of the purpose of this proceeding, which then leads into the discussion of the principles of cost allocation in Section II.B.

Section II.C focuses on the issues of allocating the costs of Manitoba Hydro's demand-side-management (DSM) programs, which are of particular concern to GAC. Sections IV, V, VI discuss issues with the functionalization, classification and factor allocation of costs in Manitoba Hydro's three major functions: generation, transmission, and distribution.[1] The final Section deals with lessons learned from this process.

[1] I do not address Manitoba Hydro's fourth function, distribution services, or the overhead and general costs, which Manitoba Hydro functionalizes to the four functions.

A. *Purposes of this Proceeding*

Q: What do you understand to be the purposes of this proceeding?

A: I understand that this proceeding is intended to review the approaches that Manitoba Hydro has used in its current reference cost-of-service study, the Amended Prospective Cost-Of-Service Study for 2014 (PCOSS 2014). Since this PCOSS addresses the loads, costs, and other inputs for a past year, the review in this proceeding is limited to the following issues:

- whether the methodologies are appropriate for use in future rate applications,
- what improvements should Manitoba Hydro make in its approach, and
- what input data and assumptions need to be improved, perhaps by better data-gathering and record-keeping, as well as additional analysis.

The specific values used in any corrected PCOSS14 that Manitoba Hydro may produce as a result of a PUB order in this case are not particularly important; only methods and approaches really matter.

The objective of this exercise is to determine the methods by which Manitoba Hydro will convert accounting data, load data, and other inputs into class cost allocations, generally through a process of functionalization , classification and factor allocation, to produce class allocations.

Q: Please expand on the differences among functionalization, classification and allocation of costs

A: The PCOSS model recognizes four *functions*—generation, transmission, distribution, and what Manitoba Hydro calls "distribution services."[2]

[2] This last category name is confusing, since it includes cost charged to transmission-level customers, costs unrelated to distribution and costs that would not normally be considered "services," like collecting and writing off bad debt. The term "distribution services" is further

Manitoba Hydro functionalizes a portion of each category of general plant and overhead costs to each of those four functions.[3] So far as I am aware, the only potential disagreements about this high-level functionalization of costs are the functionalization of some transmission as generation-related.[4]

Manitoba Hydro's PCOSS14 sub-functionalizes some costs within a function, the most interesting examples of which are as follows:

- Within generation, segregating Brandon coal (which is not used to support exports) from other generation (which is or can be so used).
- Within transmission,
  - segregating 33-kV and 66-kV facilities (sub-transmission) from 115-kV, 138-kV, 230-kV, and 500-kV (which Manitoba Hydro calls just "transmission") facilities,
  - separating out the US ties.
- Within distribution,
  - separating substations, lines, transformers (which are the bulk of what Manitoba Hydro calls "serialized equipment") and services.[5]

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confusing because "services" also mean the lines from the street to the customer, which are functionalized as distribution plant. Other COS studies call this category "customer costs" or "retail costs"; I am not aware of a particularly clear title for this group of costs.

[3]Other COS studies treat overhead as a function, and allocate those costs to classes in proportion to the costs allocated to other functions, or on such drivers as the labor cost incurred by each of the other functions. In this regard, the structure of the COS does not constrain or distort the allocation of overhead costs.

[4] An investment may look like a transmission line, and be recorded on Manitoba Hydro's books as transmission plant, but function as part of generation.

[5] Lines are not subfunctionalized among overhead conductor, underground cable and conduit, and poles, even though those categories are usually broken out in COSSs. Manitoba Hydro does not formally subfunctionalize primary from secondary distribution, but makes an adjustment for the GSL <30 kV, as if secondary were a separate subfunction.

The PCOSS then *classifies* each cost category (i.e., each type of plant and expense) as being driven by one or more of three categories of factors: demand, energy and the number of customers. The most important classification decision in Amended PCOSS14 is the classification of 40% of line costs as customer-related.

Finally, the PCOSS applies an *allocator* (a percentage breakdown among classes) to each cost category. [6] Within each broad type of cost driver, Manitoba Hydro uses multiple allocators for various cost categories, such as class non-coincident peak (NCP) for distribution and sub-transmission and the average of 100 high-load hours for transmission, both as measures of demand. Generation allocators are sometimes differentiated among resources, to reflect the usage of different types of capacity and to retain the benefit of legacy resources for historic loads. Customer allocators are often weighted by the average cost of providing the service to customers in the various classes.

Q: Are the functionalization and classification decisions critical to the class cost allocations?

A: Not necessarily. The cost-of-service study can get to the same final allocation in several ways. For example, the reality that a portion of transmission costs are driven by the need to interconnect remote generation can be reflected by functionalizing a portion of transmission cost as generation (as the PCOSS

[6] Note that allocation is the term normally used for the entire process of assigning revenue requirements to classes, and is also the term used for the last step of that process.

does), classifying a portion of transmission as energy-related, or using a transmission demand allocator with some energy component.[7]

B. *Principles of Cost Allocation*

Q: What guiding principles should the Board apply in reviewing the COSS?

A: While the fundamental considerations could be summarized in many ways, the following list covers most of the important factors:

- The study should serve only as a guide to cost allocation, not as a determinant.
- Consideration of marginal cost and incentive effects should be reflected in rate design. Hence, cost allocation should not generally be driven by concerns about allocation affecting rate design.[8]
- The principal objective of a COSS is the fair and equitable sharing of embedded costs. These terms are subject to multiple interpretations.
- The central touchstone for equity is class contribution to the current and historical causation of costs. Most costs are equitably allocated on the current usage of the equipment and services; some legacy costs are more equitably allocated on past usage.
- Cost of service allocation only splits costs among classes and does not directly determine rate designs or provide price signals to customers. In some cases, providing adequate price signals may require redefinition of rate classes or other changes to the cost allocation.

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[7] Nova Scotia, for example, uses a transmission demand allocator that is a driven about 62% by class energy use and 38% by contribution to its dominant winter peaks.

[8] Occasionally, cost allocation may constrain rate design, by limiting the revenue requirements available to design rates. When those situations are identified, the allocation of revenues among classes may be modified to allow efficient and effective rate design.

- Cost causation should be assessed by using the most realistic practical analysis of cost drivers. Excessively simplified concepts of cost causation should not be allowed to distort allocation in identifiable ways.
- Costs should be allocated on the best available data.
- Whenever possible, the rules for cost allocation should be consistent among classes.
- Cost causation should distinguish between complementary or alternative investments, which substitute for one another, and incremental investments, which add costs to the system.
- Allocation should strive for geographic equity, treating classes similarly, regardless of the historical accidents of the vintage and design of the system across the service territory. This principle is the cost-allocation corollary of postage-stamp rate design.
- The factors used in the COSS should be derived from straightforward methods that can be revised in the future to reflect changes in customer characteristics, loads, and changes in system characteristics.

Q: Please describe the importance of distinguishing between incremental and complementary investments.

A: Customers receive service at various voltages and with a variety of equipment. Most of the distinctions between types of equipment represent alternative or complementary methods for providing the same service. For example, various feeders operate at 4 kV, 13 kV, or 25 kV, and as overhead or underground construction, depending on load density, age of the equipment and other considerations. While the power flowing from generation to a customer served at 25 kV may not flow over any 4-kV feeder, the 4-kV feeders serve the same function as the 25-kV feeders and (in places in which they are adequate) at lower cost. Serving some customers at 4 kV and spreading the feeder costs among all distribution does not increase costs allocated to the customers served directly from the 25-kV feeders; converting the 4-kV feeders to a higher voltage would increase costs to all distribution customers, including those now served at 25 kV.

On the other hand, some distinctions in voltage level represent incremental investment:

- In some cases, a distribution substation and feeder can bring service to customers that would otherwise be served by an extension of the transmission system at higher cost. However, most customers served at distribution voltages cannot take service directly from the transmission system. Even if a transmission line runs right past a supermarket or housing development, Manitoba Hydro must run a feeder from a distribution substation to serve those customers. Distribution in its broadest sense is thus principally an incremental service, rather than an alternative service, needed by and provided to some customers but not all.
- Similarly, almost all customers who take service at secondary voltage have a primary line running by or to their premises, yet cannot take service directly at primary.[9] The line transformers are incremental

[9]Another way of looking at this relationship is that secondary customers are those for whom providing service at secondary has a lower total cost than providing service at primary. Sharing utility-owned transformer capacity is less expensive than having each building own its own transformer.

equipment that would not be necessary if the customers could take service at primary.[10]

These incremental costs should be functionalized so that they are allocated to the loads that incur them, while each group of complementary costs (such as various distribution voltages) should be treated as a single function and recovered from all customers who use any of the alternative facilities.

Q: How does the distinction between incremental and complementary investments arise in this proceeding?

A: While the PCOSS studies properly treat distribution as incremental to transmission and line transformers as incremental to primary distribution, the PCOSS incorrectly treats the following two costs that are alternatives as if they were incremental:

- The 33-kV and 66-kV transmission lines are lower-cost alternatives to the 115-, 138-, 230- and 500-kV transmission lines, but the PCOSS treats them as an incremental cost and reduces the allocation to the GSL >100kV class for using only the higher-voltage lines, as I discuss in Section V.A.2.
- Distribution poles carrying only secondary lines are less expensive than poles carrying primary. If a customer served by a secondary-only pole had decided to be served at primary instead, the primary pole would have been more expensive and that higher cost would have been allocated to all distribution customers. Secondary poles (unlike line

[10] Some secondary conductors parallel primary lines are incremental to the primary system, while secondary conductors that extend beyond the primary lines are complementary, since they avoid the need to extent primary lines.

transformers and most secondary lines) are lower-cost alternatives to some primary poles, yet PCOSS would treat them as incremental costs, allocating their costs solely to secondary customers, as I explain in Section VI.C. [11]

C. Summary of Recommendations

Q: Please summarize the recommendations you present below, regarding the PCOSS.

A: I reach conclusions on several issues in the PCOSS, as follows:

- The costs of DSM are caused by the need to reduce system costs, not by the existence of the participating classes.
    - Whether costs are more equitably allocated in proportion to system costs or assigned to participating classes (or some mix) should be determined by examining the effect of the DSM program and cost allocation on the classes.
- Generation costs should be allocated on a realistic energy weighting, without a capacity component.
    - Manitoba Hydro should re-examine the prices it uses in the energy weighting and make a recommendation to the Board regarding the

[11] Similarly, a portion of the secondary lines replaces primary lines. If the customers that can be served with secondary poles required primary service, Manitoba Hydro would need to extend the primary lines rather than secondary lines. Hence, a portion of secondary lines are also complementary to the primary system, rather than additive. While Manitoba Hydro does not know how much it spends on secondary plant, the PCOSS credits the GSL <30kV 30% of distribution line cost for using only primary distribution, reflecting the erroneous assumption that secondary lines are all additive to primary, rather than complementary.

    - use of the Surplus Energy Program prices or MISO locational prices by the time of the next GRA.
- Transmission costs related to the AC lines and substations required by the generation stations should be functionalized as generation and allocated as generation.
- Load-serving sub-transmission should be allocated with all other load-serving transmission on the 2CP allocator.
    - Even if sub-transmission were to be subfunctionalized, it should be allocated on a broad coincident-peak allocator, like Manitoba Hydro's 2CP allocator, rather than a non-coincident-peak allocator.
- Distribution line costs are driven by load levels, rather than customer number, and should be classified as demand-related. The so-called minimum-system analyses that other utilities have used to identify supposedly customer-related distribution costs are of no value.
- Distribution substations and feeders should be allocated on a broad coincident-peak allocator, like Manitoba Hydro's 2CP allocator, to reflect the timing of stress on the substations.
- Distribution poles should all be allocated on demand at primary.
- The weighted customer allocator that Manitoba Hydro uses for services should be corrected to reflect the sharing of services by customers on multi-family buildings and a wider range of non-residential service costs.

I also make recommendations regarding efforts to improve Manitoba Hydro's PCOSSs and other efforts going forward, in Section VII.

III. DSM Costs and Related Issues

A. DSM Cost Allocation

Q: How does the PCOSS allocate DSM costs?

A: The PCOSS directly assigns DSM costs based on class participation over ten years (Appendix 3.1, p. 12).

Q: What are the relevant considerations in the allocation of DSM costs?

A: DSM has three effects on the revenue requirement that will be recovered through rates. First, DSM shrinks the size of the pie of non-DSM costs that have to be split up, because Manitoba Hydro will need less generation, transmission and distribution, and will be able to earn some export revenues to offset the costs it already has. Since Manitoba Hydro will generally undertake DSM only if it is less expensive than the avoided costs, the total pie shrinks, at least in the long term.

Second, a program that reduces the loads of one class shrinks its share of the cost pie, increasing other classes' shares of the pie. For the participating class, both the reduction in the size of the pie and the class's share of the pie reduces customers' cost allocation. But for some other class, the increase in its share of the costs may be either larger or smaller than the effect on the size of the total pie, so its cost allocation may either rise or fall due to the DSM.

Thus, cost-effective DSM, with the costs allocated to classes based on the class share of the system benefits, can result in non-participating classes paying more than they would without the DSM. Conversely, assigning the costs directly to the participating class(es) can result in the participants paying more for the DSM than they gain from the shrinking of the pie and of their share, leaving them worse off.

These are extreme situations. With highly cost-effective programs and broad participation, all classes are very likely to benefit from the DSM, no matter how the costs are allocated. But the net benefits can be inequitably allocated.

Q: Are the cost effects of DSM the same in the short term as in the long term?

A: No. The costs of DSM are incurred when the programs are designed and implemented, while the benefits stretch on for many years. In 2018, the customers will be paying roughly the costs of the 2018 program, while receiving the benefits of DSM investment stretching over the previous decade or more.

Q: What causes DSM costs?

A: DSM costs are caused by the opportunity to reduce total costs to consumers. For most costs, Manitoba Hydro's revenue requirements would be lower if customers did less to require Manitoba Hydro to incur those costs. Customers whose load growth requires upgrades to their service drops and transformers, extension of three-phase primary distribution, and retention of more hydro energy that could have been exported would increase costs to the system. The same is true for customers who want their service drops underground for aesthetic reasons. Other customers should not bear those costs, so the costs are assigned or allocated to the participating class and billed (more or less) to the customer demanding the service. If customers do not want to pay the costs, they should not increase their load or request more expensive services.

Unlike other costs, DSM costs produce benefits for the participating class and entire system. Manitoba Hydro and the PUB do not want to discourage participation in DSM, and recognize that there are benefits beyond the participant.

Q: Does Manitoba Hydro agree with your observations?

A: In part, yes. Presented in the May workshop with this analysis of DSM cost allocation, Kelly Derksen said "I think that's fair" (Tr. 666, lines 1–2).

Unfortunately, Ms. Derksen went on to say that

> The golden rule of cost allocation is cost causation. And those who cause the costs should pay for the cost. So it's a little bit difficult, at least in that very theoretical or that very traditional view of cost allocation,… you believe those are the customers who cause the Utility to incur them, it's sort of difficult in that mindset to…share it with a much broader base of customers. (Tr. 666, lines 3–13)

Ms. Derksen discussed her concerns with allocating DSM costs at some length:

> We allocate DSM expenditures on the basis of class participation because it's, from our view, the most cost causal approach. It aligns the cost of the programs with the classes that participate in those programs. And it places cost responsibility with those who cause it and can influence it.
>
> And if there was such a thing as cost allocation school, the first thing that you would learn is that, to the extent reasonable and practical, you can directly assign a cost to a customer or a group of customers. That's sort of the golden rule that we operate under. And so it's the superior cost allocation treatment.
>
> [But] there is also a good argument to be made or that could be made that DSM may be viewed as a substitute for generation and transmission. And possibly also for distribution. And one then, from a cost allocation perspective, could say,…you would take the cost [of] DSM and you would allocate it…in proportion to those resources that it is a substitute for.

> …if that's the preferred view in terms of treating DSM expenditures, you're moving off of cost causation. And it becomes…a policy decision. The policy decision is because everyone benefits, all customers benefit, notwithstanding the specific customers that partake in the programs themselves, but because all customers benefit from the fact that you're able to defer generation and transmission. That's a policy decision, and it's a non-cost causal, at least in the mind of a cost analyst. So it just has to be recognized as that. Manitoba Hydro's perspective has been, and continues to be that it's theoretically, from a cost allocation perspective, superior to allocate costs based on class participation, based on cost causation, because it best aligns those who partake in the programs with their [DSM costs]. …the costs and benefits over the long-term are better aligned through direct allocation as we do today. (Tr. 645-649)

Q: Would allocating DSM costs in proportion to its benefits violate central tenets of cost causation and the first rule of allocation school?

A: No. Ms. Derksen's "very theoretical or…very traditional view of cost allocation" does not recognize that DSM benefits the system and that customers participate in the DSM programs because Manitoba Hydro asks them to, for the benefit of the province.

Even though she acknowledges that DSM by one class provides benefits to all classes, her rigid view of cost causation does not reflect those benefits. In reality, most cost allocation decisions reflect how the various classes benefit from an expenditure, by using generation, transmission and other services.

Her preference for allocating "costs based on class participation, …because it best aligns those who partake in the programs with direct allocation" is tautological. Allocating costs to participating classes is the definition of direct assignment.

Ms. Derksen's fundamental confusion on DSM cost allocation arises in the statement that her approach "places cost responsibility with those who cause it and can influence it."[12] Direct assignment of a cost to the class that causes it is equitable where the expenditure benefits only that class, such as direct-assigning streetlighting equipment to the streetlighting class, or direct-assigning meter costs. But Manitoba Hydro does not invest in residential DSM solely to benefit the residential class, or in commercial DSM solely to benefit the GSS and GSM classes. Charging one class for the costs of a program implemented on its properties, but justified by the benefits to all classes, would be inequitable.

Q: Does the PCOSS reflect both the costs and the benefits of some activities?

A: Yes. For example, the PCOSS allocates the costs of late payments to rate classes, but also the revenues from late fees; as well as the costs of electric inspections and the revenues from those inspections.

Q: Could the PCOSS allocate the benefits of DSM to participating rate classes, to offset the costs allocated to them?

A: In principle, that would be a reasonable approach to balancing the costs and benefits of DSM in the PCOSS. In practice, it would be difficult. The cost savings in FY2018, for example, will result from DSM expenditures back to the beginning of the Power Smart program, and relatively little from the FY2018 activities. Determining the load reductions in 2018 from those prior years' programs, the cost savings from the load reductions and the class

[12] Ms. Derksen may be suggesting that charging the residential class for residential DSM would encourage residential customers to "influence" those costs by refusing to participate in cost-effective programs. While Ms. Derksen seems to be confusing cost allocation, rate design, and DSM program design, I doubt that other departments of Manitoba Hydro, or the PUB, wish to "influence" customers to minimize DSM costs.

responsibility for those savings would all be complex. Alternatively, Manitoba Hydro could credit each class with the forecast avoided costs, which raises similar concerns, as well as the fact that the avoided costs would be mostly outside FY2018.

Q: How do you recommend that DSM costs be allocated in future PCOSSs?

A: The allocation of DSM costs should reflect both the system benefits from DSM and the benefits to the participating classes. I recommend that Manitoba Hydro estimate the effects of recent or planned DSM on revenue requirements for each class, for alternative allocations. This analysis would include the long-term annual revenue requirements for three cases:

1. Actual and/or planned DSM spending and load reductions, with DSM costs assigned to the participating classes and system revenue requirements allocated roughly as they would flow through the PCOSS.
2. Actual and/or planned DSM spending and load reductions, with DSM costs allocated in proportion to avoided costs (using weighted energy or other allocators reflecting the composition of avoided costs), and system revenue requirements allocated roughly as they would flow through the PCOSS.[13]
3. No DSM, resulting in higher loads, higher energy costs, lower export revenues, and higher T&D costs (if Manitoba Hydro can estimate the effect of DSM on T&D revenue requirements).

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[13] Other approaches to allocating DSM costs widely across classes would include allocation of DSM costs to exports (or using net export revenues to pay for DSM), which would effectively allocate DSM costs on the system costs that the export revenues would otherwise offset, or to allocate DSM costs on an equal cent/kWh basis and recover them through a systems benefit charge.

The difference between Case 1 and Case 3 would show the effect on rate classes of assigning DSM costs by class, and the difference between Case 2 and Case 3 would show the effect on rate classes of allocating DSM costs in proportion to the system benefits.

Based on that analysis, the Board would be able to select an allocation approach that is fair to all classes, to avoid a situation in which one class is paying for its own DSM efforts that are disproportionately benefiting other classes, or conversely, paying for DSM for other classes are receiving little of the benefit.

B. Net Metering

Q: Why are your testifying with regard to net metering?

A: Net metering (and more broadly, charges and payments to customers with distributed generation, particularly photovoltaics) is a rate design and resource-planning issue, rather than a cost-allocation issue. I address this issue only because Board Member Gosselin asked about net metering in the May 13 workshop and received some input from Manitoba Hydro and Christensen (Tr. at 892–897).

Specifically, Board Member Gosselin seemed concerned about two issues:

- whether net-metering customers should be charged for the infrastructure used by those customers in providing power to Manitoba Hydro, and
- the difference between crediting net-metering customers for the power they deliver to the system and "not paying the DSM user who generates savings for Manitoba Hydro" (Tr. at 895).

Q: Should net-metering customers be charged for the infrastructure used in providing power to Manitoba Hydro?

A: Not unless the net-metering power requires some upgrade to the distribution system. Power delivered by customers will tend to reduce the loading on line transformers, feeders, substations and the transmission system, as well as providing energy that Manitoba Hydro can export. If the equipment is in place to serve load, running some portion of it in reverse for net metering will generally not increase capital requirements. In addition, the energy injected into the system in proximity to load will tend to reduce line losses.

Q: Board Member Gosselin asked about whether a large solar facility, selling power to Manitoba Hydro as a non-utility generator, would be charged for the use of existing infrastructure paid for by other customers. What is your understanding of how this issue is generally handled?

A: In general, power producers selling to the utility do not pay for the use of the existing system. Each such producer is generally required to pay for any incremental costs, both for its interconnection with the utility and for any system improvements that are required by the change in power flows due to the facility. In the case of a typical net-metering customer, the interconnection would already exist and the effect of any power delivered to the Manitoba Hydro distribution system would be to reduce flows, so upgrades would be minimal.[14] Since the existing system is capable of serving

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[14] Any customer with generation behind the meter is usually required to provide protective equipment as needed for the safety of utility workers during an outage on the customer's feeder. Sometimes distributed generation confuses the utility's sensors that detect short circuits in the line, requiring addition of sensors.

the customer's load, any distributed generation installation smaller than that load is unlikely to require additional distribution capacity.

Q: Can you describe the difference in compensation between DSM participants and net-metering customers?

A: Yes. A DSM program participant saves energy (and perhaps demand charges) for all the energy it saves. The participant's compensation consists of the reduction in its energy use, times the retail rate. In addition, the DSM program will usually pay part of the cost of the participant's efficiency measures, or otherwise help reduce the cost of achieving the savings.

A net-metering customer also reduces its energy use for some of the energy it produces.[15] For those kilowatt-hours, the net-metering customer would be compensated just like a customer who reduced usage with DSM. But the net-metering customer also generates some energy that happens to exceed its consumption in some hours, resulting in energy flowing back to the Manitoba Hydro distribution system. Net metering compensates those customers for the energy they deliver to the system.

In each situation, the participating customer receives two financial benefits. DSM participants benefit from bill reductions for reduced usage and from the program incentives, while net-metering customers benefit from bill reductions for reduced usage and from a credit for power returned to Manitoba Hydro.

Q: How should the credit for energy delivered to Manitoba Hydro be determined?

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[15] Since billing demand is determined by the customer's highest use any time in the month, renewable distributed generation installations are unlikely to have much effect on the customer's billing demand.

A: Net metering is a simple way of compensating customers for that benefit to Manitoba Hydro and other customers, but it should be reasonably related to the value of the energy for Manitoba Hydro, ratepayers, and Provincial energy goals. The benefit of distributed solar installations, for example, includes the following components:

- Freeing up energy for export.
- Delay the need for the next generation addition (such as Conawapa).
- Reducing loads on the transmission and distribution system, which
  - reduces losses,
  - reduces the need for upgrades on summer-stressed substations and feeders, and
  - extends the life of transformers and lines (especially underground cable and summer-peaking overhead lines, which are subject to heat-related deterioration).
- Increasing the firmness of energy supply, since droughts will not tend to reduce solar output.
- Reducing the use of fossil generation, including Brandon coal.

With Manitoba Hydro's low current rates, the high value of clean exports, and the high cost of Conawapa, these benefits almost certainly exceed the retail rate credit for net metering.

Q: When the Board takes up rate design issues, how should it approach net metering?

A: Either in the next GRA or in a separate proceeding, the Board may wish to determine the benefits of solar and other net-metering technologies, to determine whether the net-metering credit is a reasonable proxy for the system benefits of energy delivered to the distribution system. In the meantime, the net-metering approach appears to be reasonable.

IV. Generation

Q: How does Manitoba Hydro classify and allocate generation costs?

A: The PCOSS classifies generation costs (including related transmission) as energy-related and allocates the costs to classes in proportion to weighted class energy use.[16]

Q: Do you agree that essentially all of hydro and fossil rate-base costs are driven by energy?

A: Yes. The Manitoba Hydro system is energy limited, needing firm energy earlier than it needs additional peak capacity to meet demand. In the NFAT proceeding, Manitoba Hydro's forecasts showed a need for additional firm energy supply—on top of firm hydro supply, continuous maximum thermal output year-round, and opportunity imports—about four years before the need for additional peak capacity.

Even for systems in which the amount of required capacity is largely determined by peak demands, the cost of the capacity is largely determined by the efforts to reduce the cost of supplying energy, including building hydro plants rather than fossil-fuel plants, and building coal rather than oil- or gas-fired peaking plants. In the NFAT proceeding, Manitoba Hydro estimated that Keeyask would cost $6.5 B for 695 MW (PUB final report, at

[16] The costs of the Brandon coal plant, which Manitoba Hydro will not use to support exports, are allocated only to domestic classes.

119–120), or about $9,400/kW, versus $770/kW for peaking turbines (ibid, at 129). Hence, peak demand alone, even if it were the driving factor behind generation acquisition, would require only about 8% of the capital costs of Keeyask.[17]

Q: How does Manitoba Hydro propose to allocate the energy-related cost of generation?

A: For several years, the PCOSSs have allocated energy-related generation costs on a value-weighted energy allocator. Manitoba Hydro estimates the relative value of the energy in each of 12 annual periods (peak, shoulder and off-peak for four seasons) from the prices it charged for energy in the Surplus Energy Program (SEP) in those periods over several previous years, adjusted for inflation.[18] Manitoba Hydro uses these prices to reflect the lost export revenues or additional energy costs that result from customer usage

In Amended PCOSS14, Manitoba Hydro varies from its past practice by including a demand-related capacity cost in the weighting of the peak periods.

> Manitoba Hydro notionally classifies all Generation costs as Energy-related, with costs allocated on the basis of energy consumption weighted by the relative market value of energy in each of twelve time periods to reflect Demand. CA recommends that Manitoba Hydro explicitly incorporate capacity costs…in its marginal cost-weighting factors. (Submission, §7.2.2)

[17] This computation is similar to the Equivalent Peaker Method suggested by Christensen (Appendix 5 at 12) and discussed by Manitoba Hydro (Appendix 4 at 7–8). The fuel costs and environmental effects from a peaker that operated only a few hours annually would be very small.

[18] In Amended PCOSS14, Manitoba Hydro uses price data from April 2004–March 2012. I assume that Manitoba Hydro would propose to use weights for PCOSS17 based on prices from April 2004–March 2016.

> Manitoba Hydro has reflected an additional capacity component in its Weighted Energy allocator by utilizing the value of capacity as represented by the Reference Discount used in the Curtailable Rate Program (CRP) in the weighting factors. (Appendix 1 at 7)

In other words, while Manitoba Hydro functionalizes and classifies generation as energy-related, it reverses direction at the allocation step.

The capacity adder is $1.89/MWh in the peak periods for all four seasons, based on an assumed price of capacity at $37.92/kW-year in 2012 dollars. Manitoba Hydro acknowledges that "The CRP reference discount incorporated in the weightings is well in excess of current market prices for capacity" (Appendix 1 at 7), and does not explain why it used that overstated capacity price for allocating energy costs.

Manitoba Hydro applies this adjustment retrospectively to 2005, including several years that Manitoba Hydro had previously used without a capacity adder.

Q: What is Manitoba Hydro's rationale for including the demand-related capacity in the energy allocator?

A: Manitoba Hydro's explanation is scattered through various documents, including the following:

> Due to changes in market conditions, the capacity component of energy supply may no longer be adequately reflected in the differential between on peak and off peak energy prices. (Submission, §7.2.2)

> [Christensen] recommends that Manitoba Hydro include capacity cost as well as operating reserves in its marginal cost-weighting of energy consumption for purposes of generation-related cost allocation. CA concludes that implicit capacity costs in energy market prices are highly variable and may not adequately be captured in the differential between peak and off-peak prices.

> …due to changes in market conditions, the capacity component of energy supply may not be adequately reflected in the differential between on-peak and off-peak energy prices. (Appendix 1 at 7)

> In view of recent developments in the structure of MISO wholesale markets—namely, the appearance of voluntary capacity markets—capacity costs should also be considered for inclusion in MH's weighted energy calculations. Prior to the appearance of MISO capacity markets, capacity costs were accounted for, arguably, by the scarcity rent content implicit within observed energy prices. (Appendix 2 at 18)
>
> MISO capacity auction prices are currently low and reflect very limited participation, suggesting that, since 2009, scarcity rent content is similarly small, even in the absence of capacity markets over much of this period. (Appendix 2 at 20)[19]
>
> Manitoba Hydro has incorporated a capacity adder based on the advice provided by Christensen Associates that capacity may not sufficiently be reflected in energy price differentials on a go-forward basis. CA identified the establishment of a voluntary capacity market in MISO in 2009 as the time that market conditions changed…The perspective provided by CA was developed through an examination of the market conditions that contributed to the on/off peak differential, and not through observations of the changes in price differentials. None the less, an initial comparison of the ratio of on-peak to off-peak prices in the pre- and post- 2009 timeframes would appear to support the argument that the pricing relationship changed with the introduction of the VCA in MISO….
>
> However, higher on-peak prices can reflect both the higher variable cost of generation resources used to meet peak demands, as well as scarcity rent content. Since the changes in MISO markets largely coincided with the 2008 economic downturn and drop in natural gas prices, the changes in the on/off-peak ratio cannot be reasonably attributed entirely to a reduction in scarcity premiums. (Coalition/MH-I-56e).

Q: Are Manitoba Hydro's arguments for including generation capacity costs in the energy weighting factually correct and logically consistent?

[19] I do not fully understand Christensen's point here, since the MISO capacity market has existed since 2009. Perhaps their point is that MISO has sufficient capacity, so there is no scarcity to price in the capacity or energy markets. That being the case, there is no reason to invent a scarcity value to add to Manitoba Hydro's peak-period energy weightings.

A: No. The purpose of the energy weighting is to apportion to time periods a group of costs that are driven by energy requirements. Those costs are not driven by capacity requirements.

The only evidence that Manitoba Hydro offers to demonstrate that the MISO capacity market has somehow eroded the peak-period energy costs, requiring an adjustment to the weighting approach, is a pair of tables in Coalition/MH-I-56 c and e, showing the ratio of MISO on- and off-peak energy prices.[20] Manitoba Hydro appears to believe that these data support the idea that the MISO capacity market has somehow stolen some value from the energy market. The first table shows no clear pattern in the ratio of on- and off-peak prices over time, with the lowest ratio (1.35) in 2002/03, before the start of the MISO capacity market. The second table shows that the average ratio in 1999–2008 was higher than the average ratio in 2009–2014. As Manitoba Hydro notes, this decline coincided with the drop in gas prices following the recession and shale-gas boom. Both on- and off-peak prices fell, but the on-peak prices, which more often are driven by gas prices, fell somewhat more.[21] Retirement of coal and nuclear capacity in MISO would also tend to increase the off-peak price, as gas generation would tend to be at the margin more often. There is no evidence that the ratio of peak to off-peak price in the MISO energy market changed due to the introduction of the capacity market.

Q: Is Christensen correct that "MISO capacity auction prices…currently… reflect very limited participation"?

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[20] Manitoba Hydro did not specify the MISO location(s) for which these prices were reported.

[21] Manitoba Hydro concedes this point in Coalition/MH-I-56e, as quoted above.

A: No. About two-thirds of MISO capacity participated in the 2013/14, 2014/15 and 2015/16 auctions, and 75% in the 2016/17 auction. The remaining generation was used by vertically-integrated utilities to self-supply their loads.

Q: If there were evidence to support Christensen's speculation that the introduction of the capacity market had reduced MISO peak prices, would that indicate that a capacity value should be added to the peak weighting?

A: No. If that were true, it would indicate that the SEP prices included a capacity component prior to 2009, and that MISO has now removed that inappropriate value from the market prices that drive the SEP prices.

Q: If the Board wanted to reflect the MISO capacity market prices in the energy weighting, did Manitoba Hydro use the correct values?

A: No, for two reasons. First, Manitoba Hydro applies its capacity adder for five years prior to the start of the MISO market, double-counting the putative capacity price for more than half the data used in the weighting.[22]

Second, actual MISO capacity prices have been much lower than the $38/kW-year assumed by Manitoba Hydro, as shown in Table 1. The average over the three years of capacity markets actually used in the Amended PCOSS14 was under $15, the average including the zero capacity prices back to FY 2005 is under $6, and the average through FY 2015 would be about $4/kW-year.

[22] The double-counting would affect a little less than half the historical data in the next GRA, if Manitoba Hydro uses data through FY 2015.

Table 1: MISO Capacity Prices for Minnesota ($/kW-year)

2009/10	$43.80
2010/11	$0.14
2011/12	$0.00
2012/13	$0.26
2013/14	$0.38
2014/15	$1.20
2015/16	$1.27
2016/17	$7.20

Q: Has Manitoba Hydro properly computed the marginal energy weights, excluding the capacity value adder?

A: Not necessarily. Since the SEP prices are supposed to reflect short-term projections of the lost value of exports, or the costs of imports or fossil generation in Manitoba, I would expect the MISO prices for the Manitoba connection to be very similar to the SEP prices. To check the reasonableness of the SEP-based energy weights, I computed the ratios of the Manitoba day-ahead prices energy delivered in Manitoba for the MISO market for the periods defined by Manitoba Hydro, in the period January 2009 through March 2012. Even excluding the capacity adder, Manitoba Hydro's SEP-based price ratios are significantly higher than the MISO-based ratios in many periods, as shown in Table 2 and Table 3.

Table 2: SEP and MISO Price Ratios by Period, January 2009–March 2012

	SEP-Based Ratios			MISO-Based Ratios		
Season	**Peak**	**Shoulder**	**Off-Peak**	**Peak**	**Shoulder**	**Off-Peak**
Spring	2.740	2.635	1.519	2.176	2.053	1.177
Summer	3.224	2.427	1.000	1.735	2.489	1.000
Fall	2.845	2.459	1.324	2.225	2.018	1.067
Winter	3.899	3.146	2.324	2.807	2.628	1.716

Table 3: Comparison of SEP and MISO Price Ratios

Season	Peak	Shoulder	Off-Peak
Spring	26%	28%	29%
Summer	86%	-2%	0%
Fall	28%	22%	24%
Winter	39%	20%	35%

Manitoba Hydro may have some reason to believe that the SEP data (which largely reflect Manitoba Hydro's expectations of MISO prices) are more appropriate indicators of the relative value of energy by period than the actual MISO data. This cost-of-service review process has been too hurried to cover all the issues raised, including this one, so the reliance on SEP data to calculate the energy weights should be re-examined in Manitoba Hydro's filing in the next GRA.

Q: Please summarize your observations regarding the allocation of generation costs.

A: Generation costs should be classified as energy and allocated on an energy allocator that reflects the relative value of energy by time period. The costs of new generation capacity should not be included in that weighting, and the energy weightings should be reevaluated in light of large differences between the pattern of SEP prices and the pattern of market prices reported by MISO.

V. Transmission

Q: What transmission issues do you address?

A: I have three concerns with the treatment of transmission in Amended PCOSS14:

- inadequate functionalization of transmission to generation,[23]
- the subfunctionalization of sub-transmission,
- the choice of the transmission demand allocator.

[23] As I discuss in Section II.A, the same consideration may be reflected in classification or allocation. For simplicity, I will assume that the use of transmission to connect generation will be dealt with through functionalization.

Q: What are the uses of plant that is carried on Manitoba Hydro's books as transmission assets?

A: The uses of transmission equipment include the following:

- creating a network that can move power around from many sources to many delivery points (to either ,
- connecting generation to that network,
- connecting radial load to the network, and
- allowing imports and exports.

Q: When do Manitoba Hydro's transmission lines and substations experience their peak loads?

A: Manitoba Hydro was not able to provide any such data (GAC/MH I-7, GAC/MH I-8).

A. Functionalization

1. Generation-related Transmission

Q: Why are some transmission assets appropriately functionalized (or classified or allocated) as generation-related?

A: Substations and transmission lines are required to tie generators into the general transmission network, especially for generation that is remote from the load centers (such as most of Manitoba Hydro's hydro facilities). In addition, decisions about generation siting to minimize generation costs (e.g., construction of large centralized plants, concentration of hydro facilities in the best locations) require reinforcement of the transmission system to accommodate injection of large amounts of power into relatively few locations on the network.

Q: What transmission assets does Amended PCOSS14 functionalize as generation?

A: The PCOSS includes as generation-related only the HVDC lines and converters and the northern AC collector system that brings power from Limestone, Kettle and Long Spruce to the Henday and Radisson converter stations.

Q: Are other Manitoba Hydro transmission assets generation-related?

A: Yes. I have identified two categories of such assets. First, Manitoba Hydro agrees that some generation feeds should be functionalized as generation, but Manitoba Hydro has not bothered to do so. (Tr. 487, 497, 607) These appear to include the facilities shown in Table 4, drawn mostly from GAC/MH-6.[24]

Table 4: Manitoba Hydro-Designated Generation Feeds

Stations		**Total Cost**
	PtB/SlaveFall Switching Station	1,149,828
	Wuskwatim Sw. Stn	3,508,945
Lines		
GP-1	Great Falls-Pine Falls115 kVAC T/L	34,573
S1-S2	Slave Falls to Scotland 115 kVAC T/L	424,752
PR-2	Pine Falls-McArthur 115 kV AC T/L	14,523
R1-R2	Slave Falls to Pointe du Bois 115 kVAC T/L	65,733
B78-S	St Leon - Bison Wind 230 kVAC T/L	2,972
J89L	St. Joseph - Letellier 230kV AC T/L	140,421
W1,W2,W3	Wusk GS-Wusk Sw Stn 230kv Collector Line	222,044

Second, Manitoba Hydro has decided to functionalize as transmission some facilities that were explicitly built for generation, and serve primarily to bring power from generation to the network. Manitoba Hydro's totally arbitrary functionalization rule is that, so long as *some* power would flow

[24] The "Wuskwatim Generating Station to Wuskwatim Switching Station 230kv Collector Line" and the Wuskwatim Switching Station in the "Cost Details Transmission and substation" spreadsheet are clearly also a simple generation feed and interconnection, so I included those in Table 4.

through a transmission facility without the generator being in service, then it is part of the network transmission. (Tr. at 484, 609–611)[25] In Manitoba Hydro's approach one electron flowing through a facility magically transforms it from a generation feed to network transmission.

Manitoba Hydro's failure to treat as generation facilities built and used to connect generation, that would never have been built, except for the need to connect the generation, flies in the face of Manitoba Hydro's claim to follow cost causation principles.

If a line was built to connect generation, but is now essential for connecting customers to the grid, its cost may reasonably be treated as load-related, or a mix of generation and load. But if the line was built to connect generation, and is still required only by that role, its cost should be treated entirely as generation-related.

Q: Which generation-connection facilities has Manitoba Hydro functionalized at transmission, under its "one-electron" rule?

A: The most important such facilities are associated with Wuskwatim. In 2007, Manitoba Hydro described the Wuskwatim project as requiring the construction of four transmission lines and a substation.

> In addition to the Wuskwatim Generating Station itself, the plant will require new transmission lines and substations to deliver electricity into Manitoba Hydro's existing transmission system. The points of connection will be at the new Birchtree Station in Thompson; at the existing Herblet Lake Station; and at the existing Rall's Island Station in The Pas.

[25] Alternating-current power flows over the path of least resistance, regardless of whether that path is needed for the flow.

> One 230-kV transmission line is required between Wuskwatim and Birchtree; two 230-kV lines between Wuskwatim and Herblet Lake; and one 230-kV line between Herblet Lake and Rall's Island. (Annual Report (56th Annual Report at 37)

The Manitoba Hydro web site also lists these lines as part of the Wuskwatim project. The lines were not required to connect load, only to connect Wuskwatim, as Manitoba Hydro agreed (Tr. 609–610) These three lines alone are 30% of the rate base ($146 M out of $480 M) and 20% of the annual cost for the transmission listed in the "Cost Details Transmission and substation" spreadsheet, excluding the HVDC lines and collectors.

Similarly, the Manitoba Hydro web site lists transmission lines as part of each generation project, as summarized in Table 5, other than Brandon or Selkirk. Table 5 excludes Wuskwatim, which I have already discussed, and the northern collector lines that Manitoba Hydro includes in generation.

Table 5: Transmission Lines Associated with Generation, as identified on Manitoba Hydro web site

Generator	Voltage	Lines	Destination	Apparent Function	Annual Cost Generation
Pine Falls	115	1	Great Falls GS	Generation	34,573
	115	1	McArthur GS	Generation	14,523
	115	2	Parkdale	1 Load, 1 generation	28,823
	115	2	Manitoba Paper	Can't identify on map	
	66	1	Grand Beach	Load	
	66	1	Lake Winnipeg	Load	
Grand Rapids	230	2	Winnipeg	1 Load, 1 generation	96,704
	230	1	Thompson	Load	
	230	1	Overflowing River	Load	
	230	1	Dauphin	Generation	322,412
Great Falls	115	4	Pine Falls, Selkirk, and Winnipeg	1 Load, 1 double-counted, 2 Generation	147,024
	66	1	nearby mines	Load	
Jenpeg	230	1	Ponton	Generation (if 66 kV could serve Cross Lake)	245,285
Kelsey	138	2	Thompson	1 Load, 1 Generation	95,171
	138	1	Split Lake	Load	
	138	2	Gillam	Load	
Laurie River	138	1	Thompson	Load	
	230	1	Ponton to Thompson	Load	
	230	1	Wuskwatim-Birchtree	Wuskwatim transmission	
McArthur	115	1	Pine Falls	double-counted	
	115	1	Seven Sisters	Generation	23,650
Pointe du Bois	66	4	Rover Avenue	1 Load, 3 Generation	179,012
	138	2	Slave Falls	Generation	65,733
Seven Sisters	115	5	Winnipeg	All needed for Ontario ties?	
	115	1	Whiteshell		
	115	1	Kenora, Ontario	Ontario tie	
Slave Falls	138	2	Scotland Ave	Generation	424,752

In Table 5, I provide my best estimate of whether each of these lines is generation-related. I treat lines that are necessary to serve distribution substations as transmission and any additional lines along the same routes as generation-related. I assumed that one line each between the Winnipeg area Pine Falls and Great Falls would be needed to serve Black River, Bissett, Manigotagan, and substations to the north of Manigotagan, even though one of those 115 kV lines might be sufficient to serve the 66 kV system.

These lines account for $1.7 M of annual costs. In addition, the Radisson-Kelsey 230 kV line ($0.3 M annual cost) is clearly required by the northern generation (it parallels a 138 kV line that appears and some of the lines from the Brandon generating station were almost certainly required by that plant.

Q: Are some Manitoba Hydro transmission-voltage substations more properly functionalized as generation than transmission?

A: Yes. Manitoba Hydro clearly identified the $50M Birchtree substation as part of the Wuskwatim project, but did not count it as generation-related.[26] The switching stations at Wuskwatim, Kelsey, Pointe du Bois, Slave Falls, McArthur Falls, and Seven Sisters appear to be entirely or mostly generation-related.[27] The Brandon, Pine Falls and Great Falls switching stations also appear to have generation-related portions that would not be needed without the power plant, but I do not have enough information to identify those portions. The same is true for the stations that receive the power from remote generation in the Winnipeg area, such as Rover, Rosser, La Verendrye and the AC portions of Dorsey.

Q: Please summarize your observations on the functionalization of transmission assets to generation.

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[26] Part of the station costs at Rall's Island and Herblet Lake may also be related to integration of the Wuskwatim transmission lines.

[27] While Pointe du Bois connects to both 66 kV and 115 kV lines, the Bird Lake and Bernic Lake distribution substations served at 66 kV from Pointe du Bois could have been served by a single 66 kV line from the Winnipeg area (which I treated as transmission in Table 5).

A: A substantial portion of the AC transmission investments beyond the northern collectors was required by, and primarily serve, the role of interconnecting specific generation resources to the transmission network. Those include the facilities that Manitoba Hydro agrees are generation related (as listed in Table 4), the Wuskwatim 230-kV lines, other lines identified as part of generation projects and not needed for other purposes (as in Table 5), the generator switching stations and a portion of the costs of the Winnipeg-area stations that receive the power from remote generation. These corrections would shift at least $17 M in annual revenue requirements from the 2CP transmission allocator (and a small amount from the NCP substation allocator) to the weighted energy allocator for generation.

2. Sub-Transmission Subfunctionalization

Q: How does Manitoba Hydro determine the separation of subtransmission from transmission?

A: Amended PCOSS14 designates 33- and 66-kV lines, and the transformers and low-voltage equipment at substations that step down to those voltages, as sub-transmission.

Q: What is the practical effect of Manitoba Hydro's decisions regarding allocation of sub-transmission?

A: Manitoba Hydro does not allocate any share of subtransmission to the General Service Large class served at voltages over 100 kV.

Q: What is Manitoba Hydro's rationale for dividing the 33- and 66-kV subtransmission from the >100kV transmission system for cost allocation purposes?

A: The PCOSS says that "These facilities are required to bring the power from the common bus network to specific load centres" (PCOSS14 at 23), "Subtransmission costs are incurred in order that the necessary facilities are available to meet the non-coincident peak demand at the secondary level" (PCOSS Schedule E6), and "Use of the facilities by the rate class (i.e. the loads of large industrial customers who receive service at the Transmission level are excluded from the allocation tables used to allocate Subtransmission…facilities)." (PCOSS 14 at 63)

Q: Is this differentiation appropriate for cost-allocation purposes?

A: No, for the following four reasons:

- The Company's transmission system is a single, unitary system, with the various voltages providing complementary, not incremental, services.
- If Manitoba Hydro were to exclude the costs of the <100-kV equipment from the cost of service for the >100 kV industrial load, equity demands that the Company recognize that a substantial portion of the distribution load also does not use <100-kV facilities for power delivery.[28]
- Some generation (Laurie and Pointe du Bois) is connected through <100-kV transmission. A share of <100-kV transmission thus serves all load, regardless of the transmission levels to which the load is attached.[29]

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[28] Only part of the GSL load uses the subtransmission system directly for delivery of power, and Manitoba Hydro charges only that portion of the load for subtransmission. Only part of the residential load (or GSS, or GSM) uses the subtransmission system directly for delivery of power, yet Manitoba Hydro allocates subtransmission system costs based on all residential load. If subtransmission not allocated as part of the total transmission system, the same allocation rules should be applied to allocation to all classes.

[29] These facilities should be treated as generation-related and thus allocated to all domestic firm customers on energy, as I explain in Section V.A.1.

- Arbitrarily allocating certain transmission voltages to a subset of classes is inconsistent with the approach to dedicated transmission radial taps in Amended PCOSS14. Manitoba Hydro allocates those taps, which serve only one class, to all classes, averaging all transmission over all customers.

Q: Please explain why Manitoba Hydro's transmission and subtransmission facilities make up a single, unitary system.

A: The <100 kV (33-kV and 66-kV) and the >100 kV (115-kV, 138-kV, 230-kV, and 500-kV) lines and substations are complementary parts of a single system, since they cover different areas.[30] If not for the <100-kV lines, additional transmission >100 kV would have to be added. In other words, the <100-kV equipment represents an economic alternative to higher-voltage transmission, rather than an incremental cost.

For example, Manitoba Hydro built a 230 kV loop from the Winnipeg area north to the Silver substation (and only that one substation) near Arborg, then west to join the main 230 kV line from Grand Rapids and the northern hydro plants.[31] A similar loop, but at 66 kV, runs from Pine Falls, through Black River, Manigotagan and Bissett, back to Great Falls. If the loads on those three distribution substations (and the four substations served by a branch off the loop, north of Manigotagan) were higher, Manitoba Hydro would have needed to upgrade the loop to 115 kV or even 230 kV. The loads

[30] The transmission map provided in GAC/MH-I-1 does not show subtransmission lines paralleling >100 kV lines in the same way that distribution feeders parallel transmission and secondary lines parallel primary lines, to serve customers who cannot connect at the higher voltage.

[31] While GAC/MH I-1 shows Silver as stepping down only to 66 kV, GAC/MH I-12 lists a 33 kV and two 66 kV transmission lines.

east of Lake Winnipeg have saved Manitoba Hydro substantial investments by not requiring that upgrade. Charging the classes that use those less-expensive lines more than the GSL >100kV class (which requires high-voltage transmission all the way to its meters) is unwarranted and backwards.

Q: Please describe the extent to which distribution load takes power off transmission at various voltage levels.

A: Not all of the distribution load uses the under-100-kV system for power delivery. If the GS Large load that happens to be connected to a 138-kV line is excused from the costs of the 33- and 66-kV lines, the distribution load that is served by a feeder that happens to be connected to a 138-kV line should also be excused from the costs of the subtransmission lines.

Q: Is this effect significant?

A: Yes. According to GAC/MH I-13, there are 96 distribution substations that are fed from transmission over 100 kV. These distribution substations serve 35% of distribution load. So equitable cost sharing requires that only about 65% of distribution-class loads be included in the allocation of the sub-transmission costs. The result would shift a significant share of the sub-transmission costs from the distribution classes to GSL 30–100kV. If Manitoba Hydro were to sub-functionalize transmission, must apply the sub-functionalization consistently.

Q: Please summarize your observations regarding the classification of subtransmission costs.

A: The separation of subtransmission is inappropriate in principle and impractical in application. While MH segregates <100 kV facilities in a manner that benefits the GSL >100kV class, a full sub-functionalization of transmission for all classes would reduce the allocation to classes served at distribution. All transmission, from 30 kV up, should be allocated consistently: generation-related facilities on the generation energy allocators, other facilities on the 2CP transmission allocator.

B. *Allocation of Subtransmission*

Q: How does the COSS classify and allocate subtransmission?

A: In the PCOSS14, subtransmission is classified as 100% demand-related and allocated based on class Non-Coincident Peak ("NCP") demands.

Q: How does allocation of subtransmission based on class NCP understate the diversity of load on this equipment?

A: The purpose of subtransmission is to "bring power from the common bus network to specific load centres" (PCOSS14, p. 23). These load centers are likely to include a mix of customers of different sizes, types and load shapes and from various rate classes. Class NCP would be appropriate only if each subtransmission line served only customers from a single rate class, and if all parts of the subtransmission lines in the province experienced their peak loads at the time of the class NCP.

Q: Are these two conditions true for Manitoba Hydro's system?

A: The first condition is certainly not met in Manitoba. While Manitoba Hydro has not been able to provide a map of its subtransmission system, the map provided in response to GAC/MH I-1 shows some of the 66-kV lines.[32] Among the distribution substations served from the 66-kV system east of

[32] A number of substations step down from higher voltages to 66 kV, but GAC/MH I-1 does not show the 66 kV lines or the distribution substations they serve. Examples include Lynn Lake, Minitonas, Ashern, Dauphin Vermilion, Roblin South, Birtle South, Raven Lake, Neepawa South, Carberry North, Saskatchewan Avenue, and Portage South, among others.

Lake Winnipeg is Bisset, which is described as having the following potential loads:[33]

- 130 housing units
- The San Antonio gold mine
- The San Antonio School
- Manitoba Conservation, Regional Operations, Eastern Region, Natural Resources office
- A hotel
- A bed-and-breakfast
- A drilling company
- Several other small businesses
- A water-treatment and supply system
- The base of operations for the Boy Scouts of America and Scouts Canada's Northern Tier High Adventure Base

These customers would include members of the residential and GSS classes, and probably the GSM, streetlighting and unmetered classes. The gold mine may be a GSL customer. The other communities on that 66 kV system also have a variety of loads.

Hence, the peak loads on that 66 kV system, and probably most of the subtransmission lines and substations, are determined not by the non-coincident peak load of any one class, but by the combination of loads of several classes. The NCP allocator is clearly inappropriate for subtransmission.

Q: How should subtransmission be allocated?

A: Subtransmission should be allocated on the same broad summer and winter peak-loads allocator used for transmission (Manitoba Hydro's 2CP transmission factor D14), adjusted to exclude export load. In its Workshop

[33] My information is from Wikipedia and the Manitoba Community Profile for Bissett. Some of these facilities may not have electric service.

presentation, Manitoba Hydro reports the effects of running the COSS with its broad CP allocator, excluding exports and reducing the weighting of summer CP .

VI. Distribution

Q: How does Manitoba Hydro classify and allocate distribution costs?

A: Manitoba Hydro's recent PCOSSs treat distribution costs as follows:

- Distribution substations and line transformers are classified as 100% demand-related and allocated on a class non-coincident peak (NCP).
- Lines and poles are classified as 60% demand-related and 40% customer-related.
- The demand-related portion is allocated on class NCP and the customer-related portion is allocated on unweighted customer number.
- The remaining distribution plant (including service and meters) is classified as 100% customer-related and allocated on weighted customer number.
- The allocation to the GSL <30kV class (the only class served at primary) is reduced by 30% to reflect the fact that these customers do not use secondary equipment. Manitoba Hydro thus effectively sub-functionalizes 30% of distribution costs as secondary.

A. Demand/Customer Classification

1. Manitoba Hydro's Basis for Classifying Lines

Q: What is the basis of Hydro's classification of lines and poles as 40% customer-related?

A: Manitoba Hydro picked the ratio without any supporting data, characterizing it as a “fixed cost separation approach” (Tr. at 764).

Q: What is Manitoba Hydro’s rationale for its classification of poles and wires?

A: In Manitoba Hydro’s conceptual view, the length of wire is customer-related and the size is load-related:

> it's common in industry …to say that poles and wires serve two (2) functions. Number 1 is those poles and wires have to be sufficiently long and big enough to serve a customer. And secondly, … the poles and wires have to be large enough in order to support the load that the customer is attached to. (Tr. at 656-657)

Q: Is Manitoba Hydro’s conceptual view consistent with its understanding of the factors that drive its distribution investments?

A: No. Manitoba Hydro recognizes that lines and poles are added to serve additional load, or for replacement of deteriorated equipment.

> So we'll take into consideration factors such as the existing loading on the system in the area, existing reliability situations, load growth potential, age, the condition of the asset, that type of thing. (Tr. at 687)

Nothing in this discussion of factors driving investment indicates that costs are at all customer-related.

Manitoba Hydro also explained its decision to classify some line cost as customer-related as follows:

> The 60/40 demand and customer split recognizes that the design for poles and wires consider line length and customer density, which are in turn driven by where customers choose to locate, in addition to the load requirements of the customers. Growth in demand can require upgrades however; it is just as likely that such upgrades would be triggered by an increasing number of customers. This treatment recognizes that customer count is a valid cost driver of poles and wires. (IR PUB 1-48)

Q: Is this explanation convincing?

A: No. Manitoba Hydro's position seems to be based on a semantic sleight of hand. The distribution investments are required by rising load, but some of the load growth comes from new customers; therefore, Manitoba Hydro argues that investments driven by load are nevertheless customer-related.

As for the effect of "line length," Manitoba Hydro will not add many new poles and lines to serve hypothetical new customers with zero or minimal load. As explained in PUB/MH-I-33, Manitoba Hydro will pay up to:

- $800 for a seasonal home,
- $1,600 for a "standard" heated home,
- $4,000 for an all-electric-heated home,
- three times the incremental annual gross revenues (at current approved rates).
- Manitoba Hydro describes this last rule as applying to GS customers served at distribution voltage in PUB/MH-I-33, but elsewhere appears to apply the rule more generally, including to residential developments:

> Manitoba Hydro would normally invest up to three times forecast annual revenue to extend service to a customer. For customers served at less than 30 kV, there are additional limitations on the amount Manitoba Hydro will invest in dedicated facilities on private property and in special services such as underground service, seasonal residences, location of point of delivery, three phase service and pad mount transformers. (PUB MFR 18)

Both for the residential allowances and the three-times-revenue rule, Manitoba Hydro bears the costs of connecting to new customers only if the demand and revenues justify the extension.

Q: Has Manitoba Hydro provided the basis for its particular choice of classification ratio?

A: No.

Q: Then what support does Manitoba Hydro offer for this classification?

A: It points to a 1990 evaluation of its cost-of-service study by Ernst & Young (Tr. at 763-764):

> …it was generally viewed by that consultant that the 60:40 split between demanding customer for poles and wires was consistent with their experience in the industry at the time as well as the limitations of data availability with respect to Manitoba Hydro. (Tr. at 763)

Ernst & Young assumed that only two calculation techniques are "accepted" for classifying distribution: the Minimum-System Method and the Zero-Intercept Method. (2010–2012 GRA filing, Appendix 27, p. IV-9).

Manitoba Hydro also cites the more recent review of its COSS by Christensen Associates (Tr. at 764). Christensen views classification of poles and lines as partly customer-related as the proper approach (Appendix 5 at 18), but the Christensen staff conceded in the technical workshop that many jurisdictions treat the distribution system as entirely demand-related and classify as customer-related only the distribution equipment that are directly connected to customers (services and meters) and associated expenses (Tr. at 683–684).

Q: What was the basis of Ernst & Young's evaluation of Hydro's classification of distribution as 40% customer-related?

A: The study (Appendix 27 in the 2010–2012 GRA) surveyed classification approaches from the following sources:

- The consultant's experience with other utilities who had, like Hydro, adopted a "fixed proportion" classification without a study of cost-causation. These utilities assumed wires and poles to be between 30% and 100% demand-related (Ernst & Young, p. IV-5).

- A session with Hydro employees on the design of the Company's distribution system. This discussion does not appear to have led to a clear consensus about the drivers of distribution investment:

> our staff was told by Manitoba Hydro employees that the distribution system is sometimes "designed to serve new customers whether the demand is low or high." This design criterion could justify classifying the cost of lines entirely as customer related. However, the same session resulted in notes identifying the general criteria of voltage drop and expected loads on the system over a 20 year period. (2010–2012 GRA filing, Appendix 27, p. IV-5)

Q: Did the 1990 Ernst & Young Study perform any analysis to support Hydro's distribution classification, for example, by using a minimum-system approach?

A: No. Ernst & Young found that Hydro did not have the data required for a cost-causation analysis of its distribution system (2010–2012 GRA filing, Appendix 27, p. IV-10). Instead of a cost analysis, Ernst & Young simply accepted that Hydro's classification of pole and wire was "within acceptable limits on an overall basis," not a difficult standard to meet given that Ernst & Young reported customer-classification factors that ranged from 0% to 70%.

Q: Do many jurisdictions and utilities currently classify poles and wires as 100% demand-related?

A: Yes. Jurisdictions that I understand allocate distribution lines 100% on demand include Utah (Rocky Mountain Power), Oregon (Portland General Electric), Colorado (Public Service of Colorado), Illinois (Commonwealth Edison, Ameren, and Mid-American),[34] Maryland (BGE, PEPCo, Delmarva,

[34] "As it has in the past,…the [Illinois Commerce] Commission rejects the minimum distribution or zero-intercept approach for purposes of allocating distribution costs between the customer and demand functions in this case. In our view, the coincident peak method is consistent with the fact that distribution systems are designed primarily to serve electric

and Potomac Edison), Texas (all regulated distribution companies), and Arkansas (Entergy Arkansas, Southwestern Electric Power).[35]

Q: How should the PCOSS classify the costs of distribution lines?

A: Other than the costs that varies primarily with the number of customers (e.g., service drops, meters) , distribution equipment should be classified entirely as demand-related, unless Manitoba Hydro can identify specific portions of the distribution system that vary with customer number rather than load (such as the small percentage of customers whose locations add a small increment to the line costs).

2. Inherent Errors in Minimum-System Analyses

Q: Would a minimum distribution-system analysis provide a reliable basis for classifying distribution investment?

A: No. Both of these methods for classifying distribution costs are seriously flawed, and overstate the portion of distribution that is customer-related.

Q: Is the minimum-system approach that considers mileage of system as customer-related and size of components as demand-related based on a realistic view of an electric distribution system?

A: No. This view is overly simplistic, for at least three reasons that relate to both poles and wires. First, much of the cost of a distribution system is required to cover an area, and is not really sensitive to either load or customer number.

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demand. The Commission believes that attempts to separate the costs of connecting customers to the electric distribution system from the costs of serving their demand remain problematic." Docket No. 07-0566, Final Order, September 10, 2008, at 208.

[35] California has a more complex method that uses only the connection costs for existing customers, and the incremental extension costs for new customers.

The distribution system is built to cover an area, because the total load expected to be served will justify the expansion. Serving many customers in one multi-family building is no more expensive than serving one commercial customer of the same size, other than metering. The distribution cost of serving a geographical area for a given load is roughly the same whether that load is from concentrated commercial or dispersed residential customers.

Bonbright (a widely respected authority on ratemaking) finds that there is "a very weak correlation between the area (or the mileage) of a distribution system and the number of customers served by the system." He concludes, therefore, that "the inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems…clearly indefensible. [Cost analysts are] under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground…."[36]

Second, while the minimum-system approach assumes that the minimum system would consist of the same number of units (e.g., number of poles, feet of conductors) as the actual system. In reality, load levels help determine the *number* of units, as well as their size. As load grows, utilities add distribution feeders in parallel with existing feeders (sometimes on the same poles), and upgrade feeders from single-phase to three-phase. Manitoba Hydro acknowledges that it has "added distribution lines and distribution transformers due to current or anticipated overloading on the existing system" (IR GAC/MH I-24). It has also added distribution lines and line transformers in geographical areas with existing lines "to serve increased

[36]Bonbright, James, Albert Danielsen, and David Kamerschen. 1988. "Principles of Public Utility Rates." Arlington, Va.: Public Utilities Reports. 491–492.

loads of existing customers" (IR GAC/MH I-25) and "to serve the added load of new customers." (IR GAC/MH I-26).

Third, load can determine the type of equipment installed, in addition to size and number. Electric distribution systems are often relocated from overhead to underground (which is more expensive) because the weight of lines required to meet load makes overhead service infeasible. Voltages may also be increased to carry more load, requiring early replacement of some equipment with more expensive equipment (e.g., new transformers, increased insulation, higher poles).

Q: Please describe the Minimum-System Method.

A: A minimum-system analysis attempts to calculate the cost (in constant dollars) of the utility's installed units (transformers, poles, conductor-feet, etc.), were each of them the minimum-sized unit of that type of equipment that would ever be used on the system. The analysis asks, How much would it have cost to install the same number of units (poles, conductor-feet, transformers), but with the size of the units installed limited to the current minimum unit normally installed? This cost will be customer-related, and the remaining cost will be demand-related.[37]

The ratio of the costs of the minimum system to the actual system (in the same year's dollars) produces a percentage of plant that is claimed to be customer-related.

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[37]Calculating this ratio is not straightforward. The customer-related portion (which is computed in constant dollars) must be compared to the actual installed cost of the entire account (in mixed dollars); translating actual mixed dollars into constant dollars can be difficult, especially under conditions of technical change and different inflation rates for large and small installations (small installations are often more related to labour costs than are large ones, for example).

Q: Please describe the Zero-Intercept Method.

A: The Zero-Intercept Method attempts to extrapolate from the cost of actual equipment (including actual minimum-sized equipment) to the cost of hypothetical equipment that carries zero load, as in 0-kVA transformers, or the smallest units legally allowed (as 25-foot poles), or the smallest units physically feasible (e.g., the thinnest conductors that will support their own weight in overhead spans). The idea is that this procedure identifies the amount of equipment required to connect existing customers, even if they had virtually no load.

Q: Is the first approach, the minimum-system method, successful in separating customer-related from demand-related investment?

A: No, for the following reasons:

- The "minimum system" would still meet a large portion of the average residential customer's demand requirements.
- Minimum-system analyses tend to use the current minimum unit, not the minimum size ever installed. The current minimum system is sized to carry expected demand. As demand has risen over time, so has the minimum size of equipment installed. In fact, utilities usually stop stocking some less-expensive small equipment because rising demand results in very rare use of the small equipment and the cost of maintaining stock is no longer warranted.
- Minimum-system analyses usually ignore the effect of loads on the *number* of units installed, or the *type* of equipment installed. Hence, a portion of the costs allocated to customer number is really driven by demand.

- Minimum systems analyses fundamentally assume that all area-spanning investment is caused by the number of customers. As discussed above, this is not true.

Q: How do customer number and demand affect the number of units of distribution equipment installed?

A: A piece of equipment (e.g., conductor, pole, service drop, or meter) should be considered customer-related only if the removal of one customer eliminates the unit. The number of meters and, for the most part, services (although not the size of services) are customer-related, while feet of conductor and number of poles is almost entirely demand-related.

Reducing the number of customers, without reducing the demand in an area, will only rarely affect the length of lines, or the number of poles or transformers.[38] For example, removing one customer will avoid overhead distribution equipment only under the following circumstances:

- If the customer would have been the farthest one from the transformer on a secondary line along a feeder, a span of secondary conductor;
- If the customer is the only one served off the last pole at the end of a primary feeder, a pole and a span of secondary or a span of primary and a transformer.
- If several poles are required solely for that customer, all those poles and associated conductors.

In many situations, additional conductors are added to increase capacity, rather than to reach an additional customer. Examples of those situations include installation of three-phase rather than single-phase distribution;

[38] This is true even for new construction. For existing built-out areas, no costs are likely to be avoided by reduction in customer number.

building an additional feeder along the route of an existing feeder (or even on the same poles); looping a second feeder to the end of an existing line, to pick up some load from the existing line; and building an additional feeder in parallel with an existing feeder, to pick up the load of some of its branches. All these strategies add line length, to increase capacity rather than to reach another customer.

Q: Can the zero-intercept method be relied on to determine the customer-related portion of plant?

A: No. The determination of the number of units required for a zero-demand system are far from simple. A system designed to connect customers but provide zero load would look very different from the existing system. A zero-capacity electric system would not use the overlapping primary and secondary systems and line transformers that the real system uses. A system with very low loads would use a single distribution voltage, which eliminates many conductor-feet, reduces the required height of many poles, and eliminates the need for line transformers.

The zero-intercept method is so abstract that it can be interpreted in many ways, and can produce a wide range of results. Any use of this method must be grounded in a firm understanding of the purpose and conceptual framework for defining a zero-intercept.

B. Allocation of Substations and Feeders

Q: How did Hydro allocate substation costs?

A: Hydro used the sum of estimated class non-coincident peaks (“NCPs”). Specifically, Hydro determined when in the 2011/12 power year the peak occurred for each rate class, considered separately, and added up the results.

Q: How did Manitoba Hydro allocate feeders?

A: Manitoba Hydro allocated the demand-related portion of primary feeders (as well as secondary lines and poles) on same class NCPs used to allocate substations.

Q: Is class NCP an appropriate allocator for substation costs?

A: No. This allocator would be appropriate if each substation overwhelmingly served a single class, and if the substation peaks occurred roughly at the time of the class peak. Neither of these conditions actually applies to Hydro's system, for the following reasons:[39]

- Most substations serve more than one rate class. Residential and various types of general service loads are intermingled geographically and are thus served from the same substations.
- The peak seasons for substations do not align with the season of class NCPs.
    - In 2008/2009, some 58 of Hydro's 357 substations, representing 25% of the peak substation loads, and about 30% of installed capacity, were most heavily stressed in the summer, due to a combination of higher summer loads and lower summer capacity.[40] Yet none of the distribution-level classes peaked in the summer.[41] Thus, at least 30% of Hydro's substation costs were driven by loads entirely ignored in class NCPs.
    - In the 2014/15 data that Manitoba Hydro provided in this proceeding (GAC/MH-I-13), 24% of substations, representing

[39] In this regard, primary lines are analogous to subtransmission lines.

[40] 2010–2012 GRA, RCM/TREE/MH I-7(p).

[41] 2010–2012 GRA, RCM/TREE/MH I-5 (e).

    30% of peak loads, peaked in the summer. Assuming that substation capacities are 12% higher in the winter, 38% of substations and 47% of substation load were more stressed in the summer than in the winter.

    - In the 2015/16 data in GAC/MH-I-13, the summer-peaking substations rose to 38% of substations and 37% of load, and summer-stressed equipment to 62% of substations and 69% of load.
    - The data in GAC/MH-I-13 show substations peaking in every month except October.
    - The 2011/12 NCPs used in PCOSS14 are all in the winter.[42] NCPs occurred in January for the residential, GSS (both demand and non-demand), GSM and GSL <30kV, with the higher-voltage GSL classes peaking in November and March.

- Peak substation loads within a season are scattered among many days, as shown in Figure 1 for the substations for which Manitoba Hydro provided data (the Winnipeg Central region and the Eastern and Northern region). Figure 1 shows the number of substations peaking on each summer day in 2015. Similar scatter occurred in the 2014 summer and in both winters.

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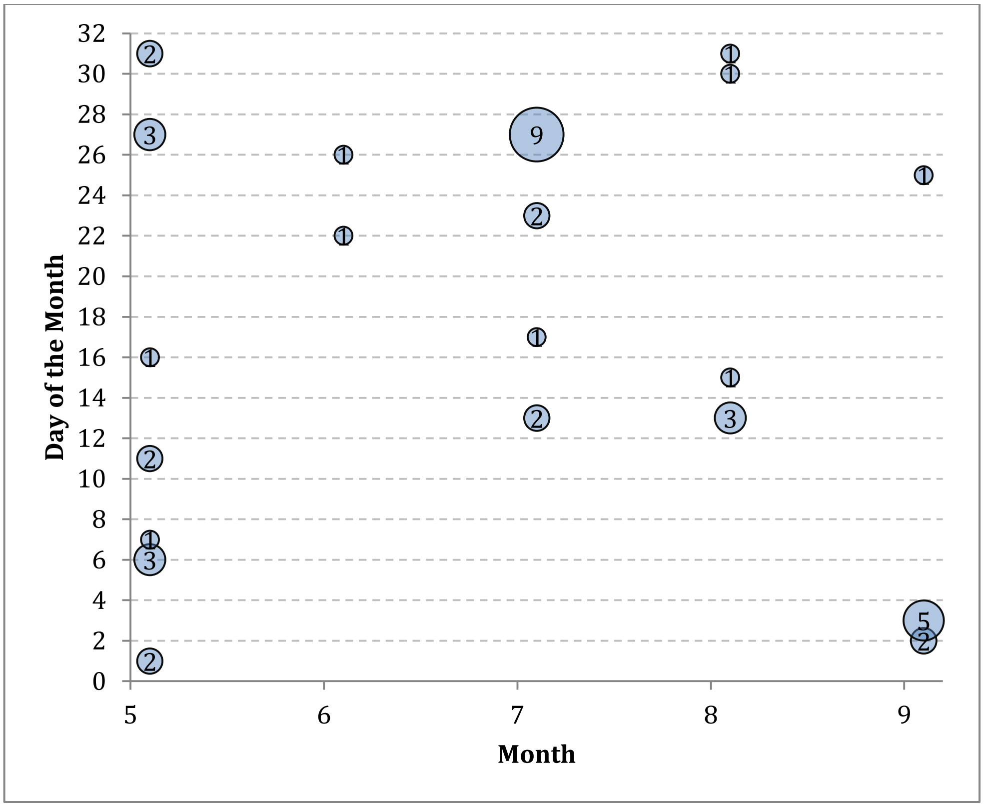
[42] These dates are provided in the "2012 Load Research at Generation Peak for PCOSS14" spreadsheet in a column labeled ""Non Coincident Peak Load, Nov-Apr." It is not clear whether there were higher class non-coincident loads in the summer, or why Manitoba Hydro would have limited the allocator for distribution and subtransmission to only the winter months.

Figure 1: Distribution of 2015 Summer Substation Peaks



- Of the winter substation peaks Manitoba Hydro provided for 2008/09, 2% of the capacity peaked at 9 am, 9% at 10 AM, 19% at 11 AM, 25% at noon, 21% at 5 PM, and 23% at 6 PM. The residential-class NCP was at 7 PM and the GS non-demand-metered NCP was at 2 PM. The other three classes peaked at 10 and 11 AM. Again, the majority of NCPs did not coincide with any substation peaks, and the majority of substation peaks did not coincide with any NCPs.[43]
- Similarly, the more recent data in GAC/MH-I-13 show substations peaking from 7 AM to 9 PM in the winter, and 10 AM to 10 PM in the summer.

[43]Similarly, most of the summer substation peaks occurred in the mid-afternoon, before most residential customers return home.

- All five of the distribution classes (residential, GSS non-demand, GSS small demand-metered, GSM, and GSL <30 kV) experienced their 2011/12 NCP on January 18 or 19, 2012.[44] But a substantial share of the distribution substations peaked in summer months in each year for which Manitoba Hydro has provided data.

Q: How should Hydro allocate substation costs?

A: Hydro should estimate the contribution of each class to the most constrained loading (i.e., the hours when load on the substation is the highest percentage of its seasonal rating) on each substation, or a representative sample of substations. The resulting allocator should reflect the variety of seasons and times at which substations peak.

Q: Does Hydro have all the information it needs to develop this allocator properly?

A: Apparently not, since it was able to provide the date of substation peak loads for only for the Winnipeg Central region and the Eastern and Northern region and the time of substation peak only for Winnipeg Central. As I discuss in Section VII, Manitoba Hydro needs to develop additional information on its system loads for planning, operational cost-allocation and rate-design purposes. Specifically, it needs to understand when each of its substations and feeders reaches its maximum loads, the mix of rate classes on each feeder and distribution substation, and how the timing of those loads relate to the customer mix on the system.

[44] In 2008/2009 two classes, representing 61% of the class NCPs, had NCPs in December, and the other three had January NCPs But every one of the 29 substations for which Hydro provided 2008/2009 winter peak data experienced that peak in January. Again, the (largely December) NCPs did not match the (entirely January) substation peaks.

Q: Is class NCP an appropriate allocator for primary feeders?

A: No. As in the case of substations, many feeders serve more than one class. In addition, there may be multiple feeders that serve primarily a single class but peak at different times, because the classes are not homogeneous.

Q: Do other jurisdictions allocate primary distribution on some measure of coincident peak?

A: Yes. For example, Rocky Mountain Power in Utah allocates primary distribution on monthly coincident distribution peak, weighted by the percentage of substations peaking in each month.

Q: How should the PCOSS allocate distribution substations and feeders?

A: Primary distribution should be allocated according to some measure of CP until better information about the mix of classes and the timing of distribution loads. Manitoba Hydro has not been able to provide any data on the timing, or even the seasonality, of feeder peaks. The best available measure of distribution loads in the short term may be the 2CP allocator used for transmission, with the summer weighted about 50%.

C. Subfunctionalization of Secondary Costs

Q: Has Manitoba Hydro presented any analysis to support its 30% adjustment to primary customers share of distribution costs?

A: No.

Q: Has MH provided any information on costs by voltage level?

A: The information MH has provided is limited to:

- The average cost of a pole for three sample pole types (GAC/MH I-32).
- A breakdown of underground cable costs between primary and secondary (GAC/MH I-17) and the total length of primary cable on the system by

type of cable (GAC/MH I-33). According to GAC/MH I-17, about 39% of cable costs are due to secondary.

Manitoba Hydro provides no information on the portion of overhead lines (by length or cost) that are secondary.

Q: Given the information available, can you say whether the 30% is a reasonable proxy for the portion of distribution that is secondary?

A: Manitoba Hydro estimates that 30% of distribution is due to the incremental cost of secondary service probably overstates that portion of costs, and hence the discount for the GSL<30kV class.

- Manitoba Hydro has provided data supporting treating 39% of underground costs as secondary.
- Secondary is more likely to be direct-buried, rather than installed in concrete ducts, so I assume that 20% of ducts are secondary.
- Secondary does not impose any incremental pole costs, as I explain below.
- Overhead conductors are likely to include much less secondary than underground, for the following reasons:
    - Underground distribution is generally installed in densely-settled area, with many connections to transformers and hence secondary, while some overhead primary can run for hundreds of meters between customers or secondary lines.
    - Underground distribution includes secondary networks, with large amounts of secondary cable connecting multiple customers to multiple transformers, while overhead is not networked in the same manner.

Table 6 computes the secondary portion of distribution costs, based on the assuming that about 20% of overhead conductors is for secondary.

Table 6: Secondary Portion of Distribution Costs

	Share of Distribution	% Secondary
U/G Cable & Devices	35%	39%
Concrete Duct line	6%	20%
Poles & Attachments	31%	0%
Conductor & Devices	29%	20%
Total Distribution		20%

Q: How are utility poles used in electric distribution?

A: There are four major groups of electric distribution pole uses. Many poles carry only primary lines, and many more poles (which I refer to as "joint" poles) carry both primary and secondary lines. In addition, in some cases a pole is needed to reach a particular secondary customer or two, so only secondary needs to be carried on the pole. Those situations typically occur when customers are far from the primary lines (e.g. across a wide road, or set far back from the road), or when a few customers at the end of a feeder can be served at secondary. In those cases, shorter, thinner and less-expensive secondary poles can be installed, rather than the taller, more-robust and more-expensive primary poles. Finally, some poles do not carry any conductor at all; these "stub" poles are used to support the conductor-bearing poles, by providing tension to offset the force exerted by the conductors.

Q: How can this information be used to develop a breakdown of pole costs between primary and secondary?

A: There are important methodological issues that must be settled before the pole data can be used in a COSS. Those methodological, or even philosophical, issues are as follows:

- Are secondary poles complementary to primary poles, imposing no additional costs beyond the costs of poles to serve customers at primary, or are the costs of the secondary poles incremental to primary poles?
- If the costs of secondary poles are incremental to primary poles, what portion of joint poles, which carry both primary and secondary lines, should be sub-functionalized as secondary?

a) The Role of Secondary-Only Poles

Q: What determines whether secondary poles are complementary or incremental to the primary poles?

A: The test is whether the pole investment would be greater or less for a particular location had a customer currently served with a secondary pole instead required primary service. Since a pole would be needed in that location regardless of voltage level of service, the question is whether the secondary pole is more or less expensive that a primary pole in the same place.

The answer is that a secondary pole serving a secondary customer would be less expensive than a primary pole required to serve the same customer at the same location at primary. Hence, the primary customers are better off paying for their share of the secondary poles than if the customers using those poles were to require primary service. It does not seem fair to penalize customers served at secondary for the fact that some of them are able to use a type of pole that is less expensive than primary poles.[45]

[45] In contrast, secondary customers should be charged for line transformers and secondary conductors, as additions to the primary system that they share with the primary customers.

Q: How should poles be functionalized, in light of the complementary nature of secondary poles?

A: In secondary poles are considered complementary to the primary poles, there is no need to sub-functionalize poles. All poles can be functionalized as distribution and allocated on total load at primary.[46]

If secondary poles are considered complementary to primary poles, it is not necessary to deal with the issues considered in the next section.

b) The Secondary-Related Cost of Joint Poles

Q: What determines the costs of the joint poles, which carry both primary and secondary lines?

A: The costs of poles that carry both primary and secondary lines are almost entirely necessary to serve the primary lines, for the following reasons.

- The number of joint poles could not be reduced if the secondary lines were eliminated.
- The height of each pole is determined by the voltage of the primary lines and the required clearance for the voltage from the ground and other structures. Joint poles are not taller than primary-only poles.
- The higher-voltage primary lines require equipment that is not required for lower-voltage secondary lines, including cross arms, hardware to hold the cross arms in place, insulators, anchors, connectors, and cutouts. In addition, there may be additional costs driven by the primary voltage and the resulting pole height, such as foundations and guy

[46] Alternatively, the COSS could credit secondary load for the pole savings allowed by secondary service, which would slightly reduce the cost allocation to secondary customers, but this approach seems unnecessarily complex.

wires.[47] This equipment can add a significant amount to the direct pole cost.

Q: What information has Manitoba Hydro provided on pole type and costs?

A: In response to GAC/MH I-32(e) and (f), Manitoba Hydro provided estimates of the percentage of poles of three types (primary only, secondary only and joint) and partial estimates of typical costs of each type of pole, as shown in Table 7.

Table 7: Manitoba Hydro Estimates of Typical Pole Costs

	Joint	Primary Only	Secondary Only
Average Cost of Pole	$1,700	$1,500	$1,250
% of Total Number of Poles	75%	13%	12%

These data suggest that a pole that could accommodate both primary and secondary lines would cost $200 more than a pole with only primary lines. This is curious, since the additional height of a primary pole is driven by the greater clearances necessary for its higher-voltage lines, and the higher class (measured by diameter) of both the primary pole is required by its greater height (and propensity to bend) and the additional cross-arms, insulators and other equipment required separate the primary feeders from one another. Hence, poles with only primary are often the same height and class (and hence cost) as those with both primary and secondary lines. Manitoba Hydro confirmed this reality in the workshop (Tr. 696)

The estimates are partial, as Manitoba Hydro explained in Undertaking #11:

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[47] The need for guys and supporting stub poles tends to be greatest when the line load on the pole is unbalanced, such as when the line changes direction to turn a corner or follow the curve of a road. The short secondary runs are much less likely to require those supports.

> The costs shown…are based only on the construction of a new tangent 45' pole structure as part of a green field installation supporting a single three phase overhead feeder and service without the use of any anchoring or supporting structures. Though this is a basic structure, there are a large number of variations. Poles can range from 30' to 70', can hold up to 8–12 overhead lines of varying voltage levels and may require multiple cross arms and insulators. Depending on the location of the pole, guying/anchoring may be required as might more advanced supporting structures such as rock anchors…

These additional costs would either be required only for primary lines (multiple cross arms and insulators for multiple feeders) or would tend to be more frequent and more expensive (anchoring, supporting structures) for the taller and more expensive primary poles.

Q: What useful information can be gleaned from this response?

A: If these estimates were realistic and reflected representative sample of pole types and costs, the average pole cost would be $1,620, and the portion in any way attributable to secondary would be $200 for the 75% of poles that are joint use and $1,250 for the 12% that carry only secondary lines, or an average of $300. Hence, no more than 18% of pole costs could be sub-functionalized as secondary. But since the secondary-only poles are complementary, rather than additive, to the cost of the primary system, and should not be allocated separately from the primary system. The incremental costs that Manitoba Hydro estimates for the joint poles over the primary-only poles would suggest that 9% of the pole costs are driven by secondary service.

Q: Are Manitoba Hydro's estimates of pole costs reasonable?

A: No. They are contradictory and implausible. I requested the assumptions underlying the estimates in Undertaking #11, in order to better understand the basis of Manitoba Hydro's pole-cost estimates. While Manitoba Hydro failed to provide any breakdown of the costs, the additional information provided indicates that the estimates overstate the costs of secondary distribution, for the following reasons:

- Manitoba Hydro assumed that it would install the same 45'-high class 3 pole for secondary alone as for a primary pole. This is not consistent with utility practice. While Manitoba Hydro has refused to provide its distribution construction guidelines,[48] a quick virtual tour of some Manitoba streets indicates that Manitoba Hydro follows industry practice and uses shorter poles for secondary. Secondary-only poles tend to be of lesser class (i.e., thinner) and hence less expensive than the primary poles, since they are shorter and carry less weight than the primary poles.
- The estimates exclude the more complex equipment required by some primary poles.
- As noted above, the estimates exclude anchoring and supporting structures, more likely to be needed for poles carrying primary lines.

- The pole cost estimates include overhead line construction labor (which sounds like it would involve installation of conductors), in addition to pole installation.

Q: Given those considerations, how should the costs of the joint poles be sub-functionalized, if the Board decides that poles need to be sub-functionalized?

A: It is not clear that secondary lines really add anything to the costs of the poles carrying both primary and secondary lines. Classes served at secondary pay for their allocated share of the joint pole, as a function of their allocators at

[48] GAC/MH I-41.

primary. Charging them twice for the same pole would be inequitable, as would be charging more for using secondary poles, when Manitoba Hydro saves money from using secondary poles instead of primary poles. Hence, the costs of poles should not be subfunctionalized, and all pole costs should be allocated on demand at primary.

D. Services

Q: How did Manitoba Hydro allocate service-drop investments?

A: The Company used weighted customer number, weighting residential and GSS single-phase customers at 1.0, and GSS three-phase, GSM and GSL<30 kV at 5.0.

Q: Why is a weighted service-drop allocator appropriate?

A: The cost of a service drop clearly varies with a number of factors that vary by class: customer load (which affects the capacity of the service), the distance from the distribution line to the customer, underground versus overhead service, the number of customers sharing a service (or the number of services required by a single customer),[49] and whether customers require 3-phase service. Unfortunately, Manitoba Hydro provides no analysis to support the service weights it used.

Q: Does Manitoba Hydro provides any analysis to support the weights used?

A: No (GAC/MH I-48, PUB/MH-58). Furthermore, the weights do not seem to reflect reality. For instance, the Company assumes that 3-phase service drops for all non-residential customer classes will have the same cost, whether for

[49] The number of services is smaller than the number of customers in the residential class (and to some extent small commercial), since several customers can share a service drop in multi-family housing and some commercial buildings.

the non-demand-metered GSS customers, all with a loads under 50 kVa, or the GSM and GSL distribution (<30kV) customers, all of whom have loads over 200 kVA.[50] Two of those GSM or GSL customers rank among Manitoba Hydro's 20 largest customers (GAC/MH I-46).

Q: Has Manitoba Hydro directly estimated the costs of typical service drops for each class?

A: No. Other utilities have performed analyses of this sort, selecting a representative sample of customers in each class, pricing out the customers' services, and extrapolating to the class as a whole.

Q: Have you estimated the impact of considering shared services on the residential allocation?

A: Yes. I have prepared a rough estimate, using the limited data I could find at short notice. I used two data sets, a 2011 census of housing stock and a more detailed 2015 census of the primary rental market, both reported by the Canada Mortgage and Housing Corporation (CMHC).[51] The 2011 census indicates that 29% of housing units in Manitoba are in multi-family buildings. Of those, 13% of customers live in low-rise apartment structures and 8% live in high-rises (defined as having five or more storeys).[52] I used the 2015 rental housing data to approximate the number of units in low-rise and high-rise buildings.

[50] PCOSS14 (Amended), Tab "C Tables," lines 306-339.

[51] The 2011 housing census covers all housing units, while the 2015 data cover only rental properties.

[52] I have not been able to reconcile these numbers with the data provided by Manitoba Hydro (GAC/MH I-51) on numbers of individually metered and bulk-metered units in multi-family buildings.

Depending on the number of units in each housing category, the total number of services installed for residential customers may be a quarter less than Manitoba Hydro assumes for allocation purposes, as shown in Table 8.

Table 8: Accounting for Shared Residential Services

Units in Structure	Assumed Units per Building	Housing Units	Services/ Customer	Number of services
Single-Detached	1	322,445	1.000	322,445
Semi-Detached	2	14,800	0.500	7,400
Row	2	13,955	0.500	6,978
Duplex	2	5,755	0.500	2,878
Low-Rise Apt: 3-5 Units	4	9,937	0.250	2,484
Low-Rise Apt: 6-19 Units	12	51,028	0.083	4,235
High-Rise Apt: 20-49 units	35	13,213	0.029	383
High-Rise Apt: 50-199 units	125	18,589	0.008	149
High-Rise Apt: 200+ units	200	6,153	0.005	31
Totals and Averages	1.3	455,875	0.761	346,982

Q: Is your use of census data to derive the number of shared services a reasonable basis for a services allocator?

A: Yes. The use of census housing data is clearly an improvement over Manitoba Hydro's assumption that every residential customer has its own service drop. However, Manitoba Hydro may be able to develop better data before its next filing of a PCOSS.

Q: How should the costs of services be allocated?

A: In the short term, the PCOSS should reflect that the residential class uses an average of less than one service per customer, using a computation similar to that in Table 8. In addition, Manitoba Hydro should re-estimate the relative cost of services, reflecting the lengths and sizes of services by class.

VII. Lessons Learned

Q: What lessons should the Board take from this exercise, in addition to your recommendations regarding functionalization, classification, and allocation of specific costs?

A: I have identified nine major lessons that can be learned from this proceeding, beyond the specific allocation issues. First, transparency is important in reviewing any cost-of-service study. While Manitoba Hydro's provision of its PCOSS as a spreadsheet with some formulas enabled was a step in the right direction, Manitoba Hydro provided only fixed values for some steps in the process, so that changing an input did not reliably affect the output. Board consultants needed to rework the model to allow for modification of Manitoba Hydro's assumptions and input. Future iterations of the PCOSS should start with the accounting costs and other inputs, which should then flow through the model in a traceable manner.

Second, Manitoba Hydro needs to clean up its data and document systems, so it can track costs, loads, and cost responsibility, for planning, operations, cost allocation, and rate design, including rates for distributed generation. For example, Manitoba Hydro should track the loads on its transmission and distribution system (including substations and feeders). As described in Section VI.B, Manitoba Hydro was not able to provide a consistent data set for its substations in the various regions in response to GAC/MH-I-13. Each of the four regions provided different data in a different format:

- The Winnipeg Central region had data for the time and date of summer and winter substation peaks for 2014/15 and 2015/16.

- The Eastern and Northern region had the date of just a single peak for each transformer bank (a portion of the substation) in 2014/15, but not the time of the peak.
- The Winnipeg Suburban area had data on the peak load level for summer and winter for both 2014/15 and 2015/16, but not the time or date (or even the month of the peak).
- For the Western area, Manitoba Hydro could provide only the season in which each substation peaked.

Manitoba Hydro was not able to provide any data on the loads on any feeders.

Third, Manitoba Hydro needs to manage its document flow, so that it can find important information efficiently. For example, Manitoba Hydro could not provide the documents that explain the need and justification for its distribution projects. (GAC/MH I-28 and Tr. 684–692) Without those documents, it is impossible to review the likely requirement for distribution investments (in a GRA), or the driving factors behind its investments, which is important for both such questions as whether customer number drives distribution expansion (in the PCOSS) and the marginal cost of distribution (for rate design and DSM screening). Manitoba Hydro clearly develops these documents, since they would be required in the development and approval of the annual Capital Expenditure Forecast; Manitoba Hydro should retain those documents in useable form, so that they can inform cost allocation, rate design, resource planning, DSM screening, and other activities.

Fourth, the Board needs to develop a standard non-disclosure agreement for sensitive data relevant to regulatory proceedings. Manitoba Hydro refused to provide documents that are routinely provided by other utilities in regulatory proceedings, such as its construction standards, on the grounds of confidentiality, and because there was insufficient time to develop a non-disclosure agreement.[53] Whatever the merits of Manitoba Hydro's position on access to export contract terms and pricing, a number of less-sensitive documents should be available to intervenors without onerous conditions.

Fifth, the Board should instruct Manitoba Hydro to develop actual data-based estimates of PCOSS inputs for which Manitoba Hydro currently has no factual support, such as the subfunctionalization of distribution lines between secondary and primary drivers, and the weights for service drops.

Sixth, Manitoba Hydro should review the derivation of the weighting of energy use among the daily and seasonal periods, particularly with regard to the differences between SEP and MISO pricing, and selection of a representative period for historical data, considering changes in fuel prices and changes in the MISO generation mix.

Seventh, Manitoba Hydro need to develop a method for assessing the equity of the allocation of DSM costs, as I describe in Section III.A.

Eighth, the Board should not wait decades after this proceeding to re-examine cost allocation issues. Whether through additional phases of this proceeding, biennial cost-of-service cases, or the GRAs, the Board should continue the process until the many outstanding data issues are resolved. As Manitoba Hydro's major pending projects (Keeyask, Bipole III and US ties) near or reach completion, the Board should revisit decisions about allocation

[53] Manitoba Hydro previously took the same position towards its PCOSS and all other spreadsheets in rate proceedings. In this proceeding, Manitoba Hydro finally provided at least a crippled version of its PCOSS, which Daymark has improved considerably. Similar barriers to the sharing of information may arise in the next GRA and beyond. For example, once it organizes its project-justification documents, Manitoba Hydro may be reluctant to provide them without a confidentiality agreement.

of generation, interties, and DSM costs; allocation of costs to exports, and and the treatment of export revenues.

Ninth, the Board would be well-served by structuring future proceedings with multiple rounds of discovery. Manitoba Hydro has not done a good job of providing information or explanations in the single round of discovery. The attempt to use the workshop format for follow-up on discovery proved ungainly, since the parties had limited time and divergent expectations regarding the purpose of the workshops. Combining the detailed examination of Manitoba Hydro responses (e.g., working through apparent inconsistencies in the numbers, determining what data Manitoba Hydro might be able to provide) was not a productive use of the time of all the experts, attorneys and Board Members in attendance, many of whom probably expected a conceptual discussion of cost allocation approaches. Splitting the formal and informal discovery from the conceptual discussions would probably benefit both processes.

Q: Does this conclude your evidence?

A: Yes.