PRE-FILED TESTIMONY OF
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IN REGARD TO MANITOBA HYDRO
2016 COST OF SERVICE APPLICATION

Submitted to:

The Manitoba Public Utilities Board

on behalf of

Manitoba Industrial Power Users Group

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1.0 INTRODUCTION

This testimony has been prepared for the Manitoba Industrial Power Users Group (MIPUG) by InterGroup Consultants Ltd. (InterGroup) under the direction of Mr. Patrick Bowman. MIPUG's current membership and concerns are outlined in Section 1.2. The qualifications of Mr. P. Bowman are provided in Attachment C.

InterGroup has been asked to identify and evaluate issues arising from Manitoba Hydro's (Hydro or MH) filed material regarding its Cost of Service Study (COSS) Review that are of interest to industrial customers. In particular, the scope of the review includes matters relating to the proposed COSS methods, taking into account normal regulatory review procedures and principles appropriate for Canadian Crown-owned electric power utilities.

Hydro's COSS Review is based originally on the Prospective Cost of Service Study for the Year Ending 2013/14 (PCOSS14) and the amended PCOSS14 (PCOSS14-Amended) specifically updated for this proceeding.

This pre-filed testimony is presented in the following sections:

- Section 2 provides background on Cost of Service (COS) for utilities in the context of rate regulation and outlines tests of causation and other considerations for cost assignment within a Cost of Service study.
- Section 3 covers allocated costs in Hydro's COSS, including functionalization, classification and allocation topics including Export class participation.
- Section 4 looks at proposed direct assignment of costs for domestic customers. This includes Hydro's method change to directly assign DSM costs to each customer class.
- Section 5 deals with policy related items included in the Cost of Service Study including the Uniform Rate Adjustment, Affordable Energy Fund and Net Export Revenue.
- Attachment A provides COSS analysis on Hydro's current study compared to past Hydro COSS studies and methods.
- Attachment B provides background on the export class in Hydro's COSS.

1.1 SUMMARY OF TESTIMONY

For the most part, Hydro's Cost of Service methods reflect standard practice for regulated utilities in North America. However, in a number of areas Hydro's methods are at the extreme end of normal

practice, outside of the range of practice, or are contrary to previous and repeated PUB rulings on cost allocation.

Focusing on Cost of Service principles, the following recommendations are addressed in this submission:

1) **Cost Causation Principle:** The key principle guiding Hydro's cost of service allocation should be cost causation, considering the fundamental economic identity of each asset or cost item. It is not enough to determine that a given asset is used in a particular manner in the test year scenario, if the driver for the asset (or the driver for the choice of this asset over another asset) shows a different economic logic than the specific use in the test year. (Section 2.3)

For Costs that are Allocated among Multiple Classes:

2) **Generation Resources:** Manitoba Hydro's generation resources provide two concurrent services, energy and peak demand. The appropriate classification of generation resources therefore should reflect a contribution or investment in regard to each service (with the exception of wind, which should be classified 100% to energy). Manitoba Hydro's current approach under-classifies costs to demand. An appropriate classification of generation costs to demand should be established in the range of 21-23% at this time, with Hydro to further review method options for refining this classification between energy and demand.

    a. Consistent with the winter peak capacity constraint in Hydro's resource planning, generation costs classified as demand should be allocated on the basis of the winter 1CP, as per PCOSS14-Amended, Schedule D1.

    b. For the remaining costs classified as energy, Hydro's weighted energy allocation approach from PCOSS14 (i.e., without the extra Curtailable Rates Program adder used in PCOSS14-Amended) is appropriate, as this approach recognizes that kW.h consumed at different times are not equally important to driving system costs. (Section 3.1)

3) **Generation-Related Transmission:** In PCOSS14-Amended Hydro functionalizes a very significant amount of transmission assets to the generation function (commonly known as Generation Related Transmission Assets (GRTAs)). This GRTA approach is used at times in other jurisdictions, but should only be applied in a limited number of circumstances where the transmission and generation are integrally linked, and each would not exist in any form "but for" the other:

    a. Generator Outlet Transmission and Bipole I and II largely pass the test for treatment as a GRTA and should be functionalized to generation. This should likely include Wuskwatim outlet lines W1, W2 and W3 which are presently not treated as GRTAs.

b. The Dorsey converter station does not meet the threshold to be functionalized as a GRTA and should be functionalized as transmission, and classified and allocated consistent with the other components of the transmission system.

c. Bipole III fails to meet any reasonable test to be functionalized to generation as a GRTA. Bipole III does not have an economic identity linked to new generation (hence it preceded the decision to proceed with Keeyask and was excluded from the Needs For and Alternatives To (NFAT) review) nor to the older Nelson River generation (which was in service for decades without Bipole III). The economic identify of Bipole III is driven by high winter energy use. As such Bipole III should be functionalized as transmission, and either classified to demand and allocated using a 1 CP Allocator, or alternatively classified to winter energy and allocated based on weighted winter peak and shoulder period energy. The same conclusion can be made for Riel converter station, given the impetus for the converter is entirely aligned with the Bipole III project and that the converter is not cited to provide other systemwide benefits. (Section 3.2)

4) **US Interconnections:** Hydro's proposal to classify US interconnections to energy should be rejected. There is no compelling argument to treat these lines different than any other AC transmission (including interprovincial interconnections, which Hydro proposes to retain as classified to demand). (Section 3.2.2)

5) **Export Class Allocation:** Based on the large quantity and integral nature of exports (both dependable and opportunity) to Hydro's system, and the economic identity of generation additions being based on gaining contributing revenues from both dependable and opportunity export sales, generation and transmission costs should be allocated on the basis that all export sales share in the fixed costs. The exception is the Brandon coal plant which cannot be used in any way to support exports and should be allocated entirely to domestic classes. (Section 3.3)

6) **Customer Service Costs:** For Customer Service General Costs allocated through the C10 allocator, the information provided to date on the cost subcategory 'Customer Service' (Other) does not substantiate $1.2 million in allocated costs to industrial classes for the services listed. On a normal basis, few if any of these services would relate to services to industrials, which already are allocated substantial amounts for staff involved in the customer service functions requiring direct communication and consultation with these customers. Absent further compelling information from Hydro, there would appear to be no basis to allocate these costs to industrial customers. (Section 3.4)

For Costs that are Directly Assigned to a Given Class:

7) **Demand Side Management Costs - Energy Programs:** Hydro's proposed approach to directly assign the costs of DSM programs that are undertaken for energy efficiency reasons to the participating rate classes should be accepted. (Section 4.1)

8) **Curtailable Rate Program:** Hydro's proposed approach to the Curtailable Rate Program cost assignment and allocation is largely appropriate. However, in Hydro's current PCOSS14-Amended, the customers participating the Curtailable program are burdened with net costs related to this program. This does not appear to be the intent. This would be contrary to the very idea that participation in the program is to benefit the other classes (who do not get interrupted at peak times), and would serve to claw back from Curtailable customers a significant share of the credits they receive on their bills through higher firm power rates. This arises from a mathematical mismatch in PCOSS14-Amended, due to being charged a given amount for the program costs, but credited a lesser amount to reflect the program allocation step. This should be corrected by way of an upward adjustment to the values used for the allocation step in the PCOSS14-Amended. (Section 4.2)

9) **Policy Related Adjustment:** Within Hydro's COSS, there are two policy-related adjustments that directly assign items to the export class driven by policy. These items are not related to the costs of supplying exports, but instead reflect Hydro's interpretation of the desired rate setting policy framework. Further these items do not in fact relate to the cost of providing service in the test year:

   a. The Uniform Rate Adjustment was a result of a one-time rate impact of potential revenue burden to some residential, General Service Small (GSS), General Service Medium (GSM) and lighting customers in 2001. It is not a cost but a revenue reduction and Hydro's approach of applying it as a cost and retaining it some 15 years later distorts COS results. As a result this adjustment should not be included in the Cost of Service Study methods. (Section 5.1)

   b. With respect to the Affordable Energy Fund (AEF), this fund was to be established from an allocation of 2006/07 export revenues to fund activities over a number of years. The full allocation from 2006/07 has still not yet been spent. There is no reason this program should show up as a PCOSS14-Amended cost of providing service in 2014 when it was to be fully funded outside of the ongoing revenue requirement. Regardless as to Hydro's accounting treatment of the AEF program, it should not be included as a cost of providing service in the PCOSS. (Section 5.2)

10) **Net Export Revenue:** The Net Export Revenue (NER) category represents revenues that are is not inherently linked to costs, but instead are a form of residual after the export class is allocated its fair share of system costs based on the export load profile and capital planning assumptions. As such there is a reasonable basis to not allocate the NER via the Cost of Service study. Alternative treatment of the NER that credits this amount to the benefit of ratepayers can be developed, including options to hold it in reserve under the direction of the PUB, in order to help provide more stable rates in future when one-time event such as droughts occur, to the long-term benefit of ratepayers. Before such an approach is adopted, it is critical that the exports not be under-assigned cost responsibility in the PCOSS. (Section 5.3)

Table 1: Summary of Recommended COS Methodology re: Bulk Power

Resource		**Function**	**Classification**	**Allocation**	**Participating Classes**
Generation	All generation resources not otherwise noted	Generation	Demand & Energy (e.g., 23:77)	Demand – winter CP Energy – Marginal Cost Weighted Energy	Domestic plus all Exports
	Wind	Generation	100% Energy	Energy – Marginal Cost Weighted Energy	Domestic plus all Exports
	Brandon Coal	Generation	Demand & Energy (e.g., 23:77)	Demand – winter CP Energy – Marginal Cost Weighted Energy (or Unweighted Energy)	Only Domestic
Transmission	All other transmission resources not otherwise noted	Transmission	Demand	2 CP	Domestic plus all Exports
	US Connections	Transmission	Demand	2 CP	Domestic plus all Exports
	Bipole I&II, Henday/Radisson and Collector/Outlet lines	Generation	As per hydraulic generation	As per hydraulic generation	As per hydraulic generation
	Bipole III	Transmission	Demand	Winter CP or 2CP	Domestic plus all Exports
			Alternatively – Winter Energy	Marginal Cost Weighted Energy over the Winter Peak and Shoulder Periods	Domestic plus all Exports
	Dorsey HVDC components	Transmission	Demand	2 CP	Domestic plus all Exports
	Riel HVDC components	Transmission	As per Bipole III	As per Bipole III	As per Bipole III
DSM	Energy Savings Programs	Directly Assigned to the Participating Class			
	Affordable Energy Fund	Not included in PCOSS			
	Curtailable Service	Generation	As per hydraulic	As per hydraulic	As per hydraulic

1.2 BACKGROUND ON MIPUG MEMBERS AND THE GSL CLASS IN RELATION TO COST OF SERVICE

MIPUG is an association of major industrial companies operating in Manitoba. The purpose of the association is to work together on issues of common concern related to electricity supply and rates in Manitoba. To that end, MIPUG intervened in each of the Board's reviews of Hydro rates since 1988, as well as the Board's review of the Centra Gas Acquisition in 1999, Hydro's Major Capital Project review in 1990, the 2006 Cost of Service Review and most recently in the Hydro's Needs For and Alternatives To (NFAT) review in 2014.

MIPUG membership currently includes of the following companies:

- Amsted Rail - Griffin Wheel Company, Winnipeg;
- Canexus Chemicals, Brandon;
- Enbridge Pipelines Inc., Southern Manitoba;
- ERCO Worldwide, Virden;
- Gerdau Long Steel North America – Manitoba Mill, Selkirk;
- Koch Fertilizer Canada ULC, Brandon;
- Tolko Industries Ltd., The Pas; and
- TransCanada Keystone Pipeline, Southern Manitoba.

MIPUG member companies represent approximately half of the General Service Large (GSL) >30kV load, in two specific customer groups: GSL 30-100kV and GSL >100kV (both curtailable and non-curtailable customers). MIPUG customer issues are not individual to these specific customers but are representative of industrial and business power users that use electricity for production operations.

In previous interventions, MIPUG members, as major power users, have consistently expressed concern about the long-term interests of Hydro's domestic customers with respect to the following items:

- The need for stability and predictability of domestic rates over the long as well as short-term;
- The need for strong regulatory oversight and approval of all rates charged by Manitoba Hydro;
- The need to ensure Hydro's long-term system planning promotes rate stability and predictability over the long-term;
- Protection for domestic customers against higher rates or risks caused by Hydro's investments in subsidiaries, new export ventures or major new capital programs that do not promote least-cost long-term rates for the utility's domestic electricity customers;

- Protection for domestic customers against changes in government charges for items such as water rentals, debt guarantees or any other policy-related factors that increase the general rates charged to domestic customers;
- Assurance that general customer rates are reasonable within the context of long-term cost projections and provision of secured financial reserves that are appropriate in light of Hydro's past practice and the specifics of the Manitoba market; and
- Assurance that rates to each customers class reflect Cost of Service calculated in accordance with principles appropriate to Canadian regulatory practice for Crown electric utilities.

MIPUG has indicated that the basis for their intervention is that electricity prices matter greatly to industrial customers. MIPUG members have indicated that they are concerned about persistent electricity rate increases undermining the advantage of operating in Manitoba. Cost-based, stable and predictable electricity prices are cited as being critical to the success of Manitoba industry and provide a competitive advantage and help to offset some of the challenges of operating in Manitoba, including climate and distance to market. MIPUG companies have made long-term investments in Manitoba, based on expectations of stable, cost-based rates, clear and transparent regulation, and reliable service.

Cost of Service reviews provide the predominant opportunity to ensure that the rates charged to GSL 30-100kV and GSL >100kV customers are based on costs incurred to serve those specific rate classes, and based on principles appropriate to Manitoba Hydro.

2.0 COST OF SERVICE APPROACH

The current Cost of Service review is the first to occur in a decade, and incorporates methods linked to existing and planned changes to Hydro's asset complement, market participation, and domestic loads. As a natural consequence Hydro is proposing some methodology changes to its Cost of Service Study.

It is important within a review of any utility's cost allocation methods to consider items of relevance to help determine appropriate methods and cost considerations. This can include but is not limited to general engineering and economic characteristics, framework for regulating the utility in terms of past practice, overall policy, the history by which the present system has evolved, and future planning and considerations as appropriate.

This section reviews at an overview level the following considerations relevant to the review of Cost of Service:

- Background and Context
- Role of Cost of Service in Electricity Pricing
- Tests of Causation For Cost Assignment
- Other Considerations for Cost of Service Practice

2.1 BACKGROUND AND CONTEXT

As a general principle, prices for electricity throughout North America are set based on one of the following three basic approaches – 1) based on generation markets such as in Alberta or Ontario (with government subsidies or rebates at times being provided to certain groups); 2) by government, based primarily on political considerations, such as in Saskatchewan, currently in British Columbia, and in Manitoba prior to the Crown Corporations Public Review and Accountability Act of the late 1980s[1]; or 3) based on regulated Cost of Service approaches, such as in British Columbia during periods where the Utilities Commission has ratemaking authority, Yukon, Northwest Territories, Newfoundland, and in Nova Scotia.[2]

In Manitoba, under the current legislation, the system in place is regulated ratemaking based on costs - there is no provision for market pricing to firm domestic customers or for government directed ratemaking (outside of clear direction in legislation or regulations, such as in the case of Uniform Rates legislation).

[1] This approach is also similar to that used by other non-electric utilities such as many Canadian water and sewer services.

[2] In some cases, only a portion of the respective utility's rates or tolls are regulated based on cost-of-service principles.

In the context of the current proceeding, it is also important to acknowledge the fundamental tenets underlying electricity pricing and policy existing in Manitoba since at least the 1970's.[3] Manitoba electricity prices are based on the costs required to operate the public power electricity system put in place in past years. These prices reflect the underlying "heritage resources" developed and paid for by Manitoba electricity consumers[4] who took on the costs and risks related to major generation and transmission developments (both one-time investment risks, as well as ongoing risks related to water flows, plant performance, etc.). In this regard, the generation and transmission resources currently in place (the "bulk power" system) represent the entitlements of ratepayers to attractive and stable electricity prices. Interconnection to other jurisdictions have been integral to this policy approach, in that the ability to trade in power enables development (and in some cases allows advancement of development) of large northern hydro stations, in excess of what would be required or economic for solely domestic requirements at any given point in time.[5] Absent these connected markets, Hydro's system would look considerably different in terms of both when investments are made in generation, and what resources are actually built. This export context allows rates to be lower than they would otherwise be (were the major hydro developments not otherwise possible) and more stable (since fluctuations and risks related to such factors as Manitoba load levels can be offset in part by complementary changes to quantity of power exported, and since the ongoing costs of hydraulic generation are not subject to fuel price fluctuations).

In the case of similar hydro-based electric power jurisdictions, such as Quebec and BC, the scale and scope of heritage resources has been defined and confirmed by government policy as a stable and protected assurance of a secured quantity of low cost generation[6] (stable in that the quantity and pricing mechanism are fixed and not subject to risks of drought, etc.). In Manitoba, the objective of attractive and cost-based rates is achieved via setting a cost-based revenue requirement (net of export revenues) for the utility in total, as well as for each customer class. Manitoba, however, does not have the same

[3] This basic set of principles is set out in numerous documents from the 1970's through the present, including reports of Manitoba Hydro, the provincial government, the PUB, as well as previous agencies such as the Manitoba Energy Authority.

[4] In the case of the HVDC system, there was financing from the Government of Canada, provided for the benefit of Manitoba electricity consumers.

[5] This basic relationship is set out in detail in the PUB's Report to the Minister regarding Manitoba Hydro's 1990 Capital Plan, section 3 and page 5-4.

[6] In Quebec this is represented by an assured supply to domestic customers of 165 TW.h at a price of 2.79 cents/kW.h (increasing annually with inflation) from the heritage pool of electricity as set out in section 52.2 of An Act Respecting the Regie de l'énergie. In BC this is represented by a "Heritage Energy" amount of 49,000 GW.h which is to be provided to BC Hydro Distribution based on the embedded costs of the Heritage Resources as described at page 16 of the BCUC Report and Recommendations in the Matter of British Columbia Hydro and Power Authority and An Inquiry into a Heritage Contract for British Columbia Hydro and Power Authority's Existing Generation Resources and Regarding Stepped Rates and Transmission Access (October 17, 2003).

degree of well-developed means to assure the stability of rates in the face of the risks of drought as exist, for example, in Quebec.[7]

Similarly, these same basic tenets have been confirmed in the current Manitoba plans to develop or enable new renewable supply resources, such as new hydro and wind. These developments only occur, and more specifically can only be justified in their current form, based on the ability to make a wide variety of sales to export markets. In each case, the premise put forward by Hydro (such as at the recent NFAT hearings) is that these generation and transmission investments are ultimately aimed at maintaining stable and low cost electricity for Manitobans, along with all the associated advantages for cost-of-living, jobs and investments, and development of renewable public resources (and in the current hydro developments, opportunities for northern community investment).

The most relevant component of the NFAT evidence for the purposes of the COSS was the assessment of "Plan 5" (effectively the plan ultimately approved, with Keeyask and a 750 MW transmission line). The preference for this plan (e.g., as compared to "Plan 1" the lower capital cost plan based only on natural gas) hinged entirely on export revenues from all sources (dependable and opportunity). Absent a large export contribution to offset the higher costs of the developments compared to a basic Natural Gas plan, there is no business case for Keeyask.

Contrary to possible misconceptions, the existing Manitoba framework for power pricing does not require prices for power within the province to be set at a level that encourages inefficient use. As reviewed later in this evidence, rate designs in place, and in development, help ensure all existing customers face consumption decisions that discourage wasteful use and encourage conservation. Sending efficient price signals via rate design can be done in a way consistent with the fundamental Manitoba tenets set out above, but at the same time do not penalize or create barriers against growth (be it new residences, new industries, or expansions of existing industries). Under market approaches, or quasi-market approaches such as full marginal Cost of Service, the latter effect arises.

Nothing has been provided by Hydro or the government to indicate a change to this fundamental policy of power at cost, based on historic investment with export revenue offsets, to sustain attractive and stable cost-based rates.

[7] Manitoba's sole approach to maintaining some stability in regards to drought risk is to earn significant net income in high flow years, which is accounted for as "shareholder's equity" so that significant net losses in drought years can be borne. This is in significant contrast to a number of other utilities who often maintain various regulatory "stabilization" accounts under the direction of the respective regulator, with specific detailed rules regarding use of the funds (in some cases accounted for analogous to a trust account by the utility). Or in the case of Quebec, a directive from government ensures that the bulk power costs for ratepayers of the overwhelming majority of the output of the Hydro Quebec hydraulic and thermal generation system is at a fixed quantity and fixed price every year, regardless as to export market conditions, fuel prices, or water flows.

2.2 ROLE OF COST OF SERVICE IN ELECTRICITY PRICING

In order to fulfill normal ratemaking principles, the relative levels of rates charged to various customer classes by Manitoba Hydro are to be developed based on principles of Cost of Service, or determining a fair allocation of Hydro's costs to the various classes based on a consistent set of principles. This retains the concept of used and useful – for example, if a customer class does not use a component of the system (e.g., distribution), its rates are not to include the costs of that component of the system; likewise if only one class uses assets (such as streetlights) all costs related to those assets are to be allocated to the relevant class.

The purpose of a Cost of Service study is well described in the National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual (January, 1992), as follows:

> Cost of service studies are among the basic tools of ratemaking. While opinions vary on the appropriate methodologies to be used to perform cost studies, few analysts seriously question the standard that service should be provided at cost. Non-cost concepts and principles often modify the cost of service standard, but it remains the primary consideration for the reasonableness of rates.[8]

The NARUC manual goes on to describe that after a revenue requirement is set, there remains two separate but distinct steps: First, the cost allocation, and second the design of rates.

Hydro's interpretation of its Cost of Service study stands in stark contrast to this regulatory standard. In particular in its letter of February 5, 2016, Hydro notes that its COS study is "…similar to Manitoba Hydro documents reviewed in the course of a GRA like the Integrated Financial Forecast [IFF] - it informs the PUB but does not direct rate approvals". MIPUG strongly disagrees. The IFF is a document that is used for multiple business purposes within and outside of rates, with multiple audiences outside of the PUB. Any reasonable business has a document akin to the IFF. In contrast, the COS study is a tool oriented solely at rates and matters within the PUB jurisdiction. It is within an area of professional practice that is unique to regulated utilities. The COS study is the gold standard for determining the fairness of rates, and as such the study can and must be based on methodologies and approaches, in which the PUB and parties appearing before it have confidence.

The Cost of Service Study is required in order to ensure that different rates which collectively result in generating sufficient revenue for Hydro are individually just and reasonable to each class of ratepayer. Based on the results of the study, once finalized, a rate design can be developed to recover the

[8] National Association of Regulatory Utility Commissioners (NARUC), (January, 1992), Electric Utility Cost Allocation Manual, Chapter 2: Overview of Cost of Service Studies and Cost Allocation, page 12

appropriate level of costs from the respective customer classes, as well as achieve key objectives such as stability, efficiency, etc.

2.3 TESTS OF CAUSATION FOR COST ASSIGNMENT

The preparation of a Cost of Service study requires two major assessment to be done on each cost that are intended to go to the heart of the concept of "cost causation":

- First, *what is the nature of the cost incurred*, i.e., the fundamental economic identity. Why was the cost incurred? What types of system load result in the cost to increase from year-to-year? Established practice is that costs which serve multiple users are put through a process of allocation, incorporating the well-known steps of functionalization, classification and allocation (dealt with in Section 4 of this testimony). Costs which serve only one user or load type are Directly Assigned to that user (dealt with in Section 5 of this testimony).
- For those costs that are allocated, the second step is determining *which classes should be allocated a share of the costs* (i.e., the "participating classes"). This requires consideration of many of the same questions noted above, as well as potentially a greater focus on the asset use: Which classes use the asset? Also whether specific class revenues and uses were presumed in the decision to incur the cost?

The general concept of cost causation tests can often be framed as assessing both why an asset was built, and how it is used, or alternatively assessing how the system is 'planned and operated'. These concepts only note that the impetus for an asset, and the use of the asset, are both relevant to determining cost causation. However, this language provides no guide on which item to focus on, or how to balance the two concepts (particularly where they compete). This is the basis for referencing the economic identity of the cost item. For example, each of the following cost of service examples reflect cost causation linked to the asset's economic identity, but to achieve this result they must balance planning versus use in entirely different ways:

- **Focus on "planned for", not "used for":** In Yukon, the major hydro plant had three units which would utilize effectively the entire river flow in winter. In the 1980s, a fourth unit was added in parallel to the original three, due to there being substantial summer surplus flows that could not be utilized by the then existing three units. As this is a winter peaking system, and the fourth unit contributed effectively no added system capacity in hours that mattered, the unit was

classified 100% to energy, which was accepted by the regulator.[9] On a use basis, however, the utility operators are free to dispatch the fourth unit ahead of the first three, even during peak winter hours. This operational approach is reasonable, and reflects many overlapping considerations that go into the hour-to-hour management of the utility assets. However, it does nothing to change the economic identity of the investment – to capture more annual energy without adding effectively anything to the system peak hour capability. The unit remains classified 100% to energy despite the fact that it is frequently used at winter peak times.[10]

- **Focus on "used for" not "planned for":** In Manitoba, the Kelsey generating station was developed on the Nelson River during the late 1950s "with the sole purpose to provide power to Vale (formerly International Nickel Company or INCO) mining and smelting operations in the Moak Lake and Mystery Lake areas and to the City of Thompson".[11] Although this planning priority focused solely on providing power to Vale, the station no longer retains this economic identity since it is now used as an integrated part of the entire LWR/CRD and Lower Nelson River generation and transmission complex. If these facts had not changed, and the additional Nelson River generation and transmission not been developed, the appropriate Cost of Service treatment of Kelsey may likely have been as an asset directly assigned to Vale.

- **Focus on neither "used for" nor "planned for":** A good example is the Brandon coal plant[12], which in the median water flow year modelled in PCOSS14-Amended produces almost no power. In this regard, there is almost no party who uses the kW.h's. Further, the Brandon plant no longer retains a linkage to the original purpose or role from the 1950s, prior to any interconnections and pre-LWR/CRD. The proper allocation of the Brandon plant has to look at the economic identity relevant to today – why does the asset continue to remain in service? In the case of Brandon, the asset remains in service because it provides useful capacity and energy for the purposes of supplying domestic load (and not export load) in the cases of extreme drought. Regardless as to its "use" in a given year, the plant is useful, and its economic identity is as a common asset (i.e., should be allocated broadly and not directly assigned to one class), as generation, serving both a peak demand and an energy function (with energy receiving a higher

[9] The companies state that the rationale for building unit #4 was to replace diesel generation with the lower cost hydro generation and no extra peaking capacity was provided to the system. This originated from Recommendation #3 from the 1992 Yukon Utilities Board Cost of Service Report, and continues to be approved as appropriate by Yukon Utilities Board. For example, in its Order 1996-7, the Board noted that the allocation was consistent with past practice and "continued to be appropriate". Yukon Utilities Board Order 1996-7, page 6 http://yukonutilitiesboard.yk.ca/pdf/Board%20Orders%201990/63_boardorder1996_7.pdf The same method remains in place today.

[10] A comparable example for Manitoba Hydro is Bipole III as reviewed below. The line, once in service, may be used in a manner that appears indistinguishable from Bipoles I and II. However, this does not change the economic identity of Bipole III, as a distinct asset driven by different facts and load than the original Bipoles I and II.

[11] Manitoba Hydro Regional Cumulative Effects Assessment Phase II, page 2.2-1.

[12] This example was reviewed with Hydro's witnesses during the workshop May 11, pages 117 - 123

weighting, as it is not a particularly flexible short-term demand resource). With respect to the second step in the allocation, regarding class participation in cost sharing, the only classes that can make use of the output of the plant, by government legislative restriction, are domestic users – as such it should be allocated only among the domestic users.

The concept of the economic identity of a cost also encompasses not just the decision to put the asset into service, but also the economic nature of the decision to forego other alternatives. It encompasses the key matters underlying a decision not just to proceed and invest, but to proceed in a particular direction in contrast to other viable alternatives.

To use a hypothetical example outside of the power sector, if a company requires transportation support for its employees, it may install a parking lot (high fixed cost, relatively low operating cost) or consider other alternatives such as providing subsidized parking at nearby commercial lots, or provide bus passes. If the parking lot is not the lowest life-cycle cost option, the decision may be swayed by the fact that the parking lot offers a projected ability to, at times, gain revenues from renting space to a complementary user, such as a local recreation facility or church on Saturdays and Sundays, which may lower the net cost of the parking lot below the other options. As a result, the company may choose, on an economic basis, to install a parking lot. While these rental revenues do not <u>drive</u> the decision to require transportation support in the first place (i.e., the parking lot is being developed for employees) the revenues are an inherent element of the economic identity of the asset – without these revenues, a different decision would likely have been made. If one was to look at the economic driver of the cost, it is peak daytime employees. But it would be incorrect to consider 100% of the cost of the parking lot as the fault of the employees, while considering the revenue from the church as some type of near costless 'found money' unrelated to the capital cost of the parking lot.

Similarly, the company may want to provide some specified number of spots to allow customers to also use the parking lot, as well as perhaps occasional limited church use during the week. In the evenings, when employee numbers are down, there is little to no cost driver caused by the added use by customers. During the daytime, however, serving this added customer load could only be achieved by incurring cost to expand the parking lot. As a result, the economic identity of the parking lot can be inferred to be tied primarily to use at peak times, and much less if at all to use at non-peak times. The parking lot's economic identity is not driven by generic use of "space-hours", it is driven by peak weekday space availability.

In this non-utility example, one would obviously not apply utility COS calculations. However, if one were to apply utility COS principles to the total parking lot costs, it should be considered a shared asset (i.e., not directly allocated to one user group), with its costs shared largely based on use at peak times (i.e., coincident peak, though a lesser allocation to off-peak use may be appropriate if some of the costs are driven by this use, such as lighting). The participating classes sharing in the cost allocation should be all

users, based on their peak time usage. In this situation the vast majority of the costs would be allocated to the employees, though they would benefit from the fact that not 100% is allocated to them due to the shared responsibility of the customers and the church users who are present at peak times.

It is important to recognize that this COS approach should not be used to calculate the actual rates charged to the church use. This is a market service that should be provided at whatever price the market will bear. Consistent with this non-core service, the ongoing decision, week-by-week, whether to provide spots to the church should not be assessed based on this type of embedded cost allocation, but rather a simple incremental analysis – "does the church pay more each week than the incremental costs of their use (e.g., wear-and-tear)?". If the revenues exceed incremental cost, the lot should be made available.

Finally, a separate consideration, which should not be core to COS analysis, is trying to calculate the profitability of the church use to the company. This should not be based on the church covering its share of embedded costs. For this type of profitability analysis, one would likely need to review retrospectively the decision to proceed with a parking lot in the first place versus the alternatives of bus passes and subsidized commercial parking. The church use would be "profitable" to the extent that the revenues paid by the church continued to ensure that the decision to go with a parking lot remained the most overall economic choice (net of church revenues) to provide employee transportation support compared to the other alternatives.

The above example, while limited (as all analogies are ultimately limited), can provide some insight into COS considerations for Hydro's system.

2.4 OTHER CONSIDERATIONS FOR COST OF SERVICE PRACTICE

A further consideration that can help guide Cost of Service methodology is by reference to the broader utility industry practice. While there are always limitations in fully matching the factual basis of any other utility, the industry can provide comparisons of useful best practices and, while not determinative, this should be considered in deciding on methods to use for Manitoba Hydro. Unfortunately, Manitoba Hydro has not conducted any recent survey of COS methods for comparable utilities.[13] The record does include the Hydro-commissioned NERA survey from 2004[14] which, while dated, can provide some useful insight as methods typically do not change dramatically over time. Also, there is a publically available survey recently conducted by Leidos for BC Hydro[15] covering utilities broadly comparable to Manitoba Hydro.

[13] Transcript from May 12 workshop, pages 399 – 402.

[14] PUB-MFR-1

[15] As mentioned in MIPUG-MFR-9: BC Hydro 2015 Rate Design Application, Appendix C-2A, Leidos, Inc., Cost of Service Methodology Review, (December 20, 2013), Available online as an appendix to the 2015 BC Hydro RDA: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/2015-rda-appendices.pdf

Finally, it must be noted that the output of a COS study is a measure of the underlying costs of the system to each class, as well as by use (e.g., cost per customer month, cost per kW of demand, cost per kW.h). This data is useful in not only knowing the magnitude of costs to serve each class, but also in rate design considerations related to each component of the rate. Two issues arise in this regard:

1) It is not only important to get the right classification in the study to ensure customers receive the right overall dollar cost allocation, but also to ensure the robustness of these unit cost measures.

2) These numbers will only be reliable to the extent that they focus on credible measures of embedded cost. Manitoba Hydro's COSS is cited to also include other "goals" which are not related to measuring costs. Hydro's cited goals for the COS study, in section 4 of their main review filing, include some appropriate and standard Cost of Service measures, notably, 4.1 (Recovery of Revenue Requirement), 4.2 (Fairness and Equity) and 4.6 (Simplicity). However the other items cited (4.3 Rate Stability and Gradualism, 4.4 Efficiency and 4.5 Competitiveness of Rates) are not appropriate considerations during the Cost of Service analysis. While these items may be relevant to subsequent Rate Design steps, mixing these concepts in with the analytical COS study, Hydro is incented to modify what would otherwise be the correct and appropriate cost allocation approaches in order to manage the end results which undermines the accuracy of the COS study.

3.0 ALLOCATED COSTS IN PCOSS14-AMENDED - PRIMARILY BULK POWER

For the majority of Hydro's costs, there is a common or concurrent use or benefit to multiple classes, requiring a method of allocating the costs across all relevant ratepayer groups. This requires that four items be resolved for each cost category:

1) The cost must be functionalized to generation, transmission, distribution, customer service, etc.
2) The cost must then be classified to the type of use that drives the cost – typically to demand, energy, number of customers, etc.
3) A method of allocation must be identified for each classified cost (e.g., to every kW.h consumed, to winter peak, or to average summer/winter peak, etc.)
4) Finally, the subset of participating classes to which allocation occurs must be identified for each cost category.

This section focuses on issues arising from Hydro's PCOSS14-Amended, and does not present an overview of every cost category. The main issues addressed are:

- Generation Classification and Allocation
- Transmission Functionalization, Classification and Allocation
- Class Participation – Exports
- Customer Service General Allocation - C10

3.1 GENERATION CLASSIFICATION AND ALLOCATION

Hydro functionalizes all assets associated with producing power as generation, which is reasonable and appropriate. This includes all hydraulic generating stations and thermal stations.

Issues arise with respect to Hydro's approach to classification and allocation. In this regard, one major aspect of Hydro's approach does not reflect normal industry practices, which is the use of a 100% energy classification for all hydraulic and thermal assets.

In planning and constructing a power system, a major requirement is that the system be able to fully satisfy both the energy requirements of the system and the peak demand requirements. In the case of systems with primarily thermal generation, any generating complement that can meet the highest peak can usually meet all required seasonal/annual energy requirements. A hydraulic based system, however, will typically have additional energy planning constraints related to the annual or seasonal water flows,

and the amount of usable storage. As a result, hydraulic utilities will have a detailed planning system addressing both peak demand and energy.[16]

In the case of Manitoba Hydro, this planning occurs in a document known as the Power Resource Plan.[17] Within the Power Resource Plan, all Manitoba Hydro resources that supply the two distinct products – energy and winter peak demand – are listed along with all commitments to derive the calculated surplus/shortfall by year. For energy purposes, the surplus/shortfall measurement is based on extreme drought.

With the exception of wind purchases, all Manitoba Hydro power resources are included in both system planning tables (energy and peak winter demand). Wind purchases are only included in the energy tables, as they are not considered to provide reliable winter peak demand.

Consistent with standard Cost of Service practice, this indicates that Manitoba Hydro's resources (other than wind) provide two concurrent services. The appropriate consideration for classification is therefore based on a mix of these two services (with the exception of wind, which should be classified 100% to energy).

3.1.1 Manitoba Hydro Practice

The current Manitoba Hydro practice for generation classification is to classify all costs 100% to energy, and allocate on the basis of marginal cost weighted energy. The marginal cost weightings are derived from recent Surplus Energy Program prices (a measure of short-run marginal cost of using power from period to period).

Hydro acknowledges that past Manitoba COS methods explicitly recognized peak demand via classification, but indicates that this is no longer required as the current practice "implicitly considers a demand component as well as an energy component".[18]

While this energy weighting method has been used for a number of years, Hydro is now proposing to increase slightly the weighting of the peak periods, as there was concern raised by Christensen Associates[19] that the marginal cost values used by Hydro may under-represent the market value of

[16] PUB/MH-I-23b

[17] For example, see the 2012/13 Power Resource Plan filed as part of the NFAT proceeding, or the updated tables provided in Appendix 11.48 of the 2015/16 GRA.

[18] PUB/MH-I-42c

[19] Christensen Associates Energy Consulting ('CA') were hired by Manitoba Hydro to evaluate Hydro's COS methodology in 2012 and provided a supplemental report in 2015 on issues that have arisen since the 2012 report.

capacity. Mathematically, this led to Hydro increasing the weighting across each of the four seasonal "on-peak" periods in the marginal cost weightings.

3.1.2 Analysis of Hydro Marginal Cost Weighted Energy Allocation

Manitoba Hydro's approach to using marginal cost weighted energy as an allocator is a directionally appropriate modification to the previous unweighted energy allocation, which did not distinguish kW.h based on the time they were used (pre-2006). The use of SEP pricing, which is a short-run measure of marginal cost, gives a reasonable directional signal as to the value of energy in different periods.

The weighted allocator is solely a means to import the concept that energy in certain time periods is more important/relevant/valuable from the perspective of the cost drivers of Hydro's own system than energy used in other periods.[20] Since Hydro's costs are largely fixed costs arising from investments made over very long horizons, a theoretically superior method would be to use a credible long-run marginal cost for each of the time periods. However, this is clearly impractical for both robustness (i.e., due to forecast error, lack of precision to differentiate Hydro's long-run forecasts into 12 time periods) and transparency (i.e., due to confidentiality of Hydro's forecasts). In contrast, the short-run marginal cost measure is transparent, readily available, and directionally appropriate as a representation of the weighting of long-run marginal costs. As a result, the use of a short-run marginal cost is appropriate in the circumstances.

It is important to recognize that the allocator is not being used to suggest Hydro is trying to impose export market pricing on domestic customers. This is not the case. In particular, Hydro clarifies in the response to PUB/MH-I-62a that the short-run marginal cost of energy based on recent SEP prices is on the order of 2.0 to 2.5 cents/kW.h for the various classes (i.e., well below the scale of costs being allocated for Hydro's bulk power system of closer to 4 cents/kW.h).

This weighted energy approach is appropriate as a means to allocate all generation costs which are classified to energy, as this approach recognizes that kW.h's consumed at different times are not equally important to driving system costs.

3.1.3 Generation Capacity Costs

The largest issue with Hydro's proposed generation classification and allocation approach is the failure to classify most generation to capacity in any way.

[20] This is illustrated clearly by the fact that Hydro's own costs (revenue requirement) are the cost values being allocated – not the costs of external market sources.

This concept was reviewed with Mr. Cormie at page 153 of the May 11 workshop transcript, where it was noted that even in the case of generation resources such as wind, which have no capacity benefit whatsoever, the value of energy varies with the time period. In this instance, 100% classification to energy, and allocation using marginal cost weighted energy values is appropriate.

For all other Manitoba Hydro resources, the generation resources provide a combined energy and peak capacity product and the classification process needs to reflect this. For these resources, 100% classification to energy, even weighted energy, is not appropriate.

Manitoba Hydro asserts that the weighted energy approach is not only reflecting the value of energy, but also implicitly including demand considerations through the weighted energy allocator[21] and that the implicit percentage of demand is approximately 20%.[22] Hydro has also noted the conclusions of Christensen Associates that the use of short-run marginal costs in a market where capacity is separately traded may undervalue the importance of capacity if only short-run marginal energy costs (i.e., SEP prices) are used. As a result, Hydro has elected in PCOSS14-Amended to incorporate an additional peak period premium weighting tied to the capacity value that Hydro calculated is inherent in the Curtailable Rate Program.

The Hydro approach is not a reasonable representation of the costs of the generating system, for a number of reasons:

1) As noted above, the varying value of energy over time is not inherently a capacity related factor. As such, Hydro's contention that marginal cost weighted energy implicitly includes capacity does not bear out. Just because different energy time periods are proposed to be weighted differently, this is not necessarily the same load drivers that lead to capacity responsibility. The wind example above shows this point clearly – wind has no capacity component whatsoever, but the timing of the energy from wind across the various time periods would <u>still</u> lead to a varying value of the wind output.

2) The Christensen Associates report raises concerns about the SEP pricing failing to capture the MISO costs of capacity and operating reserves. This is a reasonable, though minor, concern. However it entirely misses the major concern that capacity as a generation cost driver (as well as a transmission cost driver) is not about the export market valuation of that capacity. The inherent value (and investment) in capacity is about meeting the absolute highest, short-term system pressures imposed in the extreme highest load hours. Every utility has detailed planning,

[21] PUB/MH-I-42c.

[22] Manitoba Hydro COSS workshop, May 11, 2016, transcript pages 324 - 325

operating, maintenance and contingency considerations that drive the ultimate ability to keep the lights on in the worst annual conditions, including conditions worse than expected (e.g., with unplanned outages, at peak times, under lower than expected winter temperatures). This includes everything from maintenance scheduling, to careful attention to equipment availability in addition to capital investment. Generation assets are a key part of this planning, and across the industry are the basis for substantial investment in reliability. In Manitoba Hydro's case, the NFAT filing, Chapter 13 (pages 25 - 28) discusses in detail that one of the benefits of the Preferred Development Plan is the ability to better carry peak loads (focused on MW, not a generic energy measure across large number of hours). Hydro associated a value to the Preferred Development Plan in excess of $101 million (NPV) compared to an All Gas scenario primarily due to added generation. This type of factor can only be caught in Cost of Service allocation via a properly constructed demand classification and coincident peak allocator for a portion of generation costs.

3) A good measure of why the Hydro marginal cost weighted energy does not capture proper peak demand considerations is that the winter peak hours that are all equally weighted in Hydro's model total 661 hours.[23] In other words, to the extent that Hydro's model is trying to capture a peak demand driver, it is using an exceedingly coarse measure based on the average peak over 661 winter hours which is far too many, and mutes the intended signal. As an example of the ineffectiveness of this measure, the residential average peak across the 661 winter peak hours is 1,471 MW[24], versus a class peak of 1,863 MW per Schedule D5 (and even 1,863MW as a peak mutes the true cost responsibility of the single extreme hour that Hydro must plan for by averaging the residential peak across 50 high load hours).

4) Finally, the Curtailable Service Program peak-period premium weighting approach proposed by Hydro in response to the Christensen Associates report is highly inferior, in that it applies the weighting equally to all peak hours in <u>all</u> seasons. The effect is to equally weight approximately 2000 hours spread throughout the year as equal contributors to the generation capacity cost drivers.[25] Hydro's system is clearly under varying degrees of load pressure in these seasons, with winter being clearly the most acute, and there should be no basis for spreading the weighting of any capacity premium this broadly.

Though there are limits to rote comparisons of Cost of Service methods across jurisdictions, it should be noted that no other jurisdiction in the NERA survey of comparable utilities completed for Manitoba

[23] PUB/MH-I-31a-c
[24] PUB/MH-I-31a-c, page 5.
[25] PUB/MH-I-31a-c

Hydro[26] in 2004, nor in the recent BC Hydro commissioned survey[27], classifies 100% of generation plant to energy.[28] This is consistent with the premise that peak demand needs to be recognized as a partial driver of plant investment.

An appropriate approach to generation classification should include a notable proportion of generation costs classified to demand. A common approach previously used in Manitoba is the System Load Factor method. Christensen Associates, in their 2012 report, highlights another common approach, the Equivalent Peaker method. Neither method has been fully explored for implementation in PCOSS14-Amended. Manitoba Hydro provided coarse estimates of an Equivalent Peaker method in the response to PUB-MFR-17, page 101, estimating the demand component to total 23% of generation costs. This is largely consistent with the previous System Load Factor approach from before 2006, which used 21.2% of Hydro's generation costs as demand-related.[29]

For the purposes of the current Cost of Service review, an appropriate classification of generation costs to demand should be established in the range of 21 - 23% and Hydro should be directed to consider alternatives to more precisely refine this percentage. Consistent with a winter peak capacity constraint in Hydro's planning, these costs should be allocated on the basis of the winter 1 CP, as per Schedule D1. The remaining generation costs should be classified to energy and allocated on the basis of the marginal cost weighted energy from PCOSS14 (i.e., without the extra Curtailable Rates Program adder used in PCOSS14-Amended).

The only exception should be wind purchases, which should be classified to 100% energy, and allocated on the same basis as all other generation energy costs.

3.2 TRANSMISSION FUNCTIONALIZATION, CLASSIFICATION AND ALLOCATION

Manitoba Hydro's PCOSS treats transmission assets in one of three ways:

1) Some transmission assets are treated as network transmission, functionalized to "Transmission" and classified to peak demand (allocated via allocator D14[30] which is based on 2 CP).

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[26] PUB MFR-1

[27] BC Hydro 2015 Rate Design Application, Appendix C-2A, Leidos, Inc., Cost of Service Methodology Review, (December 20, 2013), Available online as an appendix to the 2015 BC Hydro RDA: https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/regulatory-matters/2015-rda-appendices.pdf

[28] Leidos, Inc. COS Methodology Review for BC Hydro's 2015 Rate Design Application, Appendix C2-A, page 109 of 439. This survey highlights that four utilities use "Energy Only" for some components of hydraulic generation resources, but Manitoba Hydro is the only one of the four listed as using this Energy Only approach for plant-in-service.

[29] Per Board Order 7-2003, pages 42 - 43.

[30] There are a very small amount of operating costs allocated using the D13 allocator, but this appears to solely relate to MISO fees and does not otherwise affect functionalization or classification.

2) Another large group of transmission assets are treated as Generation Related Transmission Assets (GRTAs), functionalized to "Generation" and classified in accordance with the underlying generation (i.e., proposed at 100% energy, ultimately allocated via the marginal cost weighted energy allocator E12).

3) A small group of transmission costs related only to US interconnections are functionalized as "Transmission" but classified 100% to energy consistent with the way generation is treated (allocated via E15).

In effect, both items 2 and 3 above are similarly treated through the common allocators (E12 and E15 use the same rateclass weightings), in a manner more consistent with being functionalized as generation or power supply, rather than as typical transmission.

Normal Cost of Service practice, as set out in the various texts and utility practice, as well as in the NARUC manual "Electric Utility Cost Allocation"[31], is that the vast majority of transmission assets are functionalized to transmission and classified to peak demand (outside of a small exception for GRTAs which is only occasionally used). This includes every utility studied by NERA in the 2004 survey commissioned by Manitoba Hydro[32], as well as the asset costs for the majority of utilities surveyed by Leidos recently for BC Hydro.[33] The NARUC manual in particular notes that transmission costs "are generally fixed costs that do not vary with the quantity of energy transmitted"[34] and thus are demand-related. One exception is noted by NARUC in that transmission developed to help avoid line losses may merit a portion classified to energy, which is of minor relevance to Hydro's transmission assets.

The one common special case in transmission functionalization is related to GRTAs (also known as Generation Step-Up Facilities). This category comprises a limited set of assets which function as generation leads between the generator and typically the first switchyard. To take the example of BC Hydro, the GRTA category is used to capture a limited subset of transmission lines ("the GRTAs include the 500 kV transmission system north of Williston and east of Nicola and Ashton Creek"[35]). In the case of the northern parts of the province, only the lines from Shrum GS to Prince George, BC are considered GRTAs and not the major transmission linking northern BC to the southern grid. Critically, this entire GRTA category for BC Hydro makes up only $43.3 million of annual costs for COS purposes, out of an $888 million transmission revenue requirement, or less than 5%.[36] Though the GRTA practice is

[31] National Association of Regulatory Utility Commissioners (NARUC), (January, 1992), Electric Utility Cost Allocation Manual
[32] Re-filed as PUB-MFR-1, pages 2 - 4
[33] BC Hydro 2015 Rate Design Application, Appendix C-2A page 95 of 439
[34] National Association of Regulatory Utility Commissioners (NARUC), (January, 1992), Electric Utility Cost Allocation Manual, Chapter 2: Overview of Cost of Service Studies and Cost Allocation, page 21
[35] BCUC-G-43-98 page 9.
[36] BC Hydro 2015 Rate Design Application, page 3-13 to 3-14.

commonly used as a step in functionalization – that is, treating some transmission as part of the generating complement – the practical effect is normally that this functionalization means the resulting assets are then classified and allocated consistent with the underlying generator rather than in a manner more typical for transmission.

In the case of Manitoba Hydro, the Cost of Service study incorporates not only generator leads in the GRTA category (e.g., Long Spruce to Henday) but also the entire Bipole I and II DC transmission system itself, including the DC conversion components of the Dorsey station.

3.2.1 The Appropriate Use of the Generation Related Transmission Concept

In order to suitably test whether a transmission or substation asset qualifies as a GRTA, it is reasonable to apply certain criteria to the asset. In the first instance, it must be recognized that the normal transmission function can readily incorporate facilities that are focused on moving bulk power from one location to another, including from generation sources, as well as those that operate largely if not exclusively in a single direction of power flow. As noted by FERC:

> The Federal Energy Regulatory Commission defines a transmission system to include: (1) all land, conversion structures, and equipment employed at a primary source of supply (i.e., generating station, or point of receipt in the case of purchase power) to change the voltage or frequency of electricity for the purpose of its more efficient or convenient transmission; (2) all land, structures, high tension apparatus, and their control and protective equipment between a generating or receiving point and the entrance to a distribution center or wholesale point; and (3) all lines and equipment whose primary purpose is to augment, integrate or tie together the sources of power supply.[37]

This definition readily incorporates the concept of integrating generating stations, and changing the nature of the station output for the purposes of more efficient or convenient transmission.

To support its conclusion that Bipole transmission should not be functionalized as transmission, but rather generation, Hydro has long suggested the use of criteria consistent with the "FERC 7 factor test", which

[37] 1 FERC Para, 15,064, as cited in National Association of Regulatory Utility Commissioners (NARUC), (January, 1992), Electric Utility Cost Allocation Manual at page 69.

was the primary rationale at the time the GRTA treatment of Bipoles I and II was adopted in 2001.[38] Hydro used this test to conclude that Bipoles were not appropriately included in the calculation of Hydro's transmission tariff and consequently proposed that they also not be included in the transmission function for the purposes of Cost of Service analysis.[39] Based on this same analysis approach, Dorsey converters were treated as transmission. However, the cited 7 factor test is generally not a test for the division between generation and transmission; it is a test for the division between transmission and distribution. As such, the criteria are poorly suited to assessing the generation interface with transmission.

Christensen Associates provided a description of GRTAs in their 2012 report, where they noted: "It is common practice to consider transmission interconnection facilities as generation-related, where the facilities are specific to interconnection and the costs are thus assignable. However, the distances are generally short and thus do not involve the provision of transport services."[40] Christensen Associates goes on to identify four criteria that they indicate as important to the determination:

1) Are observed flows on the facility representative of the net of numerous counterflows between points of power injections and load withdrawals?
2) Are flows on the facility of a uniform direction?
3) Does the facility provide improved reliability for the AC meshed network as a whole, in isolation of any specific generation facility?
4) Does the facility provide increased power flow capability to the AC meshed network?[41]

By the time of the Christensen Associates 2015 COS report, the criteria had been reframed in the case of determining the appropriate functionalization of the new Bipole III investment:

1) Long-term supply reliability that parallels investment in MH's northern generation services,
2) Single directional flows,
3) Distinguishing operating characteristics [presumably the DC nature of the line, which leads to more controls on "power injection" and no load withdrawals or injections along its length], and

[38] For reference, the FERC 7 factor test on page 4 is as follows: "The Commission proposed seven indicators of local distribution to be evaluated on a case-by-case basis: (1) Local distribution facilities are normally in close proximity to retail customers. (2) Local distribution facilities are primarily radial in character. (3) Power flows into local distribution systems; it rarely, if ever, flows out. (4) When power enters a local distribution system, it is not reconsigned or transported on to some other market. (5) Power entering a local distribution system is consumed in a comparatively restricted geographical area. (6) Meters are based at the transmission/local distribution interface to measure flows into the local distribution system. (7) Local distribution systems will be of reduced voltage." http://psc.state.wy.us/htdocs/subregional/SynopsisFERCTrans.pdf

[39] In particular, see MIPUG/MH-II-21(R) from the 2001 Status Update proceeding (March 15, 2002).

[40] Appendix 5, Christensen Associates (June 8, 2012) Review of COS Methods, page 13

[41] Appendix 5, Christensen Associates (June 8, 2012) Review of COS Methods, page 14

4) Close integration to MH's generation facilities in the north.[42]

The Christensen Associates criteria are interesting but do not appear to be determinative nor fully appropriate to the case of Hydro's Bipole system. In particular, investment in transmission that increases reliability and parallels investment in generation would be a common factor in any transmission development. Similarly, the concept that Bipole I and II loading levels are not the result of readily changing loads imposed on the system are not supported by the evidence. As Hydro's witnesses noted at the May 12 COS workshop, most load following is now done using the DC system with load changes occurring in the timeframe of minutes.[43] It is acknowledged that this is not near instantaneous changes, as occur in an AC system, but it is not apparent why this distinction of seconds versus minutes has any relevance (much less be determinative) as to whether an asset is fundamentally transmission in nature versus generation, nor why it ultimately should be allocated as an energy resource versus on the basis of capacity. If anything, this reasoning shows an over-focus on tests of use or operation, rather than on the investment rationale and purpose.

A reasonable set of criteria to determine whether an asset is a GRTA should fundamentally be based on the concept of a "but for" test applied to the decision to invest in the asset – that is, a GRTA exists when, but for the identified generation, the transmission asset would not exist (i.e., have no other justifiable role, and no alternative would be required) and but for the transmission component, the generation would not exist (i.e., have no means to get its power to delivery locations). Further, the cost of the transmission asset should be the minimum practical to fulfill the "but for" requirement. The cost should also be sufficiently material to bother with the exceptional functionalization as generation. A very practical application of this principle is that the lines in question should be integral to the business case to proceed with the generation, and should be developed concurrently with the generation.

This GRTA concept is not perfectly determinative – there can be some degree of uncertainty with respect to any such treatment – but that is why this more creative functionalization approach should only be used in a limited number of circumstances that fully satisfy the test. Where there are network features, or multiple roles played by a transmission component, the asset should be functionalized as transmission consistent with its core nature.

The issue for Hydro's PCOSS14-Amended is which assets pass or fail this test:

1) **Generator outlet transmission:** This would apply to situations, such as the Keeyask Outlet transmission under construction. These assets would pass this test for inclusion in the GRTA

[42] Appendix 2, Christensen Associates Supplemental Report (August 10, 2015), page 12
[43] May 12 Hydro COS workshop transcript, page 582

category. These assets are integral to Keeyask, were considered as part of the business plan to proceed with Keeyask, the generation station would not have proceeded without these assets, and the assets would not have been needed for any other role on the system but for the development of Keeyask. Similarly, Limestone and Long Spruce outlet transmission (to the Henday and Radisson stations) are appropriately GRTAs. An outlier in Hydro's analysis appears to be the Wuskwatim outlet transmission, lines W1, W2 and W3 comprising about $3.4 million of average rate base.[44] It appears these lines are not currently considered to be GRTAs, but the underlying circumstances would appear to support this line segment in the same manner as the other outlet transmission.[45]

2) **Bipole I and II lines:** These assets pass the test for treatment as a GRTA. The lines were integral to the decision to proceed with the LWR/CRD project (and in particular, Kettle, Limestone and Long Spruce generating stations), and were considered as part of the economic evaluation to proceed with that complex development. The three plants in question would not have been developed without Bipole I and II, and Bipole I and II would have no purpose without the three Generating Stations. The development of the transmission and generation occurred effectively concurrently.

3) **Dorsey converter:** The Dorsey converter station is a more complicated assessment, and as such should likely not receive the GRTA designation. In particular, it has been long recognized that Dorsey's DC conversion function is solely used to support Bipoles I and II (which would act in support of Dorsey as a GRTA). However, it has also been recognized that Dorsey's converter components play a necessary role in supporting the AC system, and at the time of the 2001 Status Update proceeding, were included in the Hydro Transmission Tariff.[46] This is important, as inclusion in the transmission tariff means that external parties seeking to transmit power through Manitoba (i.e., not for use serving Manitoba load), despite no use of the Bipole I and II system, are still allocated a share of the Dorsey converter facilities as these facilities were considered to provide these transmission customers with benefits. Hydro noted as follows:

> "Without the flexibility in control associated with the HVDC system, Manitoba Hydro would have had to make a much greater investment in its AC transmission system to provide the equivalent transfer capability provided through the HVDC system today. Hence the Dorsey converter station is included as part of the

[44] Per Hydro's COSS excel file "Cost Details Transmission and Substation.xlsx"

[45] This does not apply to lines W73H, W74H and W76B which are major 230 kV lines connecting Herblet Lake station to Birchtree via Wuskwatim on the transmission side of the Wuskwatim substation.

[46] It appears this may still be the case, that Dorsey assets are part of the Hydro Transmission Tariff assets.

> transmission tariff because its operation primarily benefits all transmission customers through the special features of the HVDC system."[47]

Christensen Associates also considered the role of Dorsey in supporting the AC system in a manner that would have to be replaced by other equipment if the Dorsey converter did not exist. CA ultimately convinced Hydro to conduct a detailed study of the value of this benefit, focused on the "Special Protection System" (SPS). Christensen Associates concludes that the SPS "enables MH to satisfy transient stability limits at moderate to high system loadings, at remarkably reduced costs compared to other control methods to maintain stability."[48] However, CA approached the issue from a fundamentally different premise than the earlier Hydro approach; that is, CA focuses on the basic assumption that Dorsey converters are part of the Bipole I and II package and thus should be functionalized to generation by default. This is an incorrect starting point, inconsistent with Hydro's previous (and still prevailing[49]) logic, and inconsistent with the premise that has been previously accepted by the PUB.

Christensen Associates also effectively ignores their own conclusion that the benefits of Dorsey arise most notably at "moderate to high system loads" with their recommendation that more of the project costs should be functionalized to generation, which ultimately results in costs being allocated on the basis of energy, rather than on the demand peaks which they cite as primary benefit of this HVDC characteristic. Finally, CA concludes that the Dorsey station converter costs should be apportioned between generation and transmission, which is fundamentally at odds with the premise of GRTAs, in that the category is meant for assets that are not of value except for the purposes of their generation role (i.e., it is not suited to mixed-role assets).

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[47] MIPUG/MH-II-21(R) from the 2001 Status Update proceeding (March 15, 2002).

[48] MH filing, Appendix 2, page 13.

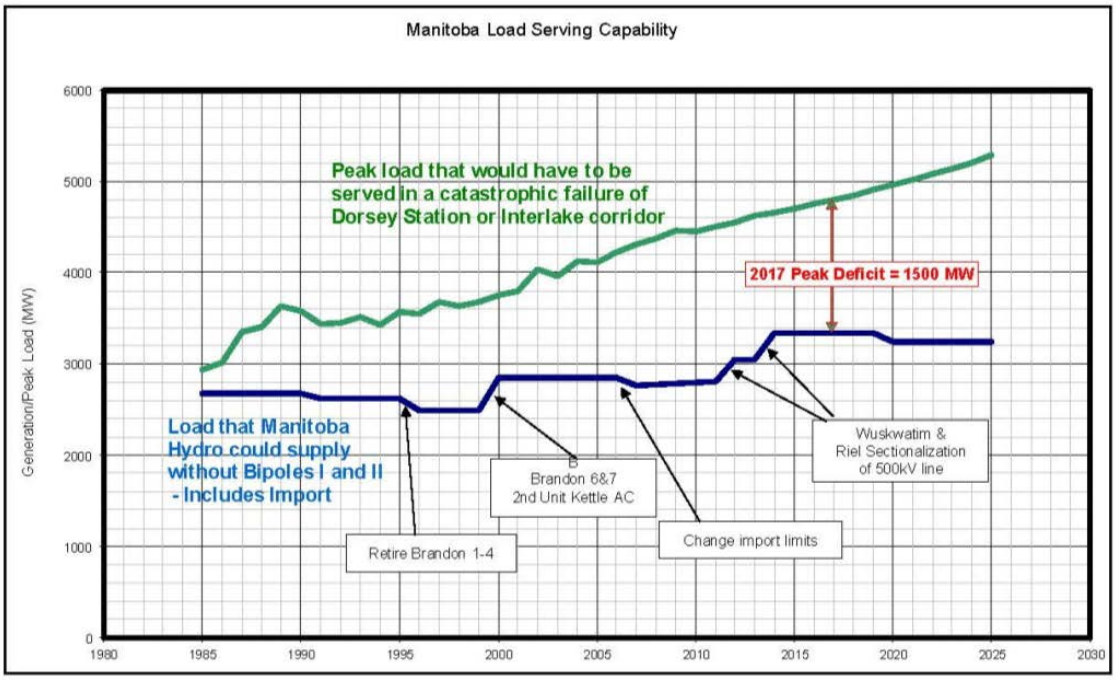
[49] With respect to the transmission tariff, the available evidence appears to indicate that Dorsey DC facilities are included in Hydro's recent transmission tariff. Hydro's OATT effective January 1, 2015 is available online: http://www.oasis.oati.com/woa/docs/MHEB/MHEBdocs/MH_OATT_Version_35_Jan_2015.pdf with Attachment O providing the Transmission Revenue Requirement used for tariff calculation based on the fiscal 2010 year. The depreciation expense is $53.3 million and operating expense is $65 million. As an approximate, PCOSS10 is also based on the fiscal 2010 year, where Transmission functionalized operating expense is $53.8 million (from Schedule C12) and transmission functionalized depreciation expense is $51.2 million (Schedule C6). In other words, the Transmission Tariff uses higher depreciation and operating costs than PCOSS10. PCOSS10 included Dorsey Converter Station in the Transmission Functionalized HVDC & Collector Facilities expense, which makes up approximately half of total revenue requirement for depreciation and a third for operating expenses. It is assumed Dorsey makes up all or most of these cost functions based on Hydro's 'Specific Cost Details_Bipoles and Dorsey' tab which shows annual costs for Dorsey Converter Station in 2013/14 at or above these amounts. While PCOSS10 is only a proxy for the OATT Revenue Requirement, the amounts without Dorsey portions would be off by a very large magnitude from the OATT revenue requirement, leading to the conclusion that at least for the January 1, 2015 transmission tariff, Dorsey Converter Station is very likely included. Were it not included, it is not clear how the transmission tariff revenue requirement is as high as cited in Attachment O to the tariff, by a considerable margin.

Since it appears there has been no change in the inclusion of the Dorsey HVDC assets in the transmission tariff, and there appears to be no debate that the Dorsey conversion station continues to provide some value to the system beyond purely converting DC power to AC, and given the high standards that should apply before electing to treat transmission assets as generation, it does not appear appropriate to functionalize Dorsey to generation at this time. The Dorsey converter should be functionalized as transmission, and classified and allocated consistent with the other components of the transmission system.

4) **Bipole III and Riel Converter:** The Bipole III project, including the Riel converter, is a massive future cost item that will drive a substantial component of future PCOSS results. At its core, Bipole III is much like Bipoles I and II, with one highly distinguishing characteristic: Bipole III was not required for the development of LWR/CRD and the existing Lower Nelson River stations (which operated successfully for decades without the line). Further, Bipole III is not submitted by Hydro to be integrally linked to Keeyask and future generation in terms of the fundamental business case for these projects (hence its exclusion from the NFAT proceedings, as a project that was determined to be justified to proceed regardless as to the conclusion on development of Keeyask or Conawapa). In short, Bipole III is a project that is not driven by generation and as such fails the “but for” test. Bipole III is driven by load growth.

The case for Bipole III is set out in detail in the project justification prepared by Manitoba Hydro, and submitted to the Clean Environment Commission (Exhibit MH-21). That document clarifies that the fundamental driver for Bipole III is growth in Manitoba load and ensuring reliable service at peak load hours. Figure 2.2-1 of that document illustrates that at the highest of the Manitoba winter peak loads, the total power that could be supplied absent during a Bipole I and II outage (or Dorsey outage) is now approximately 3,400 MW.

Figure 1: Manitoba Load Serving Capability without Bipoles I & II from MH-21 (Figure 2.2-1)



Up until the mid-1990s, approximately 20 years after Bipoles I and II were put into service, this would have been largely sufficient to marginally supply the Manitoba load, even at the peak winter hour. However, the facts have changed and today there is a peak winter deficit of over 1,500 MW in this situation (i.e., a Bipole I and II outage). This deficit means that the majority of hours in the winter peak period, as well as likely the winter shoulder period, may otherwise face supply shortfalls absent Bipole III.[50] Were Hydro's Cost of Service approach adopted for Bipole III, the net effect would be to charge the project across all time periods of the year consistent with the weighted energy allocator E12. This allocator places almost the same weighting on summer peak as on winter peak (5.870 versus 6.358), and weights peak fall and spring hours considerably higher than winter shoulder hours (5.372 and 4.966 versus 3.588), despite these non-winter time periods having little to no relevance to the decision to proceed with Bipole III. In fact, even winter off-peak average domestic demand, at 3,262 MW well exceeds the summer average peak period demand at 2,810 MW[51], and as such is far more relevant to the business

[50] Figure 2.2-3 from Exhibit MH-21 shows how in the peak month of January, up to 85% of the hours would see unserved energy in the event of a sustained Bipole I and II outage – however, in lower load winter months such as March, the number of hours would not be expected to be anywhere near this high.

[51] PUB/MH-I-31a-c, page 5

case for Bipole III, but under E12 is weighted less than half as heavily as the summer peak (2.691 versus 5.870).

It is also important to recognize that with Hydro's proposed treatment of Bipole III (as well as Riel), the post 2019 PCOSS (when Bipole III is in–service) will see almost 80% of Hydro's costs for transmission and high voltage substations functionalized as generation and classified 100% to energy.[52] This appears to be unprecedented among comparable utilities – with BC Hydro treating less than 5% of their transmission as GRTAs (the remainder is 100% demand classified) and Newfoundland Hydro showing a relatively high ratio at just under 25% (and further, of this 25%, a significant portion is still classified to demand consistent with the underlying generation, so the energy percentage of costs in the transmission-type assets is well below 15%).

In short, Bipole III fails to fulfill any reasonable test to be functionalized to generation as a GRTA. The Hydro proposal is not consistent with Bipole III's business case as a reliability project (not a generator outlet). The Hydro proposal leads to excessive use of the GRTA category compared to all identified peer utilities, and the ultimate allocation of the costs on the E12 allocator does not reflect the fundamental underlying cost causation for the Bipole III project.

On its cost profile, the driver of Bipole III is load imposed on the system during the winter season. A reasonable cost of service treatment reflecting this cost profile is functionalization as transmission, classification to demand and allocation on the basis of the winter 1CP (the measure that leads to the calculation of a 1,500 MW system deficit). Alternatively, to reflect the that the type of outage that Bipole III is intended to reduce, which is a possible long sustained outage causing disruption over many hours of the winter season, an alternative cost of service approach could be functionalization as transmission, classification to winter energy, and allocation on the basis of marginal cost weighted energy covering <u>only</u> the winter peak and shoulder periods. This is similar to E12 as proposed by Hydro, except that rather than weighting the full annual 8,760 hours according to their short-run marginal market value, the focus would be on only the 1,940 hours[53] making up the peak period of concern. Though this is not an industry standard approach, it reflects much better the economic identity of Bipole III then the current E12 proposal.

[52] This includes all costs functionalized to generation, as well as all costs allocated using allocator E15.

[53] Winter peak period plus shoulder period hours per PUB/MH-I-31a-c page 5 (661 peak hours plus 1279 shoulder hours)

The only detriment to this approach is that it serves to significantly reduce the export allocation of Bipole III which, while potentially cost justified, does happen to be inconsistent with the cited policy framework for the project that exports revenues would cover the costs of the project.[54]

The same conclusion noted above for Bipole III applies for Riel converter, given the impetus for the converter is entirely aligned with the Bipole III project.

3.2.2 Other Transmission Classification and Allocation Issues

In this PCOSS, Hydro is proposing a new classification of "US Interconnections" to 100% energy allocated on the basis of marginal cost weighted energy. The argument for this treatment is inconsistent with longstanding industry practice regarding transmission assets being classified to capacity, and in fact is also inconsistent with the way cost recovery occurs for these very same lines under Hydro's transmission tariff (which is based on CP)[55] and tariffs for the US counterparties owning the complementary line segments across the international border. While these lines at times pay a role to deliver energy during droughts, all transmission has this same function – to reliably deliver power from the most economic and available generation source from moment-to-moment. There is no compelling argument to treat these US interconnections (including presumably the future Manitoba-Minnesota Transmission Line and Great Northern Transmission Line) different than any other AC transmission (including interprovincial interconnections, which Hydro proposes to retain as classified to demand). Hydro's proposal to classify these assets as energy should be rejected.

3.3 CLASS PARTICIPATION - EXPORTS

Having functionalized, classified and allocated the bulk power costs to a set of allocators, it becomes necessary to identify which customer classes should participate in having these costs allocated to their load. In most cases, this identification is straight-forward. However, in the case of exports, there has been considerably more debate over the years.

A detailed history of the development and evolution of the export class is provided in Attachment B to this testimony. The history in that attachment highlights the first calculations of the costs to serve exports as a class in PCOSS06, the development of the class through PCOSS08 and Order 116/08, the

[54] In particular, the decision to proceed with the project, and specifically at a higher cost than alternatives, was justified as a policy position of the Manitoba Government which noted "Who's going to pay for Bipole? The export customers pay for it. You build the cost into the price of the product when you sell it to your customers" (Manitoba Premier, quoted in "Manitoba Hydro president indicates ratepayers may be on the hook for new hydro line" http://www.winnipegfreepress.com/local/Ratepayers-will-be-on-the-hook-for-new-hydro-line-Manitoba-Hydro-president-277488632.html .

[55] Hydro's OATT effective January 1, 2015 is available online: http://www.oasis.oati.com/woa/docs/MHEB/MHEBdocs/MH_OATT_Version_35_Jan_2015.pdf with Attachment O providing the Transmission Revenue Requirement and Tariff calculation.

ongoing changes proposed by Hydro since that time which have not been approved by the PUB, and reversed previous directions of the PUB.

At this time, Hydro has proposed a number of modifications of the treatment of export revenues in PCOSS14-Amended compared to the last PUB Order addressing Cost of Service issues. Most notably however, is the proposal to reassert that dependable exports should be allocated a full share of system fixed costs, but opportunity exports should only be allocated variable costs. This type of method was proposed by Hydro in PCOSS06 and raised by Hydro as an option in subsequent proceedings, and was rejected by the Board at least three times, in each of 117/06 *("…the Board finds it inappropriate to divide export sales into two classes, allocating only variable costs against one of the classes, the opportunity class…"* [56]), 116/08 ("*In making its closing submission, MH remained critical of Order 117/06's "considerable" cost allocations to the export class, particularly with respect to: …c) Degree of embedded costs going to both firm and opportunity exports (with MH contending that no fixed costs should be directed at opportunity sales in the export class). That argument by MH was heard and rejected by the Board…*"[57]), and 5/12 ("*Because export contracts and opportunity sales carry greater risks than domestic sales, such export sales must provide a contribution to MH's fixed costs.*"[58]). Despite this regulatory record, the idea has been reintroduced by Hydro as a proposal in PCOSS13.

Hydro supports its proposal to differentiate in cost treatment between dependable and opportunity exports sales as follows:

> The driver behind resources is the need to serve Manitoba load, in all conditions, at least cost. To meet Manitoba load reliably, Manitoba Hydro must put resources in place not only to meet annual energy requirements, it must also put resources in place to meet the energy needs of its customers in every hour of the year (demand) and these requirements must be met even in lowest flow conditions. The outcome of this planning is that surplus energy is available temporarily in a hydraulic facility.
>
> It is difficult, perhaps not possible, to precisely allocate cost to the export class given no facilities are driven by exports. To accommodate the allocation of cost to the export class for its intended purpose, Manitoba Hydro has elected to draw a distinction between the surplus energy types to recognize differences in the firmness, in other words differences in service levels.[59]

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[56] Order 117/06, page 51
[57] Order 116/08, pages 271 - 272
[58] Order 5/12, page 214.
[59] PUB/MH I-2b, pages 1 - 2

Hydro's above excerpt suffers from three significant issues:

1) The characterization that surplus energy is available "temporarily" from new hydraulic facilities may apply at best to dependable exports (which have not been at issue since 2006) but is entirely not the case for opportunity exports which are the key export type being debated. Regardless as to Manitoba load growth, the system will always have opportunity energy available for export under almost all water conditions, and this will be in ever increasing quantities as the system expands. This is because such opportunity energy is inherent to each added hydraulic plant, and domestic customers do not make any notable use of opportunity energy.

2) The test applied by Hydro focuses on the "service levels" provided to export energy. This is not the purpose of the export class in the Cost of Service study. The service level may be relevant to the pricing of the energy when making a sale, but as readily acknowledged in the preceding sections of this testimony, and repeatedly by Hydro, the use of an export class in the Cost of Service study is not for the purpose of setting export rates. The purpose is to ensure that export revenues are making a contribution towards the assets that their existence served to underpin. In short, the export class is a part of reflecting the economic identity of the generation and transmission facilities – and where this identity is rooted in the presence of export revenues (particularly permanent opportunity revenues throughout the asset's life) the opportunity sales should participate in funding the asset costs.

3) Also of note, the argument set out above by Hydro is indistinguishable from the argument used by Hydro in each COS review since 2006, which has now been rejected three times by the Board.

The reintroduction of the "2 export class" concept in the Cost of Service is all the more surprising given the degree of inconsistency between this approach and the overwhelming evidence in the recent NFAT proceeding.

The most relevant component of the NFAT evidence for the purposes of the Cost of Service study was provided in NFAT MH Exhibits 95, 104-8 and 104-5. These exhibits review how the concept of any capital intensive development, including the Preferred Development Plan (PDP), and "Plan 5" (the plan effectively ultimately approved, with Keeyask and a 750 MW transmission line) both hinged entirely on export revenues from all sources (dependable and opportunity). In particular, Plan 5's positive NPV of $410 million compared to "All Gas" incorporated over $8.7 billion in NPV of exports compared to only $5.2 billion under All Gas – an added export contribution of $3.5 billion NPV. Absent this added export contribution to offset the higher costs of the developments, there is no business case for Keeyask whatsoever compared to a simpler, lower capital cost thermal alternative (and similar analysis would be expected to fully confirm the same conclusion for Wuskwatim). In short, absent the full range of export revenues being credited to help pay for the high capital costs of adding hydro plants, these plants would

not have been developed in their current form. While Hydro is correct that this is not sufficient to say that exports "caused" the development of new generation, what Hydro has failed to note is that exports (including opportunity exports) in fact did cause that new generation to be a high capital cost hydraulic generation plant, as opposed to available lower cost alternatives.

It is not clear what additional analysis or data could be required to confirm the correctness of the PUB's conclusion on this matter in three sequential Orders on COS matters.

Based on the large quantity and integral nature of exports (both dependable and opportunity) to Hydro's system, all generation and transmission costs should be allocated on the basis that all exports participate sharing in the cost. The only exception should be the Brandon Coal plant.

3.3.1 Brandon Coal Generation

Climate change legislation contained in Bill 15, legislated that use of the Brandon Unit 5 coal generating station be limited to emergency use only after December 31st, 2009 and cannot include use for export purposes. Since Manitoba Hydro can no longer use coal-fired generation to support exports, all the fixed and variable costs were first assigned entirely to the domestic classes in PCOSS10.[60]

Manitoba Hydro's methodology for Brandon coal-fired generation was to assign only to the domestic pool from PCOSS10 to PCOSS14. In PCOSS14-Amended, Hydro has proposed to allocate these costs over domestic and dependable exports[61] (using the E12 allocator) for the rationale noted in the Hydro workshop:

> MS. KELLY DERKSEN: Well, the rationale for the change in the treatment of coal and PCOSS14 amended wasn't because we don't believe that that investment today, that resource today, is only intended today to serve domestic load. But it was more from the perspective of, I understand that there could be a perspective that -- and it's not an unreasonable one (1) that you can't stream electrons. So if we were in an emergency circumstance, and that facility had to be used to support power in the province, you know, I understand the perspective that you can't stream electrons. You don't know where that energy necessarily is going. And so from a simplicity perspective, I didn't think it was reasonable that we would continue down the path to try and debate what the role of that facility is at some point in time under some set of circumstances, put it all in the pool, and let's share the -- the cost responsibility between domestic and exports.

[60] PCOSS10 (November 30, 2009), page 7

[61] PUB-MFR 13, Tabular Progression for Prospective Cost of Service Study 2006 – 2014

> And it wasn't because we thought that that facility, from a technical perspective, was being used differently.[62]

The PUB does not appear to have provided direction on this topic since Order 116/08 (i.e., prior to the actual implementation of Bill 15) when it directed Hydro to assign all fuel costs and 50% of the fixed costs of the thermal and coal plants to the Export class, noting: "(w)hen Brandon Coal Generation is restricted to emergency use only (in accordance with the government's direction), the allocation of costs to the export class will decrease, assuming MH doesn't replace coal with natural gas generation (e.g., combined cycle combustion turbine)."[63] In short, now that the legislative restrictions are in place, it would appear to meet the PUB's directive and appropriate COS practice that Brandon coal no longer be allocated to exports.

3.4 CUSTOMER SERVICE GENERAL ALLOCATION METHOD – C10

Large industrial customers are allocated a share of the distribution service function via allocator C10 "Customer Service General". The total cost to industrials[64] is $4.987 million. Very little detail is made available about the C10 allocator in Hydro's PCOSS. PUB/MH-I-57 clarifies that the ratios for distributing C10 costs have not been updated since PCOSS11.

Information in MIPUG/MH-I-4a, indicates the composition including a number of smaller categories, as well as one category, "customer consultation and information", that made up more than half of the C10 costs. The undertakings from the workshop[65] finally begin to clarify the composition of this category. Ultimately, reviewing the total costs allocated via C10 and the ratios presented, it appears the industrial classes face costs for C10 Customer Service General as follows:

[62] Transcript from Manitoba Hydro COSS workshop, May 11, 2016, transcript pages 124 – 125
[63] Order 116/08 page 270
[64] GS Large >100 kV and 30-100 kV, in approximately equal shares.
[65] Hydro Undertaking from transcript page 791

Table 2: Customer Service General (C10) Costs Allocated to Industrial Customers[66]

$000s	GSL 30-100 kV	GSL >100 kV
Customer Engineering Services Inquiries	327	294
Key Accounts Department	137	758
Major Accounts Department	442	26
Municipal/Community Relations	46	91
Public Accountability (PUB hearings)	129	308
Power Quality	298	217
Service Extensions	152	17
Customer Policy	26	44
Rates and Cost of Service	128	202
Load Research	64	47
Customer Service (Other)	817	395
Total	**2,568**	**2,399**

It becomes extremely difficult to decipher the actual services being provided under each category beyond the very brief one line descriptors, nor any practical ability to test that the allocations between industrials and other classes is reasonable.

Most concerning is the category called "Customer Service" (noted above as "Customer Service (other)" as the entire C10 category is already entitled "Customer Service" in PCOSS14). This is the largest component of costs allocated to industrials on a dollar value basis (over $1.2 million), and the only reference to what this includes is in the Undertaking from transcript page 791, where it notes "Customer Service includes the costs related to line locates, safety watches, consumer consultations, building moves, and education/safety." On a normal basis, few if any of these services would relate to services to industrials, who already are allocated substantial amounts for staff involved in the direct daily communication and consultation with these customers through the categories of "Key Accounts" and "Major Accounts". Certainly the information provided to date, through two rounds of information gathering, does not substantiate $1.2 million in allocated costs for these five generic services. Absent

[66] Amounts are approximate (there appears to be rounding or a slight error in the percentage tables provided by Hydro) and were calculated as follows: From MIPUG/MH-I-4a class share percentages of total Planned Orders ($28.846 million) were calculated from 'Estimate of Class Share of Individual SCCs' multiplied by 'Percent of Total Planned' row in Planned Orders by SCC. This weighting (on a per class and per SCC basis) was applied to total C10 costs ($46.561 million) provided in MIPUG/MH-I-4b to split total C10 costs by SCC and rateclass allocation. This amount was multiplied by the percentage allocation of total planned orders of the total for each rateclass (i.e. percentage of total planned orders for each SCC by rateclass was calculated similar to above, and then this share as a percentage for each rateclass total costs was weighted by SCC) from the 'individual department estimates weighted by planned costs' provided in Hydro Undertaking from Transcript page #791 (page 2) to get allocated cost for each SCC by rateclass for C10. These class level totals approximately equal total allocated costs for C10 to GSL 30-100kV and GSL >100kV in the 'C Tables Proces' tab of Hydro's Model of PCOSS14 (Amended).

further compelling information from Hydro, there would appear to be no basis to allocate any of these costs to industrials.[67]

[67] It further appears, from the response to Undertaking Transcript page 791, that the category is allocated by a gross estimation which simply forces 1% to each industrial subclass other than the GS Large 30-100 kV non-curtailable subclass which gets a generic estimate of 3%. It is not apparent that this is an allocation based on any reasonable allocation technique, such as number of customers, but despite requests, Hydro has not provided any substantiation for these values.

4.0 DIRECTLY ASSIGNED COSTS IN PCOSS14-AMENDED

Costs that relate to only a single class of customers, or that can be broken into parts that relate to only a single class, are carved out of the costs in a Cost of Service study and directly assigned to the class that drives the cost. In the case of Hydro's Cost of Service study, there are relatively few costs that are directly assigned to domestic customers, primarily related to DSM. This section addresses directly assigned DSM costs in two parts:

- DSM undertaken for energy efficiency reasons
- The Curtailable Rates Program

4.1 DSM – ENERGY PROGRAMS

In PCOSS14-Amended Manitoba Hydro is proposing to assign Demand Side Management (DSM) costs that relate to energy efficiency directly to the customer classes participating in the program. This does not include expenditures on the Affordable Energy Fund (AEF) costs which are still being charged to the export class, reviewed in this evidence in Section 5.2.

Direct assignment to participating domestic customer classes was the approach used prior to PCOSS06. Order 117/06 concluded that DSM activities were a driver of freeing up energy for export, and as such exports should be allocated the full costs of DSM.[68] This conclusion drove a long confused series of methods to attempt implementation of the Board's directive, centered on whether, as a result of paying for the DSM activities, the export class should also therefore be allocated in some way the DSM kW.h. Multiple versions of cost of service study methods were reviewed, with assertions that each of the versions in some way double-counted energy or loads.

As a result, by PCOSS11, Hydro had reverted to proposing that DSM costs should be allocated to the participating customer class. The Board provided no new guidance on this matter, such that previous 116/08 directives presumably remain the last direction from the PUB – that is, assign the costs of DSM to exports, but do not make any adjustments to kW.h (i.e., customer classes who participate in DSM benefit from the lower volume of sales, rather than using some artificially grossed up sales before DSM to calculate domestic load, and then crediting the energy efficiency savings kW.h to exports).

Consistent with previous evidence provided on behalf of MIPUG, either of these alternatives could be structured to provide a reasonable cost profile for DSM. However, given the complexities that arose in trying to assign DSM costs to exports, it is marginally better to use the approach now proposed by Hydro, that is direct assignment to the participating customer class.

[68] Order 117/06 page 76

It is also worth noting that Christensen Associates, in the 2012 COS review for Hydro, disagreed with the cost assignment of DSM as Ordered in 116/08 noting that:

> We disagree with this cost treatment, because DSM is not driven by export sales[69]. It could be argued that DSM does free up load that can be sold to exports but this is a possible consequence and not the purpose[70] for which the DSM programs were instituted. DSM cost does not vary with export sales but do vary with marketing to domestic customers.[71]

Christensen Associates recommended DSM programs be assigned to the domestic rate class that they end up benefiting (via reduced load and allocations). Hydro's rationale for adopting this approach is in agreement with CA, that DSM is not driven by export sales and the costs should be assigned to the customer classes benefiting from the DSM programming[72], in a manner that there is no cross-subsidy or cost allocation to the export class.

Among other utilities, DSM programs can often be functionalized as generation instead of being directly assigned to the participating classes. Such as approach would not be appropriate for Manitoba Hydro, for two reasons:

1) A central factor underlying the proposed Manitoba Hydro methodology is that Hydro's DSM programs do not reflect any immediate or even closely linked priority associated with power supply. In the case of other utilities, such as Newfoundland Hydro, DSM activities save power in a given year, and result in benefits from avoided oil generation in that year and each subsequent year. As long as the Newfoundland DSM costs less than the price of oil, credible Cost of Service options include allocating the DSM costs to the power production functions. This is fundamentally different than Manitoba. At the present time, Manitoba Hydro has almost no direct immediate cost causal link for its DSM programs to generation costs. The value of DSM energy in Manitoba is at best linked to deferral of future generation (i.e., Conawapa) which is not expected to be in rates until well into the 2030s at the earliest. In the meantime, DSM serves to reduce Hydro's

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[69] Note in response to PUB/MH-I-16b Christensen Associates states that while DSM program evaluation is based on marginal cost primarily based on export prices, the division of DSM costs to customer groups is based upon cost causation, not product value. DSM costs are incurred for specific customer groups to enable customers within each class to become more efficient and benefit from lower energy bills than they would otherwise incur.

[70] In response to MIPUG/MH-I-15g Christensen Associates states it understands the purpose of DSM at MH to be to encourage cost-effective efficiency in the use of electricity by its Domestic customers. DSM programs must pass threshold tests which evaluate benefits for both Domestic participants and nonparticipants. For participants, a major benefit is bill savings arising from reduced consumption. For non-participants, energy reductions arising from DSM programs can be sold as exports, with the net revenues lowering the cost to serve all Domestic customers, as described in e) above. However, these non-participant benefits are a consequence and not a purpose of DSM.

[71] Appendix 5, Christensen Associates (June 8, 2012) Review of COS Methods, pages 26 - 27

[72] PCOSS13, page 13

domestic revenues in a manner that is not recouped from the corresponding sales in currently low-priced export markets, resulting in net costs to domestic ratepayers from most DSM activities.

2) The DSM energy efficiency activities undertaken by Hydro reflect a marketing of substantial benefits that are not related to lower energy consumption, which go well beyond the energy benefits. Not only does the participating customer see a benefit of lower bills (moreso than the saved power is presently worth on export markets), they also see improved home comfort, or lighting quality, or home values from capital improvements (such as windows) or complementary savings on natural gas or water bills. The vast majority of benefit then, from Hydro's current DSM shows up in the customer's own cost and life quality profile, and not in Hydro's near-term generation costs.

Finally, this DSM assignment approach is advised for one significant pragmatic reason - if a program is being run to the benefit of a single class it eliminates the necessity of other classes not participating to have to review or justify the program as it affects electricity costs. Otherwise the economic value of each individual DSM program would be of particular concern to all classes of ratepayers, not just those offered that program. Under Hydro's approach, if a program is run to the benefit of a particular class, but is not economic as a source of added grid supply, the other classes need not pursue as aggressively the weak economics of this program, as its costs will be entirely assigned only to the participating class. This perspective becomes increasingly acute given the unknown objectives of any forthcoming independent DSM entity.

4.2 DSM – CURTAILABLE RATE PROGRAM

Hydro's proposed method change for DSM costs includes the direct assignment of the costs associated with the Curtailable Rate Program (CRP) to the customer classes that use the program, GSL 30-100kV and GSL >100kV Curtailable customers. However, the CRP is not the same as other DSM programs, in that it does not result in energy benefits for the participating customer, but rather reliability inconveniences for that customer[73] to the benefit of every other customers whose power is not curtailed, there is an offsetting credit provided to the Curtailable customers which is charged against the generation function.

As an overall approach, this method is appropriate.

[73] In addition, unlike energy based DSM programs, the Curtailable customer receives no COS credit (i.e., to reduce their peak) in the Cost of Service study, which further underlines that the customer is participating in the program entirely due to the monthly credit provided on their bills, not for any inherent benefits that the program provides beyond this credit (as there are no such inherent benefits).

Issues arise, however, with the specific mathematics of the approach applied by Hydro in PCOSS14-Amended. In that PCOSS, the cost assigned to the GSL 30-100 kV and >100kV curtailable customers totals $8.548 million.[74] This is the total cost of the program in Hydro's revenue requirement, including all amortization and carrying costs on unamortized balances reflecting the 10 year amortization of the program's costs. Inconsistently, however, Hydro applies an offsetting credit of only $5.766 million to these customer classes[75], which is the estimated annual cost of credits provided under the program. The result is that curtailable customers in the PCOSS14-Amended are directly assigned a net $2.782 million cost, as well as allocated a further portion of the program costs for this reliability benefit, for the privilege of foregoing the actual reliability benefit that arises. The result serves to function as a form of claw back of the annual credit, of only $5.766 million on their bills, rescinding approximately 50% of the value that was purported to be provided to these customers.

A simple adjustment to ensure that the credit provided matches the full revenue requirement associated with the program (i.e., $8.548 million), so as to hold these customers whole, is appropriate and necessary to deal with fairness issues arising in PCOSS14-Amended.

[74] From DSM excel file, 'Tables' tab, sum of Curtil 30-100kV Curtail Prgrm Only and Curtail >100kV Curtail Prgm Only.

[75] From PCOSS14-Amended, Schedule E1 page 2, Misc. Rev assigned to E12 Generation – Domestic & Dependable Export.

5.0 POLICY RELATED ITEMS IN THE COST OF SERVICE STUDY

Hydro's Cost of Service study includes two adjustments that do not in any way reflect cost of providing service, but instead reflect Hydro's interpretation of the policy framework for setting rates. These are the Uniform Rate Adjustment (URA) and the Affordable Energy Fund (AEF). Both costs are directly assigned to the export class, despite the fact that neither cost items is in any way caused by the export class or related to providing export service.

In addition, the Cost of Service study includes a special allocation of a category called "Net Export Revenue". This is the amount that Manitoba Hydro references as the "surplus above embedded cost not belonging to any particular class"[76]. Hydro proposes to continue with the previous method that incorporates these net export revenues in the Cost of Service study as an offset to domestic customer costs, based on total allocated costs.

This section addresses the three methods in Hydro's COSS driven by policy:

- Uniform Rate Adjustment
- Affordable Energy Fund
- Net Export Revenue

5.1 UNIFORM RATE ADJUSTMENT

The Manitoba Legislature passed Bill 27 in 2001, amending the Manitoba Hydro Act to enforce equalized or uniform rates for power supplied to a class of customers throughout the province.[77] At the specified date of implementation (November 1, 2001), rates for customers in rural and lower density zones were reduced on a one-time basis to match the rates in Winnipeg. Prior to this time, Hydro rates for distribution level customers were designed based on 3 different "zones" linked to differences in the costs to provide service in the associated zone (e.g., Winnipeg versus rural).

In response to Bill 27, two adjustments were made to Hydro's cost of service study:

1) Hydro stopped recording a breakdown of customers into three zones for the purpose of allocating costs. This simplification is appropriate and reflects that the zonal distinction no longer has relevance for rate setting.

2) Hydro began giving the affected classes (primarily residential) a large "credit" paid for out of export revenues, to compensate for the one time revenue reduction that occurred in 2001.

[76] MIPUG/MH-I-11b
[77] MIPUG/MH-I-11c

At the time Uniform Rates were implemented, the province noted that this approach of levelizing rates through a province was a reasonable approach for grid connected customers: "Uniform rates are common in Canada, offered by utilities such as B.C. Hydro, Hydro-Quebec and Nova Scotia Power"[78]

In Hydro's 2004 GRA, the PUB directed that the legislated 2001 revenue reduction offered to the affected classes should not be a factor driving calculated revenue shortfalls for these classes. At that time the Board directed the impact of uniform rates legislation be applied to the net export revenue, which added positive revenue adjustments to the Residential, GSS, GSM and Street Lighting classes, totaling approximately $14 million.

In PCOSS14-Amended, the Uniform Rate Adjustment has increased to $23.532 million, mainly credited to the residential class, with a small amount to GSS, GSM and Lighting.

Christensen Associates, in their COS review recommends that URA costs should be assigned to the domestic classes which benefit from this adjustment.[79] Hydro agrees with CA's characterization of the cost and causation, acknowledging that the treatment also distorts the true margin from electricity sales.[80] Despite these issues with the adjustment, Hydro is not proposing to change the treatment at this time. Hydro does note, however, that "if as a result of over-assigning embedded cost responsibility to the export class, export revenue is forced to a point that it is insufficient to notionally fund such initiatives, it would be appropriate to seek an alternative cost of service treatment".[81]

It has now been 15 years since the one-time rate adjustment occurred to distribution customers. Rates today are not burdened by revenue shortfalls arising directly from this 2001 directive. Further, as noted by the province, many jurisdictions use a similar policy of levelization of rates for grid connected customers, and none have been identified that incorporate a near permanent subsidy into the COS to compensate the affected classes for this policy.

The difficultly also arises that the adjustment distorts the cost measurements for the affected classes. In this regard it is worth noting that the Uniform Rates legislation is not a "cost" to Hydro. It is a revenue reduction. In order to implement the Uniform Rates adjustment in the Cost of Service study, Hydro is required to artificially increase the recorded revenues from the affected classes, and turn this into a "cost" for the purpose of allocating to the export class.

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[78] Government Press Release "PROVINCE TO TAKE STEPS TO EQUALIZE ELECTRICITY RATES ACROSS MANITOBA" May 28, 2001 http://news.gov.mb.ca/news/index.html?item=25186&posted=2001-05-28

[79] Appendix 5, Christensen Associates (June 8, 2012) Review of COS Methods, page 9 - 10

[80] Appendix 4, Manitoba Hydro's Response to the COS Recommendations of Christensen Associates, page 5

[81] MIPUG/MH-I-11b

If the revenues for the affected classes were not artificially increased, and the shortfall assigned as a cost to the export class, the measured Net Export Revenue would be higher by $23.532 million, as it would no longer be distorted downward by this item.

As a result of the above concerns, this Uniform Rates policy adjustment should not be included in the Cost of Service study methods.

5.2 AFFORDABLE ENERGY FUND

Similar to the Uniform Rate Adjustment, the Affordable Energy Fund was introduced through Provincial Legislation. In 2006 the Provincial Government introduced The Winter Heating Cost Control Act which established the Affordable Energy Fund, requiring Hydro to contribute 5.5% of its fiscal 2006/07 gross export revenues to the AEF. This resulted in a fund of $35 million to be utilized for various energy efficiency initiatives, including, if primarily, assisting low-income electricity and natural gas customers.

Hydro indicated that $19 million of the AEF's $35 million was earmarked for province-wide low-income initiatives, with $8 million for community energy development, $0.25 million to expand the eligibility of Power Smart programs in Manitoba to include residential homes heated with energy other than natural gas or electricity, $0.75 million for rural and northern support and outreach, and $1 million for special projects then-yet to be defined.[82]

Hydro's Annual Report for 2014/15 notes that of the original $35 million, only $6 million remained to be spent as at March 31, 2015.[83]

Manitoba Hydro's position on the Cost of Service treatment of the AEF was set out in response to the Christensen Associates 2012 report[84] where Hydro notes:

> MH agrees with CA's characterization of this cost, i.e., that it benefits certain domestic customer groups and is not correctly assigned or allocated to the Export Class. However, MH does not propose to change the treatment of the AEF within the PCOSS. The AEF is not considered to be a cost related to exports, but to be a policy-related first charge against NER. As provided in the AEF Legislation, the Fund is to support certain energy objectives and not to recover the cost of such programming from the affected customers.
>
> CAs' alternative recommendation is to exclude the expenditure from the PCOSS. If this were to be done, there would have to be a comparable reduction on the revenue side or

[82] Board Order 116/08, page 202 - 203
[83] Manitoba Hydro 2014/15 Annual Report, page 87.
[84] Manitoba Hydro filing Appendix 4.

> increase in net income. This however, would be in contravention to the AEF Legislation. The existing treatment of this expenditure has an equivalent effect while acknowledging that this treatment distorts the true margin from electricity sales.

As the AEF was intended to be a one-time funding from the 2006/07 revenues, it is not apparent why the AEF is included in PCOSS14-Amended in any fashion. A problem appears to be Hydro's decision to account for the AEF in its financial statements in a manner that did not, in fact, charge revenue (and ultimately retained earnings) for the AEF in 2006/07, and the decision not to create a true "fund". Instead AEF has been treated effectively as a pay as you go plan, with costs showing up in each year after 2006/07, including cost associated with deferring and amortizing the cost of the AEF programming.

While the Cost of Service review is not the appropriate time to deal with Hydro's accounting approach, it is appropriate to consider whether there is in fact a cost that should be included in PCOSS14-Amended related to the AEF. Based on the fact this was to be a program that was fully funded from a portion of Hydro's 2006/07 earnings, there does not appear to be any reason to include the AEF as a cost in any PCOSS for years after 2006/07. This is consistent with CA's recommendation. The only issue with this approach appears to be Hydro's practice which seeks to balance each PCOSS to 100.00% Revenue Cost Comparison (RCC) ratio for the system as a whole. This is not common practice, and where revenues are not perfectly matching the identified costs for the year in question (including the forecast Net Income as shown in the respective IFF), the PCOSS should be readily able to report a systemwide RCC that is not equal to 100.00%. If this approach were adopted, there would be no issue incorporating the Christensen Associated recommendation that the AEF should be excluded from the PCOSS, and not charged against any customer class nor against NER for the PCOSS year in question.

In addition, Christensen Associates in its COS review noted that the AEF contains cost related to natural gas efficiency improvements, which have nothing to do directly with electricity sales in either the domestic or the export markets. Christensen Associates recommended that this cost not show up in COS for any rate classes unless it is related to electricity sales.[85] This is an appropriate and reasonable conclusion.

5.3 NET EXPORT REVENUE

The total export revenues projected by Hydro comprise effectively two categories: 1) the portion of revenue that is required to pay a fair share of Hydro's costs based on the export load profile and capital planning assumptions, and 2) an additional amount (positive or negative) that is the residual export

[85] Appendix 5, Christensen Associates (June 8, 2012) Review of COS Methods, pages 9 - 10

revenue forecast to be collected over and above the cost as calculated in (1). This residual amount is termed the Net Export Revenue ("NER").

Overall, there appears to be no dispute that any positive NER is meant to benefit customers – customers take on the risks of all Hydro's activities, including expansion and export market participation, and as such receive an entitlement to benefit from the related export market activity.

The question that has effectively been framed for Cost of Service is 'how should customers benefit from this NER?'. This is an unusual question for a Cost of Service process, in that the NER is not inherently linked to costs but instead residual revenue. Recognizing this issue, CA noted that "There is no good cost basis for the allocation of Net Export Revenues."[86]

Christensen Associates has provided a series of options for consideration, many of which do not fit the Manitoba Hydro system facts (e.g., the response to PUB/MH-I-18a appropriately rules out the "unused capacity" concept). However, one of CA's options fits well with previous testimony provided on behalf of MIPUG, as follows:

> Do not allocate NER back to domestic classes directly. Instead, place NER funds in a separate account classified as retained earnings for use in future construction or debt buy-back. This approach has the virtue of insulating retail rates from swings in NER over time, as well as lowering the funding cost of future capital expenditure.[87]

In the 2006 Cost of Service Review, the Pre-Filed Testimony of Bowman and McLaren had a similar recommendation:

> **As a preferred approach, apply a portion of export revenue to pay down debt via a "regulated reserve fund" against future droughts.** The most attractive alternative for use of export revenues that are in excess of amounts that can be reasonably addressed by principled COSS approaches likely is to allocate these amounts towards a regulated reserve fund for future use to stabilize rates in the event of a drought. This approach would simultaneously allow for repayment of portions of Hydro's debt (which is currently at unprecedented levels, and scheduled to grow, particularly with new northern generation and transmission proposed[88]), and development of reserves to address future drought risks. Depending on the approach noted in the section above, it is conceivable that amounts in the

[86] Appendix 2, Christensen Associates Supplemental Report (August 10, 2015), page 1

[87] Appendix 5, Christensen Associates (June 8, 2012) Review on COS methods, page 11

[88] Refer to IFF MH05-1 page 33 which shows the sum of forecast long-term debt plus current and other liabilities to be $8.760 billion in 2005/06 growing to $9.798 billion by 2009/10 and $11.598 billion by 2015/16.

> range of $50 million (to perhaps as high as $100 million) in 2006 might suitably be considered for this purpose. Key to this approach is development of a mechanism to ensure that the amounts are held in a regulated reserve under the direction of the PUB, rather than as Hydro's shareholder equity which is subject to all sorts of potential constraints or pressures. This treatment may be appealing particularly in light of the Board's continued concern with respect to Hydro's overall level of debt[89], lack of suitable reserves to address drought risk[90] and the fact that such a treatment would have benefits for all ratepayers by reducing Manitoba Hydro's interest expense requirements in future years.[91]

The above concepts share a significant common core approach – specifically, once a NER has been identified, do not try to allocate it back via a Cost of Service study, as it is no longer analytically linked to costs. At the same time, both approaches recognize that the NER (if positive) is a source of funds that is intended to provide benefits to ratepayers. Both approaches are premised on a fundamental concept that the cost of service study should be principled and defensible. Also, both are premised on the idea that a preferred use of NER may be for purposes other than simply lowering the level of rates in any immediate period. In short, ratepayer's economic interests in the rates they pay goes beyond just the current rates, the ratepayer interest also links to achieving more stable rates via a principled method of building up reserves under the direction of the PUB, that can cover future costs which may drive unstable rates (in the case of Bowman and McLaren, drought, and in the case of Christensen Associates, capital expenditures).

One final issue with the NER concepts above is that Manitoba Hydro has demonstrated an inability to consider any approach where cost or revenue items are "not included" in the PCOSS. Specifically, in PUB/MH-I-18d, Hydro notes: "regardless of the method chosen to allocate costs against exports, or the method chosen to allocate net export revenue credits against the costs allocated among the domestic classes of service, the same total revenue must be obtained from domestic classes collectively". Hydro's view is not consistent with the typical use of Cost of Service studies. Under Hydro's interpretation, the Cost of Service study must balance revenues to costs 100.00% in the systemwide total at all times. However, it is entirely reasonable that the NER not be included in the PCOSS, and if NER would otherwise be positive, the RCC systemwide would be slightly below 100.00%. This simply indicates that before any

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[89] The Board most recently expressed this concern in Order 34/05 with respect to Manitoba Hydro's conditional rate increase where the Board stated at page 17 "Hydro's financial results and position have implications for the overall position of the Province, being Manitoba's largest Crown Corporation and having a debt level that represents more than 50% of the Province's outstanding debt."

[90] In Order 143/04 at page 85, the Board stated "This drought also highlighted the increased risks faced by MH in the export market, and the resulting need for MH to build and maintain adequate reserves in advance of further significant investments in generating and transmission facilities."

[91] Re-filed in this proceeding as MIPUG-4, page 17

NER balance is used in the manner described by CA or Bowman and McLaren, the overall customer rates would first need to somewhat increase, such that each class is closer to 100% RCC and the systemwide RCC is at or near 100.00%. This rate shift can occur gradually over time and once completed, the NER can start to be targeted to the priority use.

Transitioning to this NER approach would require considerably further work on implementation details, beyond just adoption in the PCOSS methods. Among other considerations, were this approach to be adopted, the PCOSS methods would have to ensure that the costs allocated to the export class fully and completely cover the range of costs driven by the export class. Under the methods outlined above in this submission (e.g., with fixed costs allocated to opportunity exports) this criteria should be fulfilled. Under the export class cost allocation methods proposed by Hydro in PCOSS14-Amended, the export class cost allocation is too low, and the NER to be "removed" from the PCOSS would be significantly overstated. This NER approach should not be considered until the under-assignment of costs to the export class, as proposed by Hydro, is corrected.

As an approximate measure of the NER under the proposals above, MIPUG MFR-7 shows an NER of negative $17.804 million (once implementing the corrected single export class), but this would improve by approximately $36.3 million for the URA and AEF adjustments noted above[92], for an approximate positive NER of $18.5 million/year.[93]

[92] PCOSS14-Amended, page 4 (Policy Related Charges AEF & URA)

[93] The remaining adjustments recommended in this testimony, such as allocating Brandon coal only to domestic, would be expected to have a smaller impact on NER.

ATTACHMENT A – COST OF SERVICE RESULTS SINCE 1992

In each of Hydro's rate reviews, a Cost of Service study has been produced which calculates the revenue cost coverage (RCC) ratio for each customer class and subclass – essentially the measure of the degree to which the rates charged to a customer class fairly reflect the net costs that the customer class imposes on Hydro's system. A RCC ratio of 1.00 or 100% illustrates rates that are equal to the calculated costs. A RCC ratio greater than 1.0 indicates that the revenues from a class are above the calculated costs to serve that class. In this case, costs are defined to include all revenues required by Hydro, including required contributions to reserves.

The PUB and Hydro have each recognized that RCCs should not vary from 100% to any marked degree (e.g., within a 'Zone of Reasonableness' of 95% to 105%) and that there is no basis to maintain a customer class RCC at above or below 100% on a consistent basis. The PUB used a Zone of Reasonableness (ZOR) prior to 1996 that equalled 90% to 110%, and revised this range to 95% to 105% in Order 51/96.[94]

In each year, the RCC ratio can change for a number of reasons:

- **Changes in the relative level of rates and/or revenue component:** This can include rate increases or decreases. In Order 7/03 the Board ordered rate decreases for certain classes in recognition of the fact that these classes had remained outside of the zone of reasonableness for long periods of time. There has not been customer specific rate changes (except for in the case of the lighting class) since. Across-the-board rate increases will also impact RCC ratios and have occurred each year for the past decade[95] with Hydro forecasting successive rate increases for at least the next decade.
- **Changes in the utility costs and the variables that are used to allocate costs:** This includes such variables as the system peak and total energy sales that are used to assign certain types of costs in the Cost of Service study, such as loads and load shape.
- **Changes in the Cost of Service Methodology:** Changes to Manitoba Hydro's COSS have occurred periodically throughout the years shown below. These changes are typically incorporated into Hydro's PCOSS before being reviewed and approved by the PUB.

[94] In Decision 51/96 the Board directed Hydro to undertake a study prior to the next GRA to address alternatives for solving the persistent problem of some rate sub-classes (specifically Residential Zone 3 and General Service Large >100kv) being persistently outside the Zone of Reasonableness. The Board also indicated that this study should assume a revised ZOR target of 95%-105%. See page 41 of Board Order 51/96

[95] Consistent rate increases have occurred in each year since Order 20/07 approving a rate increase in the 2006/07 fiscal year (finalized in Order 90/08).

Table and Figure A-1 review the RCC ratios from 1991/92 to 2010/11 for the respective methodologies as used at each respective time period. This covers the period prior to the Christensen reports and Hydro's current PCOSS proposals. Where multiple methodologies are available for a given PCOSS, the table shown the PCOSS most consistent with the then previously approved PUB methodology.

The table shows a consistent material variance in RCC ratios from 100% for many customer classes during this period. Industrial customers (class GS Large >100kV in particular) have historically had a RCC well above the zone of reasonableness defined by the Board.

Table A-1: Revenue Cost Coverage Ratios 1991/92 to 2010/11

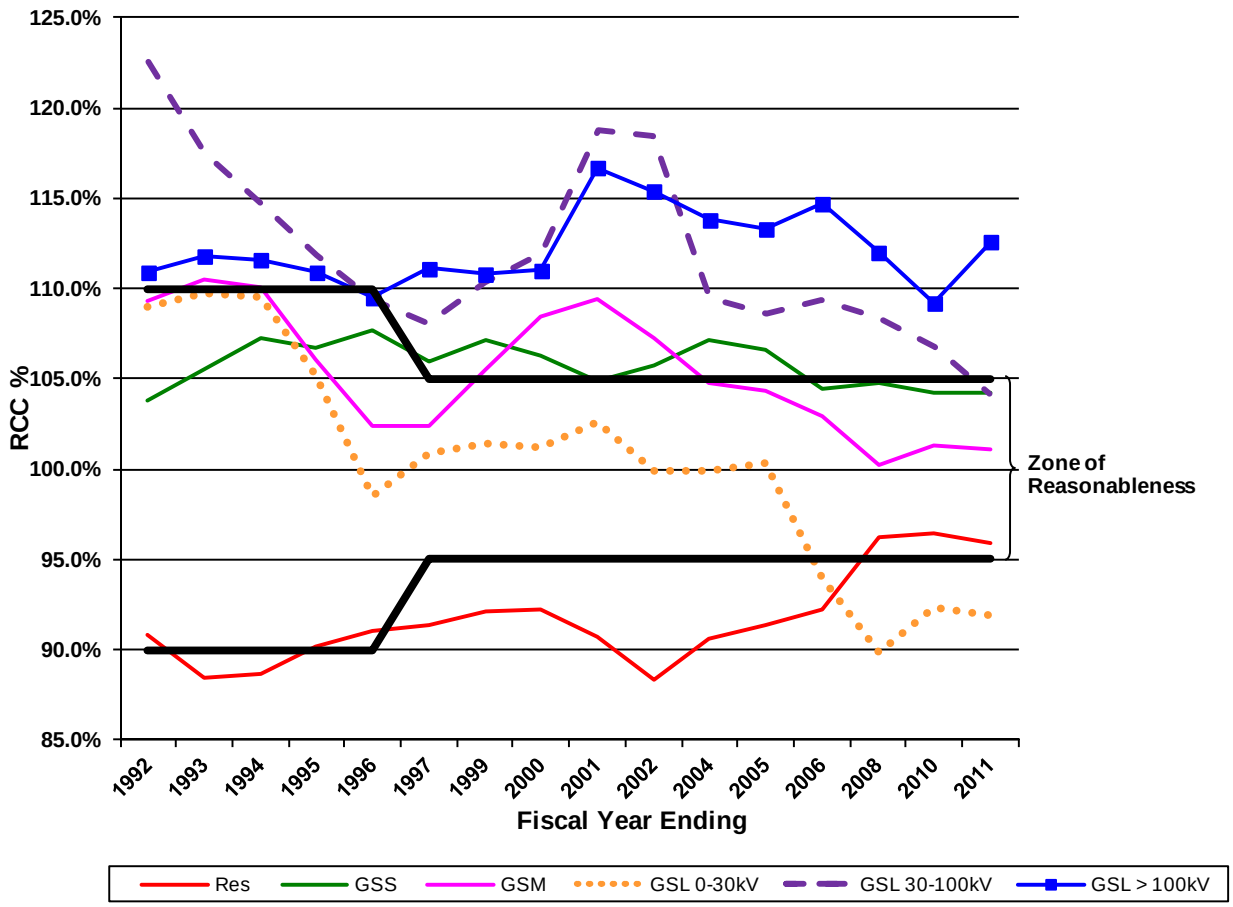
(With PUB Approved Methods)[96]

	91	92	93	94	95	96	97	99	00	01	02	04	05	06	08	10	11
Res	86.5%	90.8%	88.5%	88.7%	90.2%	91.1%	91.4%	92.1%	92.2%	90.7%	88.4%	90.6%	91.4%	92.2%	96.2%	96.4%	95.9%
GSS (D & ND)	106.9%	103.8%	105.5%	107.3%	106.7%	107.7%	106.0%	107.2%	106.3%	104.9%	105.8%	107.2%	106.6%	104.4%	104.8%	104.2%	104.3%
GSM	114.7%	109.3%	110.5%	110.1%	106.1%	102.4%	102.4%	105.5%	108.4%	109.4%	107.3%	104.8%	104.3%	102.9%	100.2%	101.3%	101.1%
GSL 0 -30kv	112.7%	109.0%	109.7%	109.5%	105.2%	98.5%	100.9%	101.4%	101.2%	102.6%	99.9%	99.9%	100.3%	94.0%	89.9%	92.3%	91.9%
GSL30-100kv	117.1%	122.5%	117.5%	114.8%	111.8%	109.4%	108.1%	110.3%	112.0%	118.8%	118.5%	109.5%	108.6%	109.4%	108.4%	106.8%	104.2%
GSL>100kv	115.6%	110.9%	111.8%	111.6%	110.9%	109.5%	111.1%	110.8%	111.0%	116.7%	115.4%	113.8%	113.3%	114.7%	112.0%	109.2%	112.6%
Lighting	127.8%	118.7%	119.0%	117.0%	119.6%	112.5%	108.8%	93.4%	95.3%	92.0%	97.6%	108.9%	109.8%	105.2%	102.4%	100%	105.2%
Diesel	83.6%	97.3%	99.5%	95.3%	90.3%	95.4%	92.5%								46.8%	47.1%	42.6%

This information is presented graphically in Figure B-1, which also indicates the ZOR as determined by the Board for the respective year.

[96] Data for 1991/92-1996/97 from MIPUG/MH/CR-2(b) from the 1996/97 GRA. 1998/99-2001/02 data from MIPUG/MH I-30 (a) from 2001/02 GRA. 2001/02 data represents the previous PCOSS methodology as stated in MIPUG/MH I-30 (a) from 2001/02 GRA. No PCOSS was available for 1997/98 or 2002/03. 2003/04 data from PUB/MH I-28(c) from 2003/04 GRA. 2004/05 data from MIPUB/MH I-21(f) from 2003/04 GRA. All other data available in this proceeding: 2005/06 data from PCOSS06 based on 117/06 PUB Approved Directive (PUB-MFR-7 in this proceeding), PUB. 2007/08 data 2008_116_08 Data from Order 116/08 Directive 19 Revisions to PCOSS08 (PUB-MFR-9 in this proceeding), 2009/10 from PCOSS10, 2010/11 from PCOSS11,

Figure A-1: Revenue Cost Coverage Ratios 1991/92 to 2010/11 (PUB Approved Methods)[97]



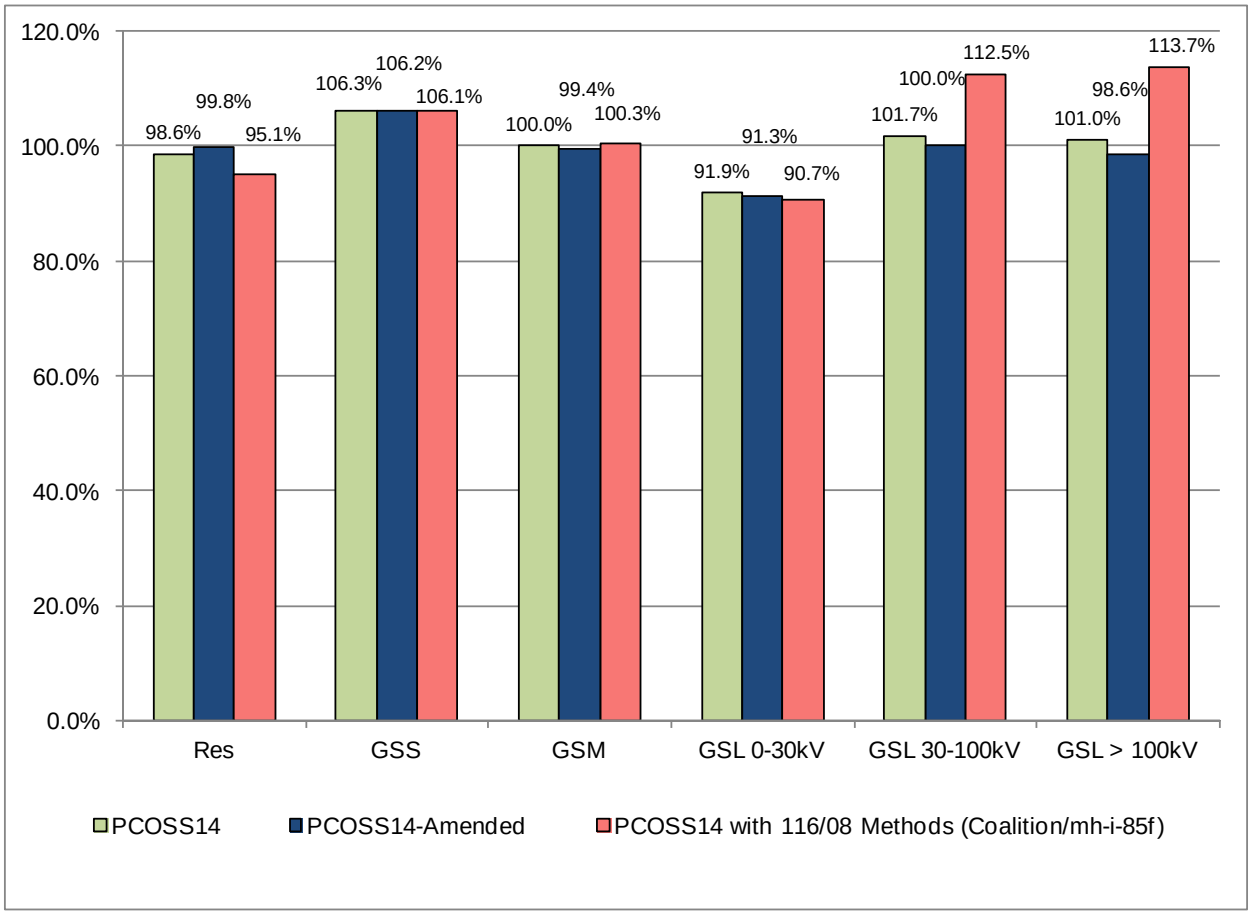
A review of Table A-1 and Figure A-1 indicates that since rate increases have been across-the-board since 2004, revenue solutions to the RCCs which persistently deviate from 100% have not been applied.

For PCOSS14 methods, there are large differences in RCC ratios as shown in Figure A-2 between Hydro's method from PCOSS14, Hydro's current proposed method in PCOSS14-Amended and the method that closely parallels that last approved by the PUB in 2008 from COALITION/MH-I-85f (with 116/08 methods

[97] Data for 1991/92-1996/97 from MIPUG/MH/CR-2(b) from the 1996/97 GRA. 1998/99-2001/02 data from MIPUG/MH I-30 (a) from 2001/02 GRA. 2001/02 data represents the previous PCOSS methodology as stated in MIPUG/MH I-30 (a) from 2001/02 GRA. No PCOSS was available for 1997/98 or 2002/03. 2003/04 data from PUB/MH I-28(c) from 2003/04 GRA. 2004/05 data from MIPUB/MH I-21(f) from 2003/04 GRA. All other data available in this proceeding: 2005/06 data from PCOSS06 based on 117/06 PUB Approved Directive (PUB-MFR-7 in this proceeding), PUB. 2007/08 data 2008_116_08 Data from Order 116/08 Directive 19 Revisions to PCOSS08 (PUB-MFR-9 in this proceeding), 2009/10 from PCOSS10, 2010/11 from PCOSS11,

and the DSM savings allocation issue fixed). Each of these methods are based on the same PCOSS14 input data.

Figure A-2: RCC Ratio Comparison for PCOSS14 – Hydro Recommended (Amended), PCOSS13 Methods & PUB Approved[98]



Another effective tool to analyze the impacts of method changes across PCOSS methodologies is to look at the unit cost on a customer class basis (before net export allocation to understand the underlying cost and revenue changes and what is driving them). On a normal basis, the units costs measured to serve each class should be relatively stable from year-to-year. Hydro's results, and the significant impact of methodology changes starting with PCOSS13, is shown in Table A-2 below.

[98] From Schedule B1 in each respective PCOSS with 'PUB Approved' as per Coalition/MH-I-85 f & g

Table A-2: Comparison of PCOSS Unit Cost per Customer Class (before Net Export Revenue Allocation)[99]

	PCOSS06 - Recommended			PCOSS06 - 117/06 Directives			PCOSS08 - 117/06 Directives			PCOSS08 - 116/08 Directives			PCOSS10			PCOSS11		
	Energy ¢/kWh	Demand $/kVa	Customer $/Mth	Energy ¢/kWh	Demand $/kVa	Customer $/Mth	Energy ¢/kWh	Demand $/kVa	Customer $/Mth	Energy ¢/kWh	Demand $/kVa	Customer $/Mth	Energy ¢/kWh	Demand $/kVa	Customer $/Mth	Energy ¢/kWh	Demand $/kVa	Customer $/Mth
Residential	6.98		20.80	6.48		20.80	6.14		21.61	5.44		20.75	6.38		22.59	6.11		22.35
GSS - ND	6.56		35.30	5.94		35.30	6.00		36.10	5.56		35.04	6.24		37.64	5.98		38.67
GSS - D	5.25	8.17	63.18	4.64	8.11	63.18	4.70	8.07	59.17	4.20	7.74	57.20	4.88	8.58	57.04	4.73	8.68	55.52
GSM	3.67	8.32	261.83	3.11	8.30	261.83	3.05	8.55	263.12	2.64	8.34	258.87	3.25	9.77	274.56	3.35	8.73	293.67
GSL 0-30kV	3.68	9.40		3.06	9.29		3.01	9.73		2.56	9.37		3.19	9.58		3.00	9.33	
GSL 30-100kV	3.35	5.14		2.86	5.04		2.84	5.33		2.33	5.21		2.86	5.30		2.69	6.04	
GSL over 100kV	3.32	3.20		2.82	2.75		2.80	3.19		2.32	3.67		2.83	3.67		2.65	3.63	
Lighting	5.87		7.82	5.16		7.82	5.35		7.72	6.07		7.38	5.13		8.33	5.12		7.75
SEP	7.35		834.11	7.35		834.11	5.88		1,062.24	5.88		1,051.21	5.16		1,187.66	4.90		946.48
Export										5.54			5.32			4.74		

	PCOSS13 - b4 Method Changes			PCOSS13 - w Method Changes			PCOSS14 - COALITION/MH-I-85f (before NER)			PCOSS14			PCOSS14 - Amended		
	Energy ¢/kWh	Demand $/kVa	Customer $/Mth	Energy ¢/kWh	Demand $/kVa	Customer $/Mth	Energy ¢/kWh	Demand $/kVa	Customer $/Mth	Energy ¢/kWh	Demand $/kVa	Customer $/Mth	Energy ¢/kWh	Demand $/kVa	Customer $/Mth
Residential	6.02		20.80	6.42		20.80	5.72		21.87	6.52		22.06	6.76		22.06
GSS - ND	5.90		37.57	6.30		37.57	5.53		39.54	6.39		39.78	6.65		39.78
GSS - D	4.75	7.23	57.54	5.09	7.58	57.54	4.37	7.31	57.81	5.18	7.48	58.18	5.55	6.63	58.18
GSM	3.52	7.74	308.29	3.82	8.14	308.29	3.19	7.91	321.03	3.92	8.13	322.02	4.42	7.15	322.01
GSL 0-30kV	3.19	8.06		3.47	8.02		2.84	8.53		3.59	8.38		4.12	7.33	
GSL 30-100kV	2.91	5.72		3.17	6.11		2.52	4.51		3.26	5.15		3.72	4.25	
GSL over 100kV	2.91	3.54		3.17	3.99		2.53	3.20		3.25	3.89		3.69	2.79	
Lighting	2.80		8.40	5.09		8.40	5.70		8.87	5.19		8.95	5.32		8.95
SEP	4.80		918.91	2.80		918.91	0.00		933.74	2.42		935.95	2.42		935.95
Export	4.87			3.79			5.40			3.45			2.82		

For Hydro's proposed methods in PCOSS14-Amended, there are very significant impacts on unit costs stemming from methodology changes in direct assignment, functionalization, classification and allocation.

The Figures and Tables below compare Hydro's recommended approach and the unit cost per rate class on a functionalized basis compared with the methodology last approved by the PUB in Order 116/08 as provided in COALITION/MH-I-85f[100] (with all costs reported as solely energy costs, to permit direct comparison).

[99] PCOSS06 Recommended Method to PCOSS14-Amended from MIPUG/MH-I-6a. PCOSS14-COALITION/MH-I-85f represents the PCOSS14 version based on Board approved methods in 116/08 with US Interconnection classified as demand and allocated using 2CP, Dorsey converter stations functionalized as transmission and weighted energy allocator that does not incorporate explicit capacity component and calculated from Hydro excel model provided titled 'COALITION-MH-85g-att1.xlsx'.

[100] This is the PCOSS14 scenario using 116/08 methods, which fixes the DSM savings allocation issue from that timeframe.

Figure A-3: Customer Class Costs and Revenues per PCOSS14-Amended

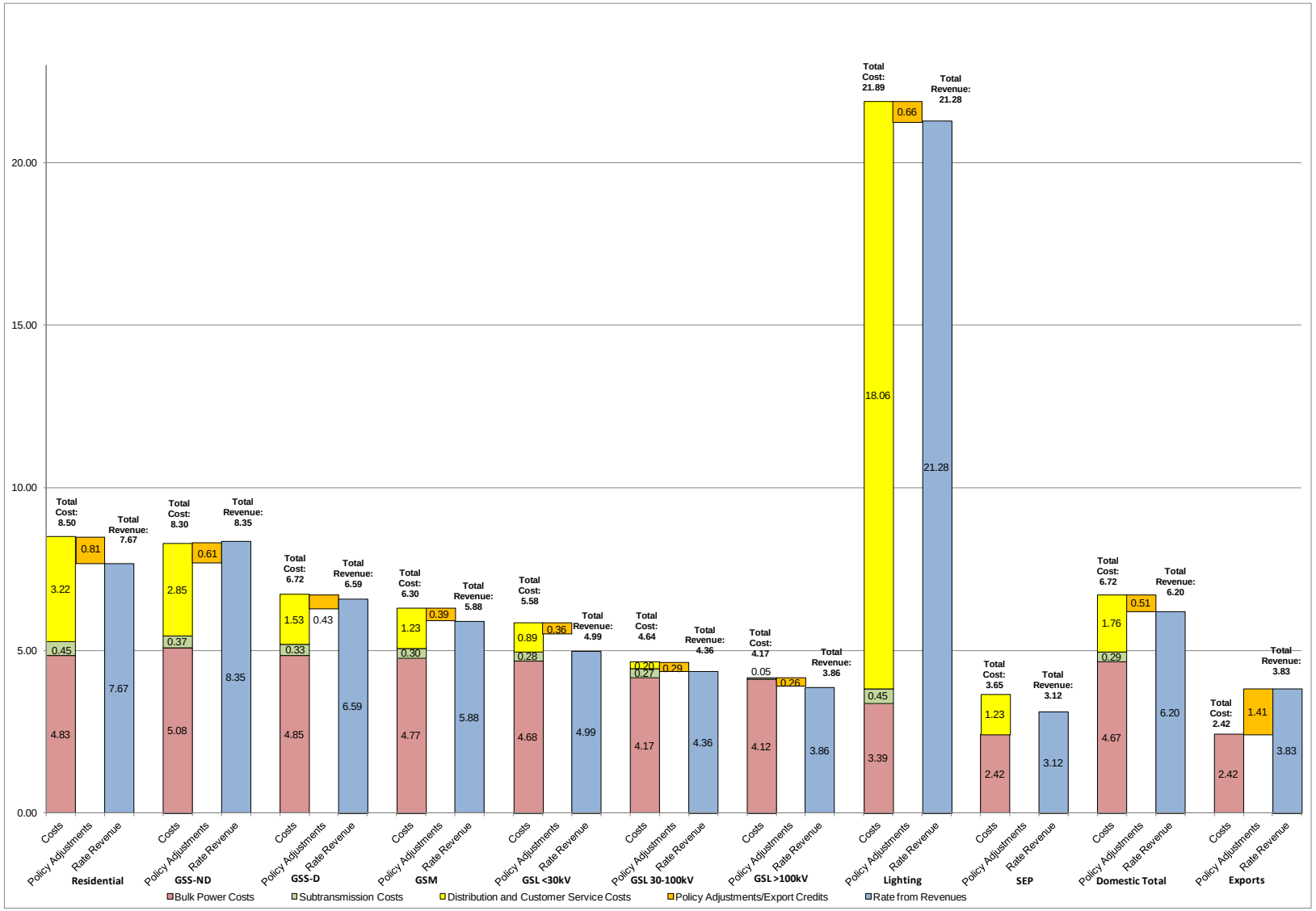


Table A-3: Customer Class Costs and Revenues per PCOSS14-Amended[101]

	Residential		GSS-ND		GSS-D		GSM		GSL<30kV		GSL 30-100kV		GSL>100kV	
	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)
Costs														
1 Bulk Power Costs	$357.86	4.83	$81.08	5.08	$99.86	4.85	$151.56	4.77	$79.76	4.68	$55.33	4.17	$202.09	4.12
2 plus: Subtransmission-related	$33.09	0.45	$5.97	0.37	$6.88	0.33	$9.51	0.30	$4.76	0.28	$3.63	0.27	$0.00	0.00
3 plus: Distrib. and Cust. Serv.	$238.26	3.22	$45.41	2.85	$31.47	1.53	$39.07	1.23	$15.19	0.89	$2.65	0.20	$2.45	0.05
4 Total Costs	**$629.22**	**8.50**	**$132.46**	**8.30**	**$138.21**	**6.72**	**$200.14**	**6.30**	**$99.70**	**5.86**	**$61.61**	**4.64**	**$204.54**	**4.17**
Rates														
5 Total PCOSS Sales Revenue	**$567.60**	**7.67**	**$133.25**	**8.35**	**$135.65**	**6.59**	**$186.76**	**5.88**	**$84.96**	**4.99**	**$57.81**	**4.36**	**$189.26**	**3.86**
Surplus/Shortfall before Net Export Credits														
6 Rates compared to costs (5-4)	**($61.62)**	**-0.83**	**$0.79**	**0.05**	**($2.56)**	**-0.12**	**($13.38)**	**-0.42**	**($14.75)**	**-0.87**	**($3.81)**	**-0.29**	**($15.28)**	**-0.31**
7 Revenue:Cost Ratio (Net of Policy Adjustments and Export Credits) (line 5/ line 4)	**90.21%**		**100.60%**		**98.15%**		**93.31%**		**85.21%**		**93.82%**		**92.53%**	
Policy Adjustments														
8 Uniform Rate Credit	$21.03	0.28	$1.78	0.11	$0.43	0.02	$0.04	0.00	$0.00	0.00	$0.00	0.00	$0.00	0.00
9 Affordable Energy Fund Expenditures	$0.00	0.00	$0.00	0.00	$0.00	0.00	$0.00	0.00	$0.00	0.00	$0.00	0.00	$0.00	0.00
10 Net Export Revenue Allocation	$39.18	0.53	$8.02	0.50	$8.35	0.41	$12.19	0.38	$6.06	0.36	$3.81	0.29	$12.51	0.26
11 Surplus/(Shortfall) after net export revenue credits (6+8+9+10)	**($1.41)**	**-0.02**	**$10.59**	**0.66**	**$6.23**	**0.30**	**($1.15)**	**-0.04**	**($8.69)**	**-0.51**	**$0.00**	**0.00**	**($2.77)**	**-0.06**
12 Total Class Metered Energy (GW.h)	7,404		1,596		2,057		3,175		1,702		1,327		4,904	

	Lighting		SEP		Diesel		Domestic Total		Exports	
	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)
Costs										
1 Bulk Power Costs	$3.40	3.39	$0.64	2.42	$9.36	68.06	$1,040.93	4.67	$217.74	2.42
2 plus: Subtransmission-related	$0.45	0.45	$0.00	0.00	$0.00	0.00	$64.30	0.29	$0.00	0.00
3 plus: Distrib. and Cust. Serv.	$18.14	18.06	$0.33	1.23	$0.59	4.27	$393.56	1.76	$0.00	0.00
4 Total Costs	**22.00**	**21.89**	**0.97**	**3.65**	**9.95**	**72.33**	**1,498.79**	**6.72**	**217.74**	**2.42**
Rates										
5 Total PCOSS Sales Revenue	**$21.39**	**21.28**	**$0.83**	**3.12**	**$6.61**	**48.07**	**$1,384.10**	**6.20**	**$345.23**	**3.83**
Surplus/Shortfall before Net Export Credits										
6 Rates compared to costs (5-4)	**($0.61)**	**-0.61**	**($0.14)**	**-0.53**	**($3.34)**	**-24.26**	**($114.69)**	**-0.51**	**$127.50**	**1.41**
7 Revenue:Cost Ratio (Net of Policy Adjustments and Export Credits) (line 5/ line 4)	**97.23%**		**85.49%**		**66.46%**		**92.35%**		**158.56%**	
Policy Adjustments										
8 Uniform Rate Credit	$0.24	0.24	$0.00	0.00	$0.00	0.00	$23.53	0.11	($23.53)	-0.26
9 Affordable Energy Fund Expenditures	$0.00	0.00	$0.00	0.00	$0.00	0.00	$0.00	0.00	($12.80)	-0.14
10 Net Export Revenue Allocation	$0.42	0.42	$0.00	0.00	$0.63	4.55	$91.16	0.41	($91.16)	-1.01
11 Surplus/(Shortfall) after net export revenue credits (6+8+9+10)	**$0.05**	**0.05**	**($0.14)**	**-0.53**	**($2.71)**	**-19.70**	**$0.00**	**0.00**	**$0.00**	**0.00**
12 Total Class Metered Energy (GW.h)	100		27		14		22,307		9,013	

[101] Bulk Power Costs equal to total Generation and Transmission Costs (allocated and direct-assigned) prior to net export revenue allocation, total Subtransmission related costs and total distribution and customer service costs (allocated and direct-assigned) prior to net export revenue allocation, uniform rate credit allocations from Schedule C13, Net Export Revenue from Schedule B1. Total Class Metered Energy from Schedule B2.

Figure A-4: Customer Class Costs and Revenues per PCOSS14 with Order 116/08 Methods (from COALITION/MH I-85f & g)

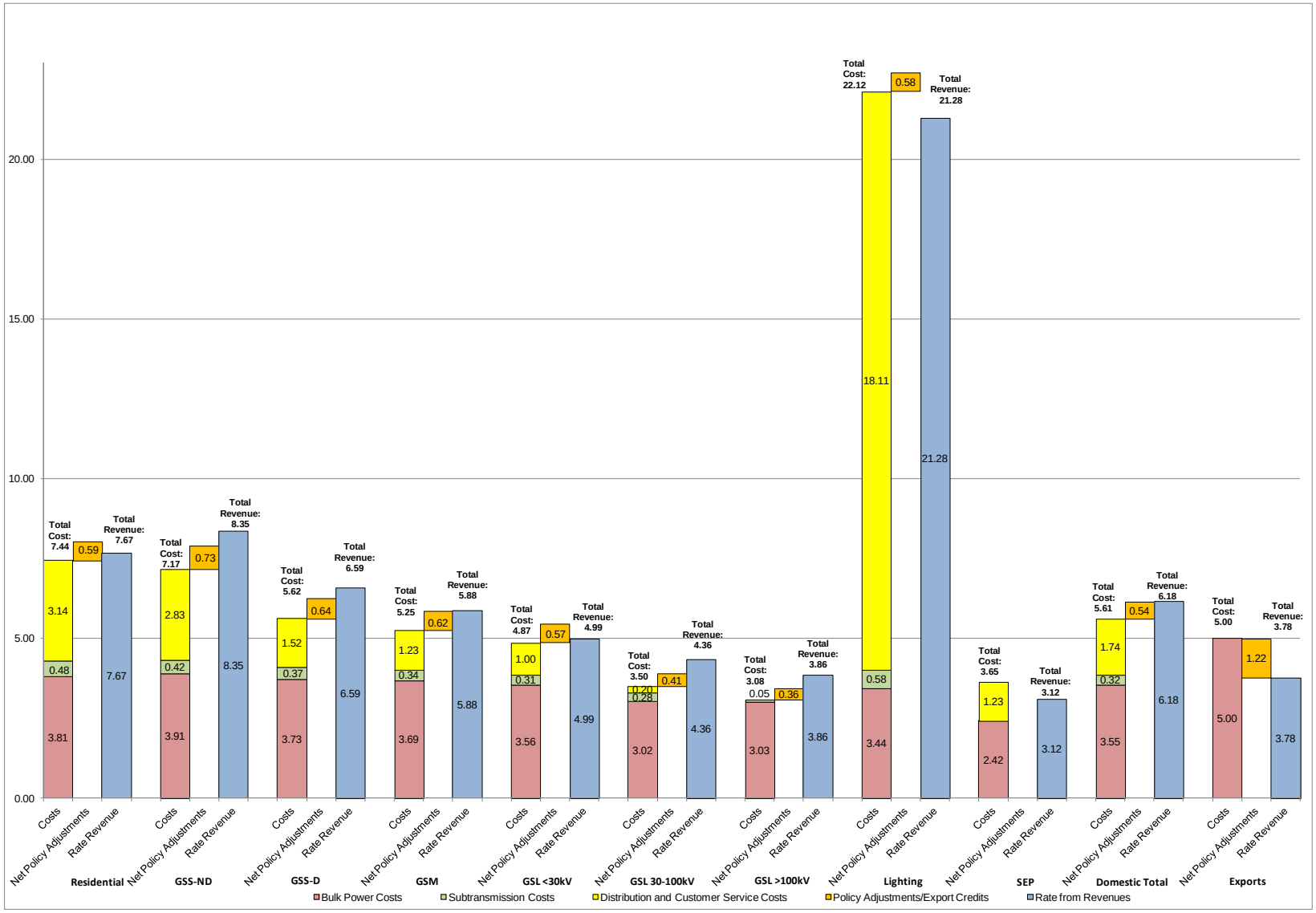


Table A-4: Customer Class Costs and Revenues per PCOSS14 with Order 116/08 Methods (from COALITION/MH I-85 f & g)

	Residential		GSS-ND		GSS-D		GSM		GSL<30kV		GSL 30-100kV		GSL>100kV	
	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)
Costs														
1 Bulk Power Costs	$282.47	3.81	$62.46	3.91	$76.70	3.73	$117.13	3.69	$60.57	3.56	$40.11	3.02	$148.48	3.03
2 plus: Subtransmission-related	$35.86	0.48	$6.72	0.42	$7.71	0.37	$10.70	0.34	$5.31	0.31	$3.75	0.28	$0.00	0.00
3 plus: Distrib. and Cust. Serv.	$232.79	3.14	$45.20	2.83	$31.23	1.52	$38.94	1.23	$17.05	1.00	$2.65	0.20	$2.45	0.05
4 Total Costs	**$551.12**	**7.44**	**$114.38**	**7.17**	**$115.63**	**5.62**	**$166.78**	**5.25**	**$82.92**	**4.87**	**$46.51**	**3.50**	**$150.93**	**3.08**
Rates														
5 Total PCOSS Sales Revenue	**$567.60**	**7.67**	**$133.25**	**8.35**	**$135.65**	**6.59**	**$186.76**	**5.88**	**$84.96**	**4.99**	**$57.81**	**4.36**	**$189.26**	**3.86**
Surplus/Shortfall before Net Export Credits														
6 Rates compared to costs (5-4)	**$16.48**	**0.22**	**$18.87**	**1.18**	**$20.01**	**0.97**	**$19.98**	**0.63**	**$2.03**	**0.12**	**$11.30**	**0.85**	**$38.33**	**0.78**
7 Revenue:Cost Ratio (Net of Policy Adjustments and Export Credits) (line 5/ line 4)	**102.99%**		**116.50%**		**117.31%**		**111.98%**		**102.45%**		**124.28%**		**125.40%**	
Policy Adjustments														
8 Uniform Rate Credit	$21.03	0.28	$1.78	0.11	$0.43	0.02	$0.04	0.00	$0.00	0.00	$0.00	0.00	$0.00	0.00
9 Affordable Energy Fund Expenditures	$0.00	0.00	$0.00	0.00	$0.00	0.00	$0.00	0.00	$0.00	0.00	$0.00	0.00	$0.00	0.00
10 Net Export Revenue Allocation	($64.73)	-0.87	($13.43)	-0.84	($13.58)	-0.66	($19.59)	-0.62	($9.74)	-0.57	($5.46)	-0.41	($17.73)	-0.36
11 Surplus/(Shortfall) after net export revenue credits (6+8+9+10)	**($27.22)**	**-0.37**	**$7.22**	**0.45**	**$6.87**	**0.33**	**$0.43**	**0.01**	**($7.71)**	**-0.45**	**$5.83**	**0.44**	**$20.60**	**0.42**
12 Total Class Metered Energy (GW.h)	7,404		1,596		2,057		3,175		1,702		1,327		4,904	

	Lighting		SEP		Diesel		Domestic Total		Exports	
	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh)	($ M)	(¢/kWh	($ M)	(¢/kWh)
Costs										
1 Bulk Power Costs	$3.46	3.44	$0.64	2.42	$9.32	67.78	$792.01	3.55	$450.39	5.00
2 plus: Subtransmission-related	$0.58	0.58	$0.00	0.00	$0.00	0.00	$70.63	0.32	$0.00	0.00
3 plus: Distrib. and Cust. Serv.	$18.19	18.11	$0.32	1.23	$0.59	4.25	$388.81	1.74	$0.00	0.00
4 Total Costs	**22.23**	**22.12**	**0.97**	**3.65**	**9.91**	**72.04**	**1,251.46**	**5.61**	**450.39**	**5.00**
Rates										
5 Total PCOSS Sales Revenue	**$21.39**	**21.28**	**$0.83**	**3.12**	**$6.61**	**48.07**	**$1,377.49**	**6.18**	**$340.45**	**3.78**
Surplus/Shortfall before Net Export Credits										
6 Rates compared to costs (5-4)	**($0.84)**	**-0.84**	**($0.14)**	**-0.53**	**($3.30)**	**-23.96**	**$126.03**	**0.56**	**($109.93)**	**-1.22**
7 Revenue:Cost Ratio (Net of Policy Adjustments and Export Credits) (line 5/ line 4)	**96.21%**		**85.47%**		**66.73%**		**110.07%**		**75.59%**	
Policy Adjustments										
8 Uniform Rate Credit	$0.24	0.24	$0.00	0.00	$0.00	0.00	$23.53	0.11	($23.53)	-0.26
9 Affordable Energy Fund Expenditures	$0.00	0.00	$0.00	0.00	$0.00	0.00	$0.00	0.00	($12.80)	-0.14
10 Net Export Revenue Allocation	($0.83)	-0.82	$0.00	0.00	($1.16)	-8.46	($145.10)	-0.65	$146.26	1.62
11 Surplus/(Shortfall) after net export revenue credits (6+8+9+10)	**($1.43)**	**-1.42**	**($0.14)**	**-0.53**	**($4.46)**	**-32.43**	**$4.46**	**0.02**	**($0.00)**	**-0.00**
12 Total Class Metered Energy (GW.h)	100		27		14		22,307		9,013	

ATTACHMENT B – HISTORY OF EXPORT CLASS

The export class was debated as part of the 2002 Status Update proceeding, and the need for a class was recognized in Board Order 7/03.[102] The Board indicated that absent an export class, the costs to serve exports were not properly being tracked, and the "Net Export Revenue" calculated by Hydro was excessive. Specifically, "In the Board's view, many direct and indirect costs related to export power sales are currently not included in Hydro's calculation of net export revenues."[103] The Board also specifically cited their report from 1998, as follows:

> "The Board recommends that revenues and costs related to export sales should be segregated in Hydro's accounting records. Costs include direct costs as well as indirect or allocated costs. The purpose of this segregation is to ensure that the Manitoba ratepayer is not subsidizing export sales.
>
> A possible method would be to treat export sales as a separate customer class in the Cost of Service Study. The result would not be used in designing rates for export sales because of the fact that such sales are open market negotiated sales. The only relevance to the resulting export class revenue/cost ratio would be to ensure that Manitoba customers are not allocated costs related to export."[104]

This was not immediately implemented by Hydro, as Hydro studied the Board's directive.

During the 2004 rate application, Hydro filed a report by NERA titled Classification and Allocation Methods for Generation and Transmission in Cost of Service Studies, which supported the creation of an export class, allocating costs to this class using the same methods as for domestic classes.[105] NERA's recommendation did not differentiate between dependable and opportunity export sales for inclusion in an Export Class. NERA supported this method change recognizing that:

1. exports are a very large share of Manitoba Hydro's business,
2. the revenues from exports can vary widely because of hydro availability and market conditions, and

[102] Specifically Directive 8
[103] Order 7/03 page 97.
[104] PUB Report to the Minister dated March 31, 1988 page 51 and 52, as cited in Board Order 7/03.
[105] Re-filed as PUB-MFR-1 in this proceeding, page 32 & 33.

> 3. the utility specifically plans and operates its system with exports in mind, although it does not currently build solely for export. Inclusion of an export class makes it obvious that the export sales are covering their full embedded cost of service. [106]

At that time, with the export class being ed a full share of generation and transmission costs to all exports (dependable and opportunity) there remained a large Net Export Revenue excess that NERA considered. NERA recommended that these Net Export Revenues be allocated to customer classes in a way that broadly shares the large net benefits of the Province's exports (e.g. in the proportion to the domestic classes total allocated costs of generation + transmission + distribution).[107]

Hydro finally implemented the export class until PCOSS06.[108] Though Hydro did implement the class pursuant to Board Order 7/03, Hydro provided a different rationale than that cited by the Board - Hydro's justification was as follows:

> Manitoba Hydro implemented an export class to moderate potentially unfair class revenue requirements that occurs from incorporating significant revenue generated from selling surplus energy at market prices above embedded (original accounting costs) cost in the cost of service study. The cost of service study does not drive export rates. The intent of the export class is to give adequate cost recognition to exports such that the residual export revenue can be used to moderate the distortions.[109]

In short, compared to the Board's objective of tracking costs to export and ensuring domestic customer were not subsidizing export sales, Hydro's objective was focused on defining a clear and positive Net Export Revenue that could be used to address "distortions" that Hydro viewed existing in the Cost of Service model.

By the 2006 Cost of Service review, Hydro recommended the adoption of the NERA Report method with the one modification of splitting the export class into two subclasses: one export class for firm exports and another for opportunity exports.[110] Hydro proposed to allocate costs on the same basis as domestic classes for the firm export class (with no direct assignment of costs) and assign only variable costs to the opportunity export class noting that:

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[106] Re-filed as PUB-MFR-1 in this proceeding, NERA Report on Classification and Allocation Methods for Generation and Transmission in Cost of Service Studies, page 30.

[107] Re-filed as PUB-MFR-1 in this proceeding, NERA Report on Classification and Allocation Methods for Generation and Transmission in Cost of Service Studies, page 57.

[108] PCOSS06, page 5-6.

[109] PUB/MH-I-2b

[110] Re-filed as PUB-MFR-4 in this proceeding: PCOSS06 (September 2005), page 17.

> …opportunity sales rely on water flows which are above dependable and are made only as short-term surpluses allow. It is true that some Manitoba Hydro facilities are designed to permit the use of flows which are above dependable levels to facilitate exports. These include additional generating capability at some Generating Stations as well as additional Transmission capacity. However, these incremental facilities are placed in service at much below average cost of Generation and Transmission facilities and are, in any event, used to serve domestic or other firm loads on a priority basis. Given the difficulty of precise identification of these facilities and their cost, and given that firm exports continue to be costed at a full share of embedded cost, it is not greatly inaccurate to assign opportunity sales only the variable costs such as imports, water rentals and thermal fuel cost.[111]

Hydro also recommended the allocation of Net Export Revenue as per NERA's recommendation, allocating on the basis of total allocated costs of all functions, not just Generation and Transmission costs.[112]

The PUB in Decision 117/06 rejected Hydro's proposal for two separate export classes, finding no sufficient reason or differing characteristics pertaining to firm and opportunity sales to support two export classes and directed only one export class be established. The two subclasses were rejected for the following reasons[113]:

- There was strong evidence that opportunity exports are only achievable as a result of over-building hydraulic generation facilities relative to immediate domestic need, supporting the assignment of embedded costs to opportunity exports.
- Firm sales are made from dependable energy only (including imported power capabilities) with additional export sales secured each year on the basis of more favourable than anticipated hydraulic generation. Inherently, Hydro expects higher load than dependable requirements for planning purposes, therefore some level of opportunity exports could be considered dependable. Failure to achieve some portion of these sales in one year out of ten, due to drought, does not necessarily make these sales less firm because in most years these loads are supplied by surplus hydraulic energy.
- Hydro suggested that new plant design for hydraulic generation is not significantly influenced by export consideration but evidence suggested that approximately 35-40% of plant capacity provides for some firm exports in drought years, but primarily serves opportunity export sales.

[111] Re-filed as PUB-MFR-4 in this proceeding: PCOSS06 (September 2005), page 17.
[112] Re-filed as PUB-MFR-4 in this proceeding: PCOSS06 (September 2005), page 19.
[113] Re-filed in this proceeding, Order 117/06 (August 2, 2006), summarized from pages 49-51

- Required capacity overbuilds for dependability purposes will always be available for exports, those being primarily opportunity sales.
- While Hydro's expansion plans are designed to serve domestic load, Hydro's strategy for future generation resources is for new generation to be put into service to achieve some firm exports and, in most years, significant opportunity export sales, with generally a period of approximately ten years when new facilities or capacity serves exports, and that the new plant may even initially entirely be for exports, declining thereafter.
- NERA originally recommended one export class treating all export loads on a comparable basis to domestic load, which is not inconsistent with the way export customers view the sales commitments of Hydro as MISO's requirement for financial firm sales blurs distinctions between domestic load and firm or opportunity export sales.

The Board specifically noted: "While MH described net export revenue as a "windfall", the Board saw exports as a natural outcome of Hydro's planning and operations."[114]

Export continued as a single class until methodology changes were adopted by Hydro in PCOSS13.

DIRECT ASSIGNMENT TO THE EXPORT CLASS

In PCOSS08, filed as part of the 2008/09 General Rate Application Hydro directly assigned the following costs to the export class:

- Uniform Rate Adjustment ($17 million)
- DSM costs ($25 million)
- Trading Desk costs ($13 million)
- MAPP/MISO/NEB costs ($7 million)
- Imports and other purchased power ($134 million)
- Thermal fuel costs ($23 million)

As per the PUB's Order 117/06, Hydro allocated a portion of generation (including water rentals) and transmission to the export class as well. However, Hydro took issue with the magnitude of costs assigned/allocated to the export class. Also, as the costs of imports, purchased power, DSM and thermal fuel were all assigned to exports, Hydro effectively proposed to credit the export class with the kW.h derived from these sources, and deduct the associated energy amounts for these costs from the total

[114] Board Order 117/06, page 51

export load at generation using in allocating common costs. This resulted in the share of export sales participating in bulk power cost allocation decreasing from 8,462 GW.h to 4,524 GW.h at the time.[115]

PUB Order 116/08 amended the 117/06 direct assignments to export, by directing that all fuel costs and 50% of the fixed costs of the thermal and coal plants to be allocated to the Export class. The Board also directed Hydro to remove energy savings reduction of DSM from export and reapply to the domestic classes to determine the percentages for generation cost-sharing.[116] In effect, the Board accepted that exports should pay for the DSM programs, but did not accept the logic that by doing this exports acquired a right to claim the DSM energy.

As before, Hydro cited that any method for export cost allocation should not result in costs to exports being higher than the costs to serve GSL >100kV customers. In response, the PUB rejected Hydro's argument, and noted that domestic load has covered the past investments in G & T and is entitled to 'heritage rates', hence exports should reflect a higher cost, implicitly carrying above average costs, which is part would be associated with cost of newer assets. The PUB directed PCOSS methods out of 116/08 were considered to fall between the two positions, with imports and thermal fuel assigned to exports while allowing exports to share in the overall blended costs of generation and transmission. The Board accepted the risk that it's ruling on cost assignment to the export class (particularly for assigning thermal costs) may result in zero or negative net export revenues in some future years.[117]

Hydro filed PCOSS10 and PCOSS11 as part of the 2010/11 & 2011/12 General Rate Application. The COS studies proposed many changes from the last PUB approved methodology, including[118]:

- A changed assignment of DSM costs, from directly assigned to the export class to direct assignment to individual domestic customer classes who participated in the DSM (except for the AEF which was still assigned directly to the export class).
- Assignment of gas-fired generation entirely to domestic classes with fuel and variable maintenance costs for Brandon Unit 5, other than that related to operation necessary for staff proficiency training and reliability runs, assigned to the export class. For PCOSS11, Hydro changed this further to allocate Brandon GS fuel to domestic classes only.[119]
- Trading Desk and MISO fees from 100% export direct to 42% export direct, 58% domestic pooled.

[115] Order 116/08 (July 29, 2008), page 255
[116] Order 116/08 (July 29, 2008), pages 268 - 271
[117] Order 116/08 (July 29, 2008), pages 271 - 273
[118] Summarized from PCOSS10 (November 30, 2009), pages 2 & 7
[119] PUB-MFR-13 Tabular Progression for Prospective Cost of Service Study 2006 to 2014

- PCOSS10 & PCOSS11 included a single export class, allocated generation and transmission costs on the same basis as to domestic customers after adjustments to energy for imports and thermal generation.

The PUB did not approve or deny any changes in Order 5/12 stating that:

> MH has chosen not to seek differential class rate increases other than for Area and Roadway Lighting. MH's principles of rate design and cost allocation should be kept current. That said, the Board's position should not be interpreted to imply any support for the Cost of Service methodology changes employed by MH in PCOSS10 and PCOSS11.
>
> In previous Board Orders, MH has been directed to treat all exports as a defined business venture obligated to share fully in the Utility's embedded costs. The Board has not accepted and does not accept the concept of any exports being a free byproduct of domestic power operation.
>
> Exports come with a cost, and that cost needs to be recognized in calculating net export revenue and in developing a business plan for new generating stations and transmission assets.
>
> Reliability benefits associated with the HVDC system flow to export customers as well as domestic customers. Allocation of zero Bipole III costs to exports ignores these benefits and the role that Bipole III plays in facilitating exports from northern generation.
>
> In the Board's view, MH's Export Business Model cannot transfer all operational and market risks to domestic customers. Because export contracts and opportunity sales carry greater risks than domestic sales, such export sales must provide a contribution to MH's fixed costs.[120]

The Board also noted that a separate COSS review may be necessitated if Hydro seeks changes to the currently approved Board methodology (i.e. COSS methods approved/denied in Order 116/08).

PCOSS13 was filed along with the 2012/13 and 2013/14 General Rate Application[121] after Christensen Associates Energy Consultants (CA) performed a review of its Cost of Service Methodologies. PCOSS13 proposed the following changes (on top of the changes proposed for PCOSS10 and PCOSS11):

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[120] Board Order 5/12 (January 17, 2012), page 213 - 214

[121] Re-filed as PUB-MFR-12 in this proceeding.

- PCOSS13 differentiates between dependable and opportunity export sales with dependable export sales assigned a share of embedded generation and transmission costs and opportunity sales assigned costs of purchased power (less wind purchases) with net opportunity exports (after purchased power is deducted) allocated a share of water rental fees and variable hydraulic generation operating and maintenance.
    - Removing allocated G&T to opportunity exports (including water rentals) results in approximately $19.8 million in reduced export allocated costs.
    - Opportunity exports allocated net water rentals and variable hydraulic generation O&M (after purchased power energy amounts removed) increases costs to exports of approximately $6.1 million.
- Assignment of thermal – natural gas-fired generation from assignment to domestic classes (implemented in PCOSS10) to allocated between domestic and dependable exports (except for Brandon Unit #5 or GS fuel, still assigned to domestic pool).
- Wind purchases ($65.1 million) changed from direct assignment to exports to allocating among domestic/dependable export pool.[122]

The net impact of method changes to the export class specific to PCOSS13 is approximately $79.5 million less costs being allocated to the export class. [123]

Prior to the 2012/13 and 2013/14 General Rate Application hearing, the PUB determined in Order 98/12 that it would review Hydro's Cost of Service methodology by way of a separate process and therefore PCOSS13 was not tested or approved.[124]

EFFECT OF ONGOING METHOD CHANGES ON MEASURED EXPORT COSTS

As a result of ongoing method changes in the measurement of the costs to serve exports, the export cost calculation has been unstable since PCOSS08. Of the changes applied in each respective PCOSS, some were driven by PUB Order, but most were proposed by Hydro and not approved (or not yet approved) by the PUB.

Table B-1 below shows a unit cost comparison for the export class from PCOSS08 (Per Order 116/18) to PCOSS14-Amended. The table highlights that the continual method changes have led to the calculated export cost plummeting from 5.31 cents/kW.h in PCOSS08 (and a full 5.53 cents/kW.h when policy

[122] Summarized from PUB-MFR-12: PCOSS13 (July 2012), page 7
[123] Summarized from PUB-MFR-12: PCOSS13 (July 2012), pages 4 – 7
[124] Board Order 98/12 (August 3, 2012), pages 18 - 19

related costs assigned to exports were included) to a new low of 2.42 cents/kW.h calculated in PCOSS14 Amended, using the new methods proposed by Hydro (2.82 cents/kW.h including policy-related cost assigned to exports). Such a dramatic reduction in the costs of serving export, during a period where Hydro's own costs were largely stable of increasing, suggests a significant and sustained effort to portray a diminished cost responsibility of export sales, in contrast to the earlier PUB benchmark methods set in Order 116/08, the last Order to substantively deal with Cost of Service methods.

Table B-1: Export Cost Comparison PCOSS08 - PCOSS14-Amended[125]

Export Cost Breakdown	PCOSS08 - Per Order 116/08		PCOSS10		PCOSS11		PCOSS13 - w/o method changes		PCOSS13 - w. method changes		PCOSS14		PCOSS14 - Amended	
	($ M)	(cents/ kWh)	($ M)	(cents/ kWh)	($ M)	(cents/ kWh)	($ M)	(cents/ kWh)	($ M)	(cents/ kWh)	($ M)	(cents/ kWh)	($ M)	(cents/ kWh)
Generation Costs														
1 Purchased Power - 1st priority	$140.00	1.82	$174.00	2.20	$120.00	1.68	$103.00	1.40	$103.00	1.40	$90.30	1.00	$0.00	0.00
2 Thermal Power - 1st Priority	$52.00	0.67	$14.00	0.18	$0.00	0.00	$0.00	0.00	$0.00	0.00	$0.00	0.00	$0.00	0.00
3 Allocated Energy - pooled	$129.00	1.67	$149.82	1.90	$132.64	1.86	$104.36	1.42	$104.73	1.43	$137.07	1.52	$194.85	2.16
4 Direct Assigned - other	$71.83	0.93	$52.96	0.67	$70.31	0.99	$132.98	1.81	$73.39	1.00	$88.76	0.98	$73.60	0.82
5 **Total Generation Costs**	**$392.83**	**5.10**	**$390.78**	**4.95**	**$322.95**	**4.53**	**$340.34**	**4.64**	**$281.12**	**3.83**	**$316.13**	**3.51**	**$268.45**	**2.98**
Transmission Costs														
6 Energy Related	$0.00	0.00	$1.64	0.02	$0.00	0.00	$0.00	0.00	$0.00	0.00	$0.00	0	$0.75	0.01
7 Allocated - Demand Related	$45.00	0.58	$50.71	0.64	$44.41	0.62	$46.49	0.63	$26.24	0.36	$29.36	0.33	$21.17	0.23
8 Direct Assigned	$6.10	0.08	$0.00	0.00	$1.92	0.03	$1.61	0.02	$1.61	0.02	$1.70	0.02	$0.00	0.00
9 **Total Transmission Costs**	**$51.10**	**0.66**	**$52.35**	**0.66**	**$46.32**	**0.65**	**$48.10**	**0.66**	**$27.85**	**0.38**	**$31.05**	**0.34**	**$21.92**	**0.24**
10 **Total Cost**	**$443.93**	**5.76**	**$443.12**	**5.61**	**$369.27**	**5.18**	**$388.44**	**5.29**	**$308.97**	**4.21**	**$347.19**	**3.85**	**$290.37**	**3.22**
11 **Total Cost with Policy Adjustments**	**$461.13**	**5.98**	**$466.12**	**5.90**	**$401.30**	**5.63**	**$419.51**	**5.72**	**$340.07**	**4.63**	**$383.52**	**4.26**	**$326.67**	**3.62**
12 **Purchased Power (GWh)**	1,847		1,790		1,385		3,209		2,362		2,839		-	
13 **Thermal Energy (GWh)**	535		287		-		-		-		-		-	
14 **Pooled Energy (GWh)**	5,325		5,824		5,737		4,131		4,978		6,174		9,013	
15 **Total Metered Energy (GWh)**	**7,707**		**7,901**		**7,122**		**7,340**		**7,340**		**9,013**		**9,013**	
16 **Line Losses (GWh)**	755		814		635		658		658		821		821	
17 **Energy at Generation (GWh)**	8,462		8,715		7,757		7,998		7,998		9,834		9,834	
Policy Adjustments														
18 Affordable Energy Fund (AEF)	0.0	0.00	4.0	0.05	12.0	0.17	8.9	0.12	8.9	0.12	12.8	0.14	12.8	0.14
19 Uniform Rate Adjustment	17.2	0.22	19.0	0.24	20.0	0.28	22.2	0.30	22.2	0.30	23.5	0.26	23.5	0.26

[125] PCOSS08 Costs Per Order 116/08 from PUB-MFR-9 with Pooled Energy (GWh) line 13 back calculated after line losses from total energy at generation from Schedule 3 (8,462 GWh) less purchased power (2,028 GWh) from page 6 and thermal (587 GWh) from page 2. Line losses portioned equally on all energy (1st priority, thermal, pooled) and calculated as at generation energy less total metered energy (7,707 GWh) page 6. Same method used to calculate line losses and portion across all energy for PCOSS10 to PCOSS14-Amended. PCOSS10 at generation energy, purchased power and thermal energy provided in PUB-1-145a from 2010/12 GRA, with Total Metered Energy from PUB-1-139a in the same proceeding (amount reported in PCOSS10 Schedule B2 of 7,707 GWh was an error). PCOSS10 energy-related transmission costs for exports is direct-assigned energy related transmission for MISO-MAPP costs. All other values from respective PCOSS schedules.

ATTACHMENT C – RESUME OF PATRICK BOWMAN

PATRICK BOWMAN
PRINCIPAL AND CONSULTANT

EDUCATION: **University of Manitoba**
MNRM (Natural Resource Management), 1998

Prescott College (Arizona)
BA (Human Development and Outdoor Education), 1994

PROFESSIONAL HISTORY:

InterGroup Consultants Ltd. **Winnipeg, MB**

1998 – Present *Research Analyst/Consultant/Principal*

Project development, regulatory and rates, economic analysis and environmental licencing, primarily in the energy field.

Utility Regulation

Conducted research and analysis for regulatory and rate reviews of electric, gas and water utilities in six Canadian provinces and territories. Prepare evidence and review testimony for regulatory hearings. Assist in utility capital and operations planning to assess impact on rates and long-term rate stability. Major clients included the following:

- **For Yukon Energy Corporation (1998-present),** analysis and support of regulatory proceedings and normal regulatory filings before the Yukon Utilities Board. Appear before YUB as expert on revenue requirement matters, cost of service, rate design, and resource planning. Prepare analysis of major capital projects, financing mechanisms to reduce rate impacts on ratepayers, depreciation, as well as revenue requirements.

- **For Yukon Development Corporation (1998-present),** prepare analysis and submission on energy matters to Government. Participate in development of options for government rate subsidy programs. Assist with review of debt purchase, potential First Nations investment in utility projects, and corporate governance.

- **For Northwest Territories Power Corporation (2000-present),** provide technical analysis and support regarding General Rate Applications and related

Public Utilities Board filings. Assist in preparation of evidence and providing overall guidance to subject specialists in such topics as depreciation and return. Appear before PUB as expert in revenue requirement, cost of service and rate design matters, and on system planning reviews (Required Firm Capacity).

- **For Manitoba Industrial Power Users Group (1998-present),** prepare analysis and evidence for regulatory proceedings before Manitoba Public Utilities Board representing large industrial energy users including General Rate Applications and most recently the Needs For and Alternatives To (NFAT) review. Appear before PUB as expert in cost of service and rate design matters. Assist in regulatory analysis of the purchase of local gas distributor by Manitoba Hydro. Assist industrial power users with respect to assessing alternative rate structures and surplus energy rates.

- **For Industrial Customers of Newfoundland and Labrador Hydro (2001-present),** prepare analysis and evidence for Newfoundland Hydro GRA hearings before Newfoundland Board of Commissioners of Public Utilities representing large industrial energy users. Provide advice on interventions in respect of major new transmission facilities. Appear before PUB as expert in cost of service and rate design matters.

- **For NorthWest Company Limited (2004-2006),** review rate and rider applications by Nunavut Power Corporation (Qulliq Energy), provide analysis and submission to rate reviews before the Utility Rates Review Council.

- **For Municipal Customers of City of Calgary Water Utility (2012-2013),** analysis of proposed new development charges and reasonableness of water and wastewater rates.

- **For Nelson Hydro (2013-current),** development of a Cost of Service model.

- **For City of Swift Current (2013-current),** utility system valuation approach.

Project Development, Socio-Economic Impact Assessment and Mitigation

Provide support in project development, local investment opportunities or socio-economic impact mitigation programs for energy projects, including northern Manitoba, Yukon, and NWT. Support to local communities in resolution of outstanding compensation claims related to hydro projects.

- **For Yukon Energy Corporation (2005-current),** Participated in preparation of resource plans, including Yukon Energy's 20-Year Resource Plan Submission to the Yukon Utilities Board in 2005 (including providing expert testimony before the YUB), advisor on 2010 update. Project Manager for all planning phases of the

Mayo B hydroelectric project ($120 million project) including environmental assessment and licencing, preliminary project design, preparation of materials for Yukon Utilities Board hearing, joint YEC/First Nation working group on all technical matters related to project including fisheries, managing planning phase financing and budgets. Assistance in preparation of assessment documentation for Whitehorse LNG generation project.

- **For Northwest Territories Power Corporation (2010-current),** Participate in planning stages of $37 million dam replacement project; appear before Mackenzie Valley Land and Water Board (MVLWB) regarding environmental licence conditions; participate in contractor negotiations, economic assessments, and ongoing joint company/contractor project Management Committee. Provide economic and rate analysis of potential major transmission build-out to interconnect to southern jurisdictions. Conduct business case analysis for regulatory review of projects $400,000-$5 million, and major PUB Project Permit reviews of projects >$5 million.

- **For Northwest Territories Energy Corporation (2003-2005),** provide analysis and support to joint company/local community working groups in development of business case and communication plans related to potential new major hydro and transmission projects.

- **For Kwadacha First Nation and Tsay Keh Dene (2002-2004),** Support and analysis of potential compensation claims related to past and ongoing impacts from major northern BC hydroelectric development. Review options related to energy supply, including change in management contract for diesel facilities, potential interconnection to BC grid, or development of local hydro.

- **For Manitoba Hydro Power Major Projects Planning Department (1999-2002),** initial review and analysis of socio-economic impacts of proposed new northern generation stations and associated transmission. Participate in joint working group with client and northern First Nation on project alternatives (such as location of project infrastructure).

- **For Manitoba Hydro Mitigation Department (1999-2002),** provide analysis and process support to implementation of mitigation programs related to past northern generation projects, debris management program. Assist in preparation of materials for church-led inquiry into impacts of northern hydro developments.

- **For International Joint Commission (1998),** analysis of current floodplain management policies in the Red River basin, and assessment of the suitability of alternative floodplain management policies.

- **For Nelson River Sturgeon Co-Management Board (1998 and 2005),** an assessment of the performance of the Management Board over five years of operation and strategic planning for next five years.

Government of the Northwest Territories **Yellowknife, NT**

1996 - 1998 *Land Use Policy Analyst*

Conducted research into protected area legislation in Canada and potential for application in the NWT. Primary focus was on balancing multiple use issues, particularly mining and mineral exploration, with principles and goals of protection.

PUBLICATIONS: G*overnment Withdrawals of Mining Interests* in Great Plains Natural Resources Journal. University of South Dakota School of Law. Spring 1997.

Legal Framework for the Registered Trapline System in Aboriginal Trappers and Manitoba's Registered Trapline System: Assessing the Constraints and Opportunities. Natural Resources Institute. 1997.

Land Use and Protected Areas Policy in Manitoba: An evaluation of multiple-use approaches. Natural Resources Institute. (Masters Thesis). 1998.

Patrick Bowman Utility Regulation Experience

Utility	Proceeding	Work Performed	Before	Client	Year	Testimony
Yukon Energy Corporation	Final 1997 and Interim 1998 Rate Application	Analysis and Case Preparation	Yukon Utilities Board (YUB)	Yukon Energy	1998	No
Manitoba Hydro	Curtailable Service Program Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Manitoba Public Utilities Board (MPUB)	Manitoba Industrial Power Users Group (MIPUG)	1998	No
Yukon Energy	Final 1998 Rates Application	Analysis and Case Preparation	YUB	Yukon Energy	1999	No
Westcoast Energy	Sale of Shares of Centra Gas Manitoba, Inc. to Manitoba Hydro	Analysis and Case Preparation	MPUB	MIPUG	1999	No
Manitoba Hydro	Surplus Energy Program and Limited Use Billing Demand Program	Analysis and Case Preparation	MPUB	MIPUG	2000	No
West Kootenay Power	Certificate of Public Convenience and Necessity - Kootenay 230 kV Transmission System Development	Analysis of Alternative Ownership Options and Impact on Revenue Requirement and Rates	British Columbia Utilities Commission (BCUC)	Columbia Power Corporation/Columbia Basin Trust	2000	No
Northwest Territories Power Corporation (NTPC)	Interim Refundable Rate Application	Analysis and Case Preparation	Northwest Territories Public Utilities Board (NWTPUB)	NTPC	2001	No
NTPC	2001/03 Phase I General Rate Application	Analysis and Case Preparation	NWTPUB	NTPC	2000-02	No - Negotiated Settlement
Newfoundland Hydro	2002 General Rate Application	Analysis, Preparation of Intervenor Evidence and Case Preparation	Board of Commissioners of Public Utilities of Newfoundland and Labrador (NLPUB)	Newfoundland Industrial Customers	2001-02	No
NTPC	2001/02 Phase II General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2002	Yes
Manitoba Hydro/Centra Gas	Integration Hearing	Analysis and Case Preparation	MPUB	MIPUG	2002	No
Manitoba Hydro	2002 Status Update Application/GRA	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2002	Yes
Yukon Energy	Application to Reduce Rider J	Analysis and Case Preparation	YUB	Yukon Energy	2002-03	No
Yukon Energy	Application to Revise Rider F Fuel Adjustment	Analysis and Case Preparation	YUB	Yukon Energy	2002-03	No
Newfoundland Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2003	Yes
Manitoba Hydro	2004 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2004	Yes
NTPC	Required Firm Capacity/System Planning hearing	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2004	Yes
Nunavut Power (Qulliq Energy)	2004 General Rate Application	Analysis, Preparation of Intervenor Submission	Nunavut Utility Rate Review Commission (URRC)	NorthWest Company (commercial customer intervenor)	2004	No
Qulliq Energy	Capital Stabilization Fund Application	Analysis, Preparation of Intervenor Submission	URRC	NorthWest Company	2005	No
Yukon Energy	2005 Required Revenues and Related Matters Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2005	Yes
Manitoba Hydro	Cost of Service Methodology	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2006	Yes
Yukon Energy	2006-2025 Resource Plan Review	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2006	Yes
Newfoundland Hydro	2006 General Rate Application	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2006	No - Negotiated Settlement
NTPC	2006/08 General Rate Application Phase I	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2006-08	Yes
Manitoba Hydro	2008 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Manitoba Hydro	2008 Energy Intensive Industrial Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2008	Yes
Yukon Energy	2008/2009 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2008-09	Yes
FortisBC	2009 Rate Design and Cost of Service	Analysis and Case Preparation	BCUC	BC Municipal Electrical Utilities	2009-10	No
Yukon Energy	Mayo B Part III Application	Analysis, Preparation of Company Evidence	YUB	Yukon Energy	2010	No
Yukon Energy	2009 Phase II Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	YUB	Yukon Energy	2009-10	Yes
Newfoundland Hydro	Rate Stabilization Plan (RSP) Finalization of Rates for Industrial Customers	Analysis, Preparation of Intervenor Evidence	NLPUB	Newfoundland Industrial Customers	2010	No
Manitoba Hydro	2010/11 and 2011/12 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2010-11	Yes
NTPC	Bluefish Dam Replacement Project	Analysis, Preparation of Company Evidence and Expert Testimony	Mackenzie Valley Land and Water Board	NTPC	2011	Yes
NTPC	2012/14 General Rate Application	Analysis, Preparation of Company Evidence and Expert Testimony	NWTPUB	NTPC	2012	Yes
Manitoba Hydro	2012/13 and 2013/14 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2013	Yes
Manitoba Hydro	Needs For and Alternatives To Investigation	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2014	Yes
Manitoba Hydro	2015/16 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2015	Yes
Newfoundland Hydro	Amended 2013 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2015	No - merged into 2015 General Rate Application
Newfoundland Hydro	2015 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	NLPUB	Newfoundland Industrial Customers	2015	Yes
Manitoba Hydro	2015/17 General Rate Application	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2015	Yes

Manitoba Hydro	2016 Cost of Service review	Analysis, Preparation of Intervenor Evidence and Expert Testimony	MPUB	MIPUG	2016	pending