PROVINCE OF MANITOBA

BEFORE THE PUBLIC UTILITY BOARD

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Manitoba Hydro	**)**
Cost of Service Methodology Review	**)**
	)

REBUTTAL EVIDENCE OF

PAUL CHERNICK

ON BEHALF OF

GREEN ACTION CENTRE

Resource Insight, Inc.

AUGUST 5, 2016

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I. Introduction

Q: Are you the same Paul Chernick who filed initial evidence in this proceeding?

A: Yes.

Q: What is the scope of your rebuttal evidence?

A: I respond to the rebuttal evidence of Manitoba Hydro and the initial evidence of other intervenors:

- Mr. Patrick Bowman on behalf of the Manitoba Industrial Power Users Group ("MIPUG");
- Mr. William Harper on behalf of the Consumers Association of Canada/Winnipeg Harvest ("Coalition");
- Mr. John Todd on behalf of the City of Winnipeg; and
- Mr. A.J. Goulding, Mr. Jerome Leslie and Mr. Ian Chow of London Economics ("LEI") on behalf of GSS and GSM customers.

I also respond to some issues raised in the workshops of May and June, 2016.

Q: What issues will you be discussing?

A: I have organized my evidence into the following groups of issues:

- Cost-allocation philosophy.
- The allocation of DSM costs
- The classification and allocation of generation costs, including the treatment of exports and export revenues
- The functionalization and allocation of transmission costs.
- The sub-functionalization and allocation of distribution costs.

- Customer-related allocators.

II. Cost-allocation Principles

Q: What issues of cost-allocation principles have been raised by the parties?

A: Mr. Bowman and Mr. Todd commented on the basic principles, while the LEI panel suggested that the Board should rely more heavily on the cost-of-service study and adjust classes to more closely match the cost allocation.

Mr. Bowman originates the concept that each asset has an inherent "economic identity" (MIPUG evidence at 2). Much of his evidence focusses on determination of the economic identity for specific facilities, as if economic identity were an important touchstone in cost allocation. In the workshop, Mr. Bowman largely dropped any pretense that economic identity was anything more than a synonym for cost causation, which is determined by a hierarchy of "the rationale for continuing to incur the cost today," "the reason it was originally planned," and "how is it used" (June Tr. 171–172).

Mr. Bowman's fundamental position on the principles of cost allocation thus does not vary substantially from those I advanced. He periodically used the term "economic identity" to suggest that his assertions had an objective reality, but that should be viewed as a rhetorical flourish, rather than explanation.

Q: What are Mr. Todd's positions on the basis of cost allocation?

A: Mr. Todd opined that cost causation is "notional," suggesting that he considered the cost-allocation process as arbitrary (e.g., Ex. COW-9 at 4 and 6, June Tr. 921–922). In the workshop, he clarified that some allocations (such as the president's salary) are "little better than" fiction, but that for many categories of equipment "the causality is very clear" (June Tr. 956).

Having conceded that causality is frequently very clear, Mr. Todd expresses a preference for simple and arbitrary allocators, based on such tenuous arguments as his proposal that "Let's look at the cost driver [for fixed generation costs] as being the load factor of the customers because it's the customers that are causing the investment. So let's get away from looking at the facilities and creating energy and demand splits based on the facilities you happen to have in your system, and let's simply look at customer demand." (June Tr. 958–959). Confronted by the reality that his preferred approach to generation cost allocation would allocate costs exactly the same way, regardless of whether the plants are inexpensive gas steam units or expensive hydro and nuclear, Mr. Todd opined that "I disagree [that] one method's right and the other's wrong. All I'm saying is all these different methods are used. They're all right. They're just different perspectives." (June Tr. 960).

At the end of the day, Mr. Todd abandoned causality for an extreme relativism, which provides the Board with no meaningful guidance and should not influence the Board's decision in this case.

Q: What is the position of the LEI panel on the revenue allocation?

A: The panel asserts that "An RCC [the Revenue-Cost Coverage ratio] of 100% indicates that a customer class is exactly providing the same amount of revenue as the costs associated with serving that class" (GSS/GSM evidence at 12). They argue that the GSS Demand class (at 108%) and the GSS Non-Demand class (at 104.5%) are paying too much, requiring attention in the next GRA. It is not clear to me whether the LEI panel accepts the 95%–105% zone of reasonableness that Manitoba Hydro proposes.

Q: Is LEI correct?

A: They would have a point, if Amended PCOSS14 provided an equitable allocation. Getting to the point where the Board can rely heavily on the cost-of-service study may require another couple GRAs and additional stakeholder consultations, to get Manitoba Hydro to produce and disclose information on loads (e.g., on the common bus, substations, and feeders) and cost drivers (e.g., the length of secondary conductors, the composition of various overhead and general costs).

Even then, it is not clear that the 95%–105% range adequately reflects the uncertainty and approximations in the PCOSS. That can be determined once Manitoba Hydro has developed the data necessary to run a reasonable baseline model, reflecting policy decisions the Board has yet to reach. Modifying assumptions within the range of uncertainty would inform the Board's decision as to how large a deviation of revenues from allocated costs should trigger corrective action in revenue allocation.

III. Demand-side Management

Q: What positions have the parties taken on the allocation of DSM costs?

A: MIPUG supports Manitoba Hydro's direct assignment. On the other hand, the Coalition and GSS/GSM correctly observe that DSM provides system benefits to all customers and propose allocation of DSM as a system benefit.

Mr. Bowman acknowledges that the DSM can be cost-effective for the system but—if directly assigned—not to the participating class, and can be cost-effective for the participating class but—if allocated as a system benefit—not to other classes. (Tr. 201–204) He prefers the direct assignment because he believes that the second condition applies in Manitoba, rather than as a fundamental principle. His position appears to be consistent with mine, except that I would like to see a detailed analysis to support or correct Mr. Bowman's intuition.

Mr. Harper correctly notes that DSM occurs because Manitoba Hydro encourages customers to participate and that DSM reduces overall costs and therefore benefits customers as a whole.[1] He thus suggests that DSM should be treated as a resource consistent with IRP, although he recognizes that participants benefit from reduced bills. (Coalition evidence at 44–45). Mr. Harper's analysis does not account for that additional benefit to the participants' classes. While his factual assertions are generally correct, his conclusion that DSM costs should always be allocated as a system benefit is unfounded.

Mr. Harper's analysis of DSM cost recovery contains one clear error. He claims that:

> If all customers in a rate class were to participate in a particular DSM program then allocating the costs of that DSM program directly to the customer class would effectively "claw back" any financial incentive that was provided to customers and thereby removing their inducement to participate in the first place. (Coalition evidence at 45)

This would only be true under very unusual conditions, such as:

- The class contained only one customer, so that all the costs of the program flowed back to that customer.
- The program does not overcome any real market barriers, such as information or customer time requirements to achieve the efficiency improvement.

[1] Mr. Harper specifically proposes that DSM costs be functionalized in proportion to the avoided generation, transmission and distribution benefits of the programs. (Coalition evidence at 46)

- The program costs more than it saves the participating class.

Most classes contain many customers, so the $100 in program costs for my installation is distributed over thousands of customers, costing me pennies. Most programs provide non-cash benefits to customers, particularly in convenience and overcoming split incentives between customers and various agents (contractors, plumbers, builders, and landlords). Whether program costs exceed the benefits to the participating class is an empirical issue, which I have proposed that Manitoba Hydro investigate.

The LEI panel argues that “Since the benefits of DSM are not confined to the customer class providing the DSM, the costs should be divided across all customer classes to more closely align costs with beneficiaries” (LEI evidence at 11). They recommend that DSM be allocated on demand (June Tr. 751–752), which is a strange choice of allocator, since DSM benefits are primarily energy-related.

Q: What conclusion do you reach with respect to this issue?

A: The evidence advanced by the parties illustrates the wisdom of the approach that I recommended in my original evidence. DSM should benefit the participating classes, without burdening other classes. Manitoba Hydro should determine whether DSM reduces costs to all classes (a) if it is directly assigned to all classes, and (b) if it is allocated in proportion to system benefits. Once the Board has that information, it can select an equitable allocation approach.

IV. Generation

Q: On which generation issues do you provide rebuttal evidence?

A: I respond to the following:

- Mr. Bowman's evidence on generation classification.
- Mr. Bowman's evidence and Manitoba Hydro's rebuttal on the generation allocator.
- The evidence of LEI with respect to the allocation of generation costs to opportunity sales.
- The evidence of LEI and Mr. Todd with respect to the allocation of net export revenues among the rate classes.

Q: Does any of this evidence change your positions on the generation issues in this proceeding?

A: No. Manitoba Hydro generation costs should be classified as energy-related and allocated on the weighted energy factor without any capacity adder.

A. Generation Classification

Q: What is MIPUG's proposal regarding the classification of generation costs?

A: Mr. Bowman proposes that 21%–23% of fixed generation costs (other than wind) and generation-related transmission be classified as demand-related (MIPUG evidence at 19–22).

Q: What is his basis for that recommendation?

A: He derived the 21% value with the system load-factor method from data around 2003, and the 23% from a comparison of the cost of a rather expensive combustion turbine to an unnamed hydro plant.[2]

[2] His source for the cost data is a slide from a Manitoba Hydro presentation, provided in PUB-MFR-17, p. 101. Mr. Bowman does not know how the costs were computed or how long a combustion turbine could be expected to last (June Tr. 180–182).

Mr. Bowman's underlying justification for classifying generation partly to demand is that generation provides capacity, as well as energy (MIPUG evidence at 19). He cites Manitoba Hydro's discussion in the NFAT filing that adding Conawapa (in Manitoba Hydro's Preferred Development Plan) would provide "the ability to better carry peak loads" and that the improved value of the Preferred Development Plan over the All Gas scenario in the NFAT filing is "primarily due to added generation," and concludes that Manitoba Hydro's hydro investments are thus demand-related (ibid at 22).

Q: Is there any merit to Mr. Bowman's argument?

A: No. The system load-factor method has nothing to do with cost causation, and as I demonstrated in my initial evidence (at 24) the capital cost of a peaker is only about 8% of the estimated cost of Keeyask.

More fundamentally, Mr. Bowman glosses over the reality that Manitoba Hydro adds capacity to meet firm energy requirements and that those additions have been adequate to serve peak demand. No additional generation capacity has been required to meet peak. He attributes the cost of generation to the side-benefit of increased demand-carrying capability, rather than to the major driver, energy. With respect to the supposed capacity benefit of Conawapa, Undertaking No. 31 demonstrates that the Preferred plan provides a large amount of surplus load carrying capability, but the alternative plans would all provide adequate capability. Conawapa's additional energy might be valuable for exports, but the capacity would be entirely excess.[3] Any reliability benefit of the Preferred plan over the All-Gas alternative was due to the addition of the US interconnections to supply

[3] In any case, the Board rejected Manitoba Hydro's proposal to build Conawapa.

energy in drought conditions, not due to the excess generation capability.[4] (June Tr. 183–184)

Manitoba Hydro's generation investments (including associated transmission) are driven by energy, and the costs should be allocated on energy.

B. Allocator for Generation

Q: Which parties commented on the allocation of generation costs?

A: The Coalition joined GAC in opposing the inclusion of an arbitrary capacity component in the weighted energy allocator. The Manitoba Hydro rebuttal defended that inclusion. MIPUG proposes to allocate the portion of generation cost classified as demand related on a single annual CP hour.[5]

Q: Does the Manitoba Hydro rebuttal add any new information regarding the generation energy allocator?

A: Manitoba Hydro largely repeats its previous explanations (Rebuttal at 18–19, 21). The Rebuttal does not provide a rationale for including any capacity weighting at all in the years prior to the establishment of the MISO capacity market, or for using a capacity price since 2006 that is much higher than the MISO capacity price at which Manitoba Hydro could sell additional capacity. Nor has Manitoba Hydro established that its ability to sell capacity in the MISO market is constrained by domestic load; just as Manitoba Hydro has

[4] One issue in the NFAT proceeding was whether the US contracts and the US transmission additions could be pursued without Keeyask; Manitoba Hydro did not include the contracts or transmission in the All-Gas case.

[5] Manitoba Hydro responds to the weaknesses in the MIPUG case. Since there is no basis for classifying any fixed costs on demand, I do not discuss this issue further.

more peak capability than it needs for firm load, Manitoba Hydro may have more peak capability than it can sell to MISO.

Q: Does the Manitoba Hydro rebuttal respond to your evidence that MISO's reported prices for energy by time and season have a pattern significantly different from the SEP data that Manitoba Hydro uses?

A: No.

Q: What do you recommend the Board do with respect to the energy weightings?

A: The Board should reject the addition of an arbitrary capacity adder to the peak periods, and should order Manitoba Hydro to provide energy weights based on both the SEP data and the MISO price data for the Manitoba node, as part of its GRA filing. Manitoba Hydro should also provide data on the pattern in which it sells opportunity energy (e.g., in monthly, weekly, daily, or hour blocks), so that the Board can determine what mix of the week-ahead SEP data and the day-ahead and real-time MISO data are most representative of the value of energy by period.

C. Allocation of Generation to Opportunity Exports

Q: What issues have been raised with respect to the allocation of generation costs to exports?

A: The initial evidence of GSS/GSM (at 7) and MIPUG (at 11) advocate allocating a share of fixed generation and transmission costs to opportunity sales based on claims that are summarized by the LEI panel:

> Since the acceleration of this generation investment [Keeyask] was justified under the assumption of sustained export sales, it effectively assumes that opportunity export sales are not sporadic, but are a reliable source of income (LEI evidence at 7).[6]

Q: Are these assertions correct?

A: No. There is no evidence that any generation was ever accelerated due to opportunity sales. The LEI panel was unable to identify any such decision in the workshop. (June Tr. 801) In Undertaking 34, the LEI panel "submitted that opportunity exports played a role in advancing…Limestone and Wuskwatim generation stations as well as…Keeyask," compared to the need date for domestic energy requirements. The evidence offered in that undertaking indicates that:

- Limestone was advanced one year to support firm exports and another year for "the profitable sale of additional interruptible energy," which may have been contracted surplus energy or opportunity sales.
- Wuskwatim was advanced eight years "to obtain additional export revenues and profits," but LEI was unable to find a source that identified opportunity exports as driving the timing of Wuskwatim.
- Keeyask was approved for a 2019 in-service date, five years before the Board's estimate of domestic need.[7] The Undertaking cites a Manitoba Hydro statement that the advancement of the Keeyask project "facilitates higher value export sales" and a Manitoba Hydro projection of higher average revenues from opportunity sales than firm sales in the

[6] The LEI panel also asserted that opportunity sales can affect generator sizing and system design (Tr. 799), but LEI did not provide any examples of this hypothetical effect in Manitoba.

[7] Undertaking 34 says that the Board found that new generation would be required for domestic load "after 2024." In fact, the Board found that new generation "will likely be required *no later than* 2024" (Panel Final Report at 249).

period from 2020 to 2040. LEI does not provide any evidence that opportunity sales affected the Board's decision on Keeyask timing.

Fortunately, the Board explained its reasons for accepting Manitoba Hydro's proposed earlier date for Keeyask:

> Cancelling the Keeyask Project now would result in material consequences for ratepayers, because Manitoba Hydro would have to recover the $1.4 billion spent on the Project to date. The arrangements with First Nations would have to be terminated and significant economic opportunities lost. Manitoba Hydro's commercial reputation may suffer. The Keeyask general civil contract would have to be renegotiated and cancellation fees may be payable.
>
> Even changing the timing of the Keeyask development could present challenges and commercial consequences. Agreements and understandings either embedded or underlying export contracts would be affected. This could lead to future negotiation consequences. (Needs For and Alternatives To Review of Manitoba Hydro's Preferred Development Plan–Final Report, June 20, 2014, at 247)
>
> The Panel considered the question of the in-service date and, in light of the potential impacts of Demand Side Management initiatives, whether to recommend deferral of the start of Keeyask's construction. The Panel notes the need for new capacity as a result of load demands associated with expected new pipeline construction. Agreements also have been signed with the Keeyask Cree Nations that could be adversely affected by delay. As a result, the Panel found no convincing reason to delay the in-service date of 2019 for the Keeyask Project. (ibid at 250)
>
> Manitoba Hydro dramatically increased its projected DSM savings in the course of the NFAT Review. The Panel is uncertain that these projections can be achieved by Manitoba Hydro. However, this risk is mitigated by the Panel's recommendation to proceed with a 2019 in-service date for the Keeyask Project, which will provide sufficient energy and capacity to meet needs if projected savings do not fully materialize. (ibid at 22)
>
> If the pipeline load materializes, this will increase pressure on Manitoba Hydro to achieve its Demand Side Management targets, as it will reduce the available generation surplus. However, advancing the construction of the Keeyask Project to 2019 mitigates this risk by providing additional surplus capacity. (ibid at 201)

The Board's reasons for approving the earlier date for Keeyask conspicuously omit any mention of opportunity sales.

Hence, it appears that "interruptible energy" sales (which may be contracted, rather than opportunity, sales) resulted in the advancement of Limestone by one year (from 1991 to 1990), and that the timing of Wuskwatim and Keeyask depended only on domestic and contract load.

Q: If any of these plants had been advanced due to opportunity sales, what portion of their costs would be allocable to opportunity sales?

A: Zero. The advancement of Limestone (and Wuskwatim, if that were relevant) would have reduced the cost of those plants in PCOSS14 and later cost-of-service studies. The costs of Keeyask are not in PCOSS14; its costs will be relevant starting in PCOSS19, and its advancement will decrease costs starting in PCOSS24.

Q: What about the claim that opportunity sales are reliable?

A: No. The LEI initial evidence (at 8) asserts that they had statistically determined that less than 3,390 GWh of excess hydro energy would be available for opportunity sales only once in 162 years. This assertion did not survive scrutiny.

The panel selected a period of just ten historical years, plus five years of forecasted average data. The forecast data reflect average rather than random hydrological conditions, reducing the variance in LEI's overall data. In the workshop, other parties' experts pointed out that LEI had used forecasted data with no hydrological variability and had used such a short historical period that they had missed drought conditions (June Tr. at e.g., 802–804, 879–880).

Q: Did the LEI panel correct their statistical analysis?

A: In Undertaking 35, the LEI panel corrects some of these errors, using 16 years of historical data. This analysis still predicts that opportunity sales would be greater than 1,500 MWh in 161 out of every 162 years, even though opportunity sales were less than half that level in 2003/04. LEI understated the variability in opportunity exports by conducting its analysis on total exports, so the higher contract sales (which should not be affected by droughts, so long as Manitoba Hydro can purchase energy to fulfill its obligations) in the early 2000s helped offset the drop in opportunity sales.

Q: Has the Board previously addressed the dependability of opportunity sales?

A: Yes. In the 2006 cost-of-service study review, the Board said:

> MH has experienced favourable flow conditions (average or above) for hydraulic generation in four of the last five years; nine of the last ten years; and thirteen of the last fifteen years. Since the Limestone generating station came into service in 1990, MH has only experienced two severe drought years, and has consequently been able to sell substantial energy to the export market on an almost continuous basis.
>
> Ninety years of flow history provides a good perspective on the potential for significant drought events. Variable degrees of drought events have happened in about 20% of the years, with severe droughts having occurred in approximately 10% of the years. Extended severe droughts (those extending two years or more) have occurred at least three times. The 2003-04 drought had severe financial implications on MH… (Order 117-06 at 41)

The LEI panel appears to have been unaware that they were using a particularly drought-free period in their analysis.

Q: What is your conclusion regarding this issue?

A: Opportunity exports should not be assigned any fixed generation or transmission costs.

D. Use of Net Export Revenues

Q: What positions do other parties take regarding the allocation of net export revenues?

A: Mr. Bowman advocates that Manitoba Hydro retain the net export revenues and establish a reserve fund to stabilize rates when droughts occur (MIPUG evidence at 47–50).

Mr. Todd and the LEI panel propose that the net export revenues be allocated in proportion to total costs, including direct assignments, rather than only to the costs distributed among classes through factor allocations. (COW evidence at 4–5, GSS/GSM evidence at 8–10) The witnesses acknowledged that street lighting equipment, which is not part of Manitoba Hydro's monopoly service, should logically be excluded from the allocation of net export revenues (COW evidence at 5, June Tr. 810).

Q: What are your responses to these suggestions?

A: Mr. Bowman's proposal would raise rates now and reduce rates during and following droughts. This change would likely reduce the conservation price signal during a prolonged drought, which would be unfortunate.

It is unlikely that many customers would prefer to pay Manitoba Hydro extra in 2017, with the promise of repayment in the future. If the large industrial customers are interested in having Manitoba Hydro sequester some funds for them, they should be working with Manitoba Hydro to prepare a class-specific or customer-specific drought savings account.

On the other hand, the inclusion of the direct-assigned costs in the allocation of net export revenues seems appropriate, if it is limited to the costs that reflect utility service.[8] If the analysis of DSM cost effects (as I discuss in Section III) results in a decision to directly assign DSM costs to the participating classes, DSM costs should probably be included in allocation of net export revenues, depending on whether that allocation would still result in equitable effects across classes.

V. Transmission

Q: On which transmission issues do you provide rebuttal evidence?

A: I respond to the evidence of Mr. Bowman on generation-related transmission and the treatment of the US interties, and to Manitoba Hydro's rebuttal on the treatment of subtransmission.

Q: Have any of the evidence to date changed your recommendations regarding transmission issues?

A: No. I recommend that:

- The following facilities should be functionalized and classified as part of generation: Bipole III and Dorsey HVDC facilities; the Wuskwatim 230-kV lines; the facilities I identify in Tables 4 and 5 of my initial evidence; the generator switching stations at Wuskwatim, Kelsey, Pointe du Bois, Slave Falls, McArthur Falls, and Seven Sisters; and the Radisson-Kelsey 230 kV line.

[8] DSM costs are not necessarily a monopoly utility service; non-utility entities deliver ratepayer-funded DSM in several jurisdictions, including Nova Scotia, Maine, Vermont, Wisconsin, Oregon, Hawaiʻi, Connecticut, District of Columbia, and to some extent California and New York. Even in Manitoba, customers can purchase efficiency from many suppliers. But the DSM that Manitoba Hydro acquires to reduce total costs provides a utility service and should be eligible for an allocation of net export revenues.

- That additional transmission facilities be subject to functionalization as generation-related as additional data become available.
- Subtransmission be functionalized, classified and allocated with all other load-related transmission.

A. Generation-Related Transmission

Q: What are Mr. Bowman's recommendations regarding the functionalization of transmission?

A: Mr. Bowman (MIPUG evidence at 28-30) accepts Manitoba Hydro's treatment of Bipole I and II as generation-related, agreeing that these lines are integral to investment in generation stations and would have no purpose without it. He proposes that generator outlet transmission, in particular, the Wuskwatim outlet lines to the Wuskwatim switching station, be shifted to the generation category. On the other hand, Mr. Bowman rejects Manitoba Hydro's treatment of the Dorsey Converter Station and Bipole III as generation-related.

Q: Do you agree with Mr. Bowman that the Wuskwatim outlet lines should be considered generation-related?

A: Yes. However, Mr. Bowman has singled out a relatively minor part of the transmission associated with Wuskwatim. Additional lines should also be treated as generation. Four major transmission lines were built to tie Wuskwatim to the system. The three outlet lines picked out by Mr. Bowman would be completely useless and Wuskwatim would be completely useless, if at least some of the four transmission lines connecting Wuskwatim to the grid had not been built.

Q: What is Mr. Bowman's rationale for rejecting Manitoba Hydro's treatment of Dorsey as generation-related?

A: In Mr. Bowman's view, Dorsey provides some non-zero "value to the system beyond purely converting DC power to AC." He takes the position that as long as Dorsey serves some transmission function, it should be considered 100% transmission-related (MIPUG Evidence at 28–29).

Q: What is MIPUG's rationale for rejecting Manitoba Hydro's treatment of Bipole III as generation-related?

A: Mr. Bowman makes the following arguments:

- Unlike Bipole I and II, Bipole III was not integral to the planning of Keeyask and future generation (MIPUG Evidence at 30).
- Winter peak and winter shoulder loads, not energy, drive the need for Bipole III. (Ibid. at 32, June Tr. 194)
- Bipole III is a "transmission solution to a transmission problem" (June Tr. 256). In the event of an outage of Bipole I and II or Dorsey, the system will experience significant capacity shortfall. (MIPUG Evidence at 30–31).

Q: Does Mr. Bowman's approach to the functionalization of Dorsey and Bipole III properly reflect Manitoba Hydro's generation and transmission planning process?

A: No. The crucial consideration in the functionalization of Dorsey and Bipole III is that these facilities were required by the decision to build energy-saving hydro generation far north; if instead Manitoba Hydro had built a gas-fired combined-cycle plant in Winnipeg, it would not have needed Bipole III. Mr. Bowman acknowledges this reality (June Tr. 189).

Q: Do Mr. Bowman's arguments concerning Bipole III have merit?

A: No, for the following additional reasons:

- As Manitoba Hydro makes clear in its rebuttal evidence (at 22–24), Bipole III is needed to ensure reliable energy supply in both the summer and winter.
- Bowman acknowledges that his proposed change to the COSS would lead to a reduction in the allocation of Bipole III to exports, a result that is inconsistent with the "the policy framework for the project that export revenues would cover the costs of the project." (MIPUG Evidence at 33)
- The capacity deficit without Bipole I and II that Mr. Bowman points to in his initial evidence actually existed right from the beginning, all the way back to 1985 (MIPUG evidence at 30–31 and Figure 1; June Tr. 190–191). When the northern generation was developed, Manitoba Hydro may have lacked the financial resources to build Bipole III and achieve the level of reliability of energy that might be desirable. With the passage of time and the prospect of developing additional northern generation, Manitoba Hydro decided it was time to improve the energy delivery. This was a built-in problem that goes back to the beginning of the northern system.

B. Allocation of Transmission Costs

Q: What issues have arisen regarding the allocation of transmission costs?

A: MIPUG (Evidence at 3, 33) advocates allocating the US interconnections on demand, rather than weighted energy.

Q: What is your response to this proposal?

A: I strongly disagree with MIPUG on this issue. The investments in the US interconnections are primarily driven by the opportunity for export energy sales and to provide back-up energy imports from the US during droughts. These are energy-related benefits and the costs should be allocated on energy.[9]

C. Subtransmission

1. The Role as Subtransmission

Q: In your initial evidence, what was your position on the functionalization of subtransmission?

A: I explained that subtransmission plays the same role as higher-voltage transmission and represents a substitute for that higher-voltage transmission. Far from adding to the cost of serving customers, the subtransmission system reduces those costs. There is thus no basis for functionalizing subtransmission as an extra function and charging all customers served at less than 100 kV for their load share of transmission over 100 kV, plus a share of the transmission less than 100 kV.

Q: What parties have provided evidence on the subtransmission?

A: Only the Manitoba Hydro Rebuttal commented substantively on this issue, defending its subtransmission functionalization and the double-charging of most customers.[10]

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[9] Manitoba Hydro's rebuttal evidence makes much the same point.

[10] In addition, Mr. Harper indicated in his evidence that the treatment of subtransmission in Amended PCOSS14 "is consistent with industry norms" (Coalition Evidence at 74), but he

Q: What is Manitoba Hydro’s defense of its position?

A: Manitoba Hydro makes five points.[11] Each of those points supports my position or is irrelevant to the issue.

First, Manitoba Hydro asserts that the combination of the <100 kV and >100 kV equipment does not constitute a unitary system, because they work together, with the high-voltage lines directly serving some areas and the lower-voltage transmission extending service from the high-voltage lines to other areas. The system that Manitoba Hydro describes is the unitary system I described in my evidence: the subtransmission equipment replaces the pricier high-voltage equipment in areas where that is feasible. This point supports my position.

Second, Manitoba Hydro apparently attempts to rebut my statement that 35% of distribution load is supplied through substations served directly from high-voltage transmission, by pointing out that “this does not comprise the majority of all distribution customers. The reality is that a large percentage of distribution customers are served from portions of the distribution system that are supported by subtransmission lines and stations.” Manitoba Hydro is correct that 35% is not a majority.[12] My evidence proposes that (should the Board approve the unjustified separation of subtransmission from other transmission), 35% of distribution should be treated in the same manner as the >100 kV GSL customers. This point in Manitoba Hydro’s rebuttal is irrelevant, since it basically summarizes my initial evidence.

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indicated at the workshop that my position was “intriguing” and “worth exploring” (June Tr. at 401–403).

[11] Manitoba Hydro combines its second and third points into its paragraph 2 (page 28).

[12] I provide data, while Manitoba Hydro responds only in generalities, but those generalities are consistent with my data.

Third, Manitoba Hydro points out that there are "stations that convert subtransmission voltage…to distribution voltage levels" and that "where distribution customers are served from substations that convert direct from transmission voltage, Manitoba Hydro incurs costs for transmission voltage to distribution voltage reductions. On the other hand, customers who accept service at voltages > 100 kV bear the cost of transformation to their utilization voltage" (Rebuttal at 28). These statements correctly explain why customers served at distribution voltage should pay for distribution substations (which no party disputes), and are entirely irrelevant to the issue of whether distribution customers should be charged extra for saving Manitoba Hydro the costs of additional kilometres of high-voltage transmission.

Fourth, Manitoba Hydro agrees that some generation is connected through lines of less than 100 kV, and agrees with me that those facilities should be functionalized as generation.[13]

Fifth, Manitoba Hydro accepts my analogy between the subtransmission lines and the radial transmission lines, but suggests that something is wrong with its allocation of the latter. Manitoba Hydro does not explain why it thinks its allocation of the radial transmission lines is in error, so I cannot comment further.

Q: Since Manitoba Hydro does not appear to understand your points about the unitary nature of the transmission system or the complementary

[13] Manitoba Hydro does not dispute functionalization as generation of any of the transmission lines I identify as generation-related in my initial evidence (at 31–37), but the <100 kV lines are the only ones that Manitoba Hydro explicitly endorse refunctionalizing.

nature of the <100kV and >100kV facilities, can you explain those points again.

A: Yes. Figure 1 illustrates a simple portion of a transmission system, with 115 kV lines on towers serving distribution substations or industrial customers at points B and E. For the station at point D, the utility is able to use a less expensive 66 kV line for part of the distance. If the level of the load at D required that the 115 kV system be extended, costs would rise. The 66 kV line saves money; if one class is served only at point D, and another at point B, the total transmission charge (for all voltage levels) for the former should be lower.

Figure 1: Subtransmission as Alternative to >100 kV Transmission

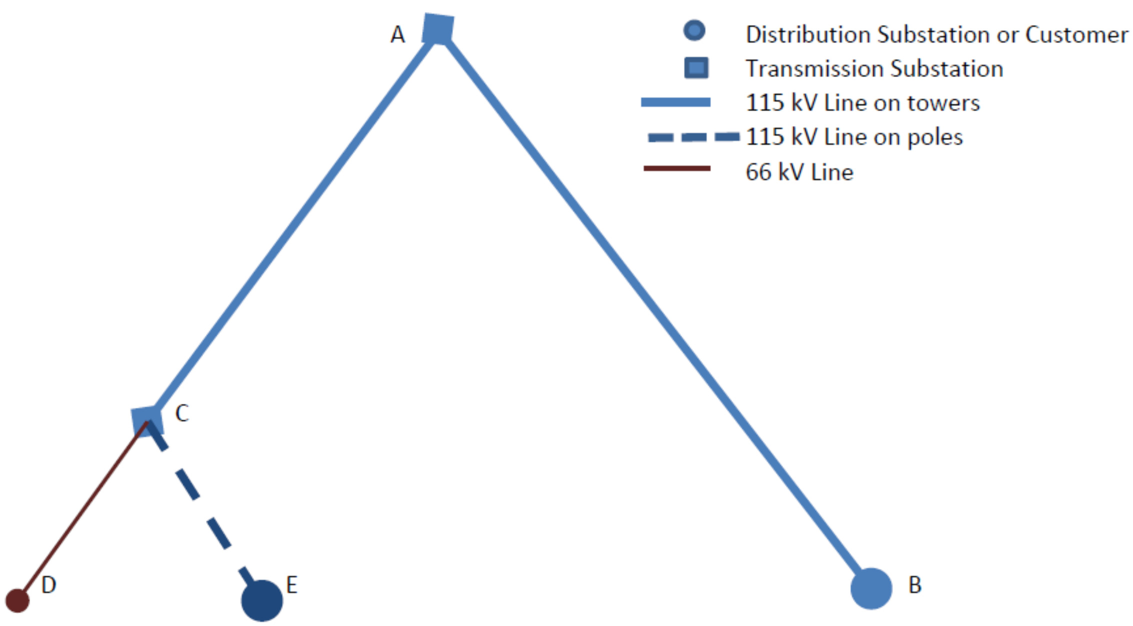

Figure 1 also illustrates a second point. There are many distinctions among transmission lines, other than voltage, including height, vintage, overhead/underground, and support design. They all serve the same function. Manitoba Hydro arbitrarily selects voltage to split off a portion of the system to be billed only to selected classes, but it could have chosen any of the others. For example, in Figure 1, point E is served by a different design of 115 kV line. A class served only at point B (or otherwise directly from 115 kV lines on towers) could argue that it does not use the 115 kV on poles, and should not be charged for that equipment. Yet all three delivery points—B, D and E—receive the same service, and point B may well be the most expensive to serve.

2. Subtransmission Serves Many Classes

Q: Has any party provided any evidence supporting the use of the NCP for allocation of the subtransmission system?

A: No. No other party discussed the drivers of subtransmission in the initial evidence, and Manitoba Hydro did not respond to my evidence in its rebuttal. At this point, the record is clear that some allocator based on the coincident peaks on the subtransmission facilities would be appropriate. I discuss this issue further in Section VI.A.

VI. Distribution

Q: On which distribution issues do you provide rebuttal evidence?

A: None of the intervenors filed evidence on the functionalization, classification or allocation of distribution costs. Manitoba Hydro's rebuttal addresses my evidence on the allocation of substations.

At this point, I consider my initial evidence to be uncontested, indicating that the Board should accept my recommendations that:

- The sub-functionalization of distribution to secondary (which affects the allocation of costs between the GSL <30kV class and all other distribution classes) should be reduced from 30% to 20%.
- Distribution poles and wires should be classified as 100% demand-related.
- Distribution substations should be allocated on monthly peaks, weighted by substation peak loads, as I discuss further in Section VI.A.
- Primary lines should be allocated on coincident peaks of distribution-level classes (all but GSL >30 kV). Until feeder-level peak data are available, feeders should be allocated on substation peak loads.

A. Allocation of Substations

Q: Does Manitoba Hydro disagree with your observations that multiple classes use each distribution substation, that class NCP is not an appropriate allocator for substations, and that those costs should be allocated in proportion to the coincident high-load hours on the substations?

A: No. Manitoba Hydro says that "there may be some merit in exploring the alternative allocation procedure recommended by Mr. Chernick" (Rebuttal at 30), which is about as favorable observation as Manitoba Hydro has made about any proposal made by an intervenor.

Q: Does Manitoba Hydro offer any reason not to pursue the allocation improvement you proposed?

A: In a sense. As it often does, Manitoba Hydro suggests that this improvement "needs to be considered in light of available resources, timing, and materiality of potential RCC changes." (Rebuttal at 30)

Q: What does Manitoba Hydro mean by considering an improved substation allocator "in light of available resources"?

A: Manitoba Hydro does not explain the nature of its concern. The type of analysis I described would require Manitoba Hydro to have an analyst spend a few hours manipulating the best available data in a spreadsheet.[14] Manitoba Hydro provided a simple improvement to the substation allocator in its rebuttal, so resources are clearly not a barrier to improving the allocation.

Q: What does Manitoba Hydro mean by considering an improved substation allocator "in light of timing"?

A: Again, Manitoba Hydro does not explain what it means. Manitoba Hydro has a history of delaying analyses beyond the date at which the results would be useful in upcoming cases. There is no excuse for delaying this analysis past the upcoming GRA.

Q: What does Manitoba Hydro mean by considering an improved substation allocator "in light of materiality of potential RCC changes"?

A: Manitoba Hydro seems to believe that the correction of the substation and demand-classified related distribution-line allocation would be immaterial. This position is belied by the example that Manitoba Hydro provides in Table 9 of the rebuttal, which shows an RCC improvement of 1.1% for the residential class and 2.8% for streetlighting, and RCC declines of 1.9% for GS Medium and 1.3% for GS Large <30 kV. These are not trivial changes.

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[14] Regardless of how the substation costs are allocated, Manitoba Hydro should automate data collection at its substations so that it knows the loads and load shapes on each substation. That process may take a while; as Manitoba Hydro acquires more data, it can improve the allocation.

The changes would be about 50% larger if Manitoba Hydro corrected its error of understating the demand-related portion of lines and wires, and included substation costs. Everything I say about the inadequacy of the NCP allocators for distribution substations applies even more strongly to the subtransmission lines, many of which serve multiple substations.

Q: Does the example Manitoba Hydro offers in Table 9 represent the best estimate available at this time?

A: No. While Manitoba Hydro says that "the 75/25 Winter/Summer CP allocator…would represent the most significant change in class RCCs that could be reasonably expected," an improved allocator for distribution demand may result in larger changes. Table 1 compares four potential substation allocators:[15]

- The distribution NCP allocator, which Manitoba Hydro used in PCOSS 2014 Amended.
- Manitoba Hydro's winter CP allocator, representing the top 50 hours of winter generation load.
- The allocator developed by Manitoba Hydro for its Rebuttal Table 9 (75% on the top 50 winter hours, 25% on the top 50 summer hours).
- An allocator that uses all the relevant data provided by Manitoba Hydro, starting with the class contribution to the monthly peaks. I weighted the seasons by the sum of peak loads for the substations peaking in each season (19.4% summer, 80.6% winter) and weighted the monthly load

[15] I included the SEP load in the allocators for GS Medium and GS Large <30kV.

within each season by the percentage of substations peaking in each month.[16] That computation is summarized in Table 2.

Table 1: Comparison of Diversified Substation Allocators

Class	NCP	Winter Top 50	Top 100 hours 75%W/25%S	Average of Dec–Feb CPs	Monthly CP Weighted by Substation Peaks
Residential	55.0%	51.3%	50.2%	51.1%	49.3%
GS Small Non Demand	9.8%	10.2%	10.4%	9.5%	10.1%
GS Small Demand	11.6%	12.0%	12.0%	11.6%	12.0%
GS Medium	15.8%	17.7%	18.3%	18.3%	18.8%
GS Large 750 V - 30 kV	7.9%	8.7%	9.1%	9.4%	9.7%

Table 2: Derivation of a Load-Based Substation Allocator

		GS Small				% of Peaks	
Month	**Res**	**Non-Dem**	**Demand**	**GSM**	**<30kV**	**Winter**	**Summer**
6	47.3%	10.6%	12.4%	19.5%	10.2%		3%
7	41.6%	11.9%	13.3%	21.5%	11.8%		25%
8	47.1%	9.4%	11.5%	20.7%	11.3%		27%
9	37.6%	12.5%	13.6%	23.8%	12.6%		27%
10	34.8%	12.0%	14.7%	24.9%	13.5%		
11	33.4%	12.3%	14.8%	25.6%	13.9%	3%	
12	48.0%	9.2%	12.0%	21.3%	12.1%	2%	
1	52.3%	9.6%	11.4%	17.7%	9.0%	50%	
2	53.1%	9.6%	11.5%	17.3%	8.5%	27%	
3	45.9%	11.6%	13.4%	19.4%	9.7%	16%	
4	53.2%	10.0%	11.3%	17.1%	8.4%	2%	
5	45.8%	8.4%	12.5%	21.3%	12.1%		17%
Weighted							
Winter	50.8%	10.0%	11.9%	18.2%	9.2%		
Summer	42.9%	10.7%	12.7%	21.8%	11.9%		
Annual	49.3%	10.1%	12.0%	18.9%	9.7%	19.4%	80.6%

[16] Manitoba Hydro did not provide the month of the peak load for substations in the Western Area or the Winnipeg suburbs in GAC/MH I-13, so the monthly weights are based on the distribution of peak loads on the Eastern, Northern and central Winnipeg substations. Manitoba Hydro provided the peak day for the Eastern and Northern substations and the date and time for the central Winnipeg substations, but I do not have class loads by date or time, other than the monthly peak.

Q: What do you conclude from this analysis?

A: I reach three conclusions. First, Manitoba Hydro is wrong that "the 75/25 Winter/Summer CP allocator…would represent the most significant change in class RCCs that could be reasonably expected." The reduction in the residential allocation from the NCP allocator to my load-based allocator is 20% greater than the reduction from NCP to Manitoba Hydro's 75/25 Winter/Summer CP allocator.

Second, Manitoba Hydro is wrong in concluding that the fact that most "distribution stations peak during one of the winter months" implies that correcting the allocation "may not yield results which are substantially different than using NCP." Manitoba Hydro's winter 50-CP allocator accounts for most of the change from the NCP allocator to the 75/25 allocator.

Third, even the one-hour winter CPs would allocate much less to the residential class and much more to the medium and large GS classes, compared to the NCP allocator.

Overall, this analysis indicates that the NCP allocator greatly overstates the responsibility of the residential class for substations (as well as subtransmission and feeders), and understates the responsibility of the GS Medium and Large classes. There is no reason to delay implementation of an improved allocator.

Q: Is your load-weighted substation allocator the best available allocator for substations?

A: Yes, at this time. For the upcoming GRA, and for subsequent GRAs, Manitoba Hydro may be able to further improve this allocator, using data on the hourly class peaks, as well as the date and time of substation peaks that it did not provide in discovery.

Q: What about allocating the costs of primary lines?

A: Until Manitoba Hydro can develop a better data-driven allocation, the PCOSS should use the substation-peak demand allocator (from Table 1) for poles and wires.

Q: How should subtransmission costs be allocated?

A: The logical and equitable approach is to allocate subtransmission with all transmission, on firm coincident peak. If the Board were to decide to exclude the GSL >100 kV class from the cost of the subtransmission, the appropriate allocator would be 100% of CP for the GSL 30kV–100kV class and 65% of CP for the distribution classes. Table 3 shows the results of this computation.

Table 3: Allocator for Subtransmission as a Separate Function

Class	NCP	Winter Top 50	Top 100 hours 75%W/25%S	Monthly CP Weighted by Substation Peaks, Dist at 65%
Residential	51.8%	40.8%	38.7%	43.0%
GS Small Non Demand	9.2%	8.1%	8.2%	8.9%
GS Small Demand	10.9%	9.5%	9.6%	10.9%
GS Medium	14.9%	14.1%	14.8%	17.7%
GS Large 750 V–30 kV	7.4%	6.9%	7.5%	9.2%
GS Large 30 kV–100 kV	5.7%	4.5%	4.6%	10.4%

B. Dividing Costs between Primary and Secondary Functions

Q: What other parties have provided evidence on the subfunctionalization of poles, wires and conduit between primary and secondary functions?

A: The only such evidence is from Mr. Harper, on behalf of the Coalition. At page 77 of his evidence, he expresses skepticism regarding the reliability of the subfunctionalization, which he dates to 1991.

In the next paragraph, Mr. Harper says that "The SCC data available from Manitoba Hydro's financial systems regarding Distribution Poles & Wires, Distribution Transformers, and Meter Investment and Maintenance is sufficiently detailed to facilitate sub-functionalization," which I originally read as describing the accounting data as supporting the primary-secondary split.

In the June workshop, Mr. Harper clarified that "I'm saying that in the context of substations versus poles and wires versus services" (June Transcript at 407).

His evidence thus supports mine. The primary-secondary subfunctionalization is both quite old and entirely undocumented, so the Board cannot determine whether the estimate was ever reasonable. My estimate of the secondary share of lines (20%, as opposed to the 30% in Amended PCOSS14) uses the limited data available from Manitoba Hydro and corrects the common error in the treatment of poles. This is the best estimate on the record and should be adopted by the Board, pending further data collection and analysis.

VII. Customer-Related Allocators

Q: What issues have arisen concerning Manitoba Hydro's allocation of customer costs?

A: The parties raised two issues. Mr. Harper notes that Amended PCOSS14 over-allocates service drops to residential, GSS and GSM customers (Coalition evidence at 79-80). Mr. Bowman contends that the large GS customers are allocated an excessive share of customer-service costs (MIPUG evidence at 37-39)

Q: Do these discussions change any of the positions you took in your initial evidence?

A: Yes. Mr. Harper's analysis, while imperfect, offers some ideas for improving the treatment of shared services in my initial evidence.

Mr. Bowman's arguments on the customer-service costs do not lead to any conclusions about the propriety of the cost allocations, but do highlight the inadequacy of Manitoba Hydro's documentation of customer-service costs for allocation purposes.

A. Allocation of Service Drops

Q: What problem did Mr. Harper find with Manitoba Hydro's allocation of service drops?

A: As I did in my initial evidence, Mr. Harper notes that the allocation fails to reflect the sharing of service drops. He estimates that there 103,000 residential customers and 4,900 GSS and GSM customers sharing 4,900 service drops.[17] By mistakenly assuming that every customer has its own service, the PCOSS over-allocates the cost of service drops to these smaller distribution customers.

Q: What change to the services allocator does Mr. Harper recommend?

A: In his evidence, he recommends crediting the three classes for the 103,000 non-existent services on a pro rata basis in proportion to class customer number.

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[17] Mr. Harper assumes that every building (and hence every service drop) includes a GSS or GSM account for the common space. This may not be true for small multifamily buildings, but some of larger buildings may have a second GS account (e.g., for a convenience store or a sandwich shop).

Q: Do you agree that Manitoba Hydro's allocator should be revised to reflect sharing of services?

A: Yes. However, Mr. Harper's proposal clearly skews the adjustment in favor of the GS customers. Under his proposal, the two classes would receive a reduction of 13,043 services even though there are only 4,900 GS customers sharing services (June Tr. at 415).

Q: How can Mr. Harper's calculation be improved?

A: As Mr. Harper agreed (June Tr. 418), his initial proposal could be corrected by spreading the credit for 103,000 non-existent services (the total number of residential customers and assumed GS customers, minus the number of buildings) in proportion to the total residential, GSS and GSM customers sharing the 4,900 services, rather than in proportion to the total customers in each of those classes. Manitoba Hydro should provide a breakdown of the GS customers in these buildings between GSS and GSM, so that the PCOSS can reflect shared services.

B. Allocation of Customer Service

Q: What change did Mr. Bowman recommend to Manitoba Hydro's allocation of customer service expenses?

A: Mr. Bowman argued that Manitoba Hydro allocated an excessive share of customer service costs to large General Service customers. He argued in particular that the Company did not substantiate the allocation of $1.2 million of "Customer Service (Other)" costs to industrials. (MIPUG evidence, 37–39). In his presentation, Mr. Bowman appeared to drop this recommendation for the current proceeding, while indicating that he intends to pursue it further in the future. (June Tr. 99).

Q: Do you agree that the opportunity to examine the allocation of customer service costs in this proceeding has been insufficient?

A: Yes. I am sympathetic to Mr. Bowman's complaint that Manitoba Hydro's documentation of customer service expenses lacked specificity. More generally, this proceeding has not provided enough of an opportunity to review customer costs in depth. These issues should be revisited in the next GRA or in another stakeholder consultation process.

Q: Are you convinced by Mr. Bowman's discussion that the GSL customers have been allocated excessive customer service costs?

A: No. This proceeding has not provided sufficient opportunity to examine Mr. Bowman's calculations or Manitoba Hydro's source data, particularly given his own statement that:

> 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. (Bowman at 38)

This lack of specific information prevents Mr. Bowman (and me) from assessing the validity of his specific complaint that the industrials are overcharged for:

> "costs related to line locates, safety watches, consumer consultations, building moves, and education/safety," [because] 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". (MIPUG evidence at 38)

Perhaps the industrials never need the line-locate service (which may have to do with finding underground lines to allow contractors to dig in the vicinity) or safety watches (which may have to do with guarding damaged equipment to allow it to continue operating safely) or consumer consultations (which may be meetings with large customers on supply plans, reliability and rate matters). Or maybe industrials use disproportionate amounts of some of these services. Perhaps the line locates, safety watches, and safety education are directed to protecting the transmission and distribution assets, and should be functionalized to those accounts.[18]

The Board should instruct Manitoba Hydro to provide more complete data and explanations for the customer service accounts and activities.

Q: Does this conclude your rebuttal evidence?

A: Yes.

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[18] It is also not clear what "house moves" are: moving distribution lines to allow buildings to be relocated, or administrative costs to track customers who are relocating.