Manitoba Hydro

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September 19, 2016

Mr. D. Christle
Secretary and Executive Director
Public Utilities Board
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

Dear Mr. Christle:

RE: MANITOBA HYDRO COST OF SERVICE STUDY METHODOLOGY REVIEW-CHRISTENSEN ASSOCIATES UNDERTAKING

On September 7th to 9th, the Public Utilities Board ("PUB") held oral public hearings with respect to the 2015 Cost of Service Methodology Review process. Manitoba Hydro is hereby providing the response prepared by its consultant Christensen Associates to the Undertaking requested by the PUB during the oral hearings at Transcript page 455.

Should you have any questions with respect to the forgoing, please do not hesitate to contact the writer at 204-360-3633 or Janelle Hammond at 204-360-4161.

Yours truly,

MANITOBA HYDRO LAW DIVISION
Per:

ODETTE FERNANDES
Legal Counsel

Att.

2015 COST OF SERVICE METHODOLOGY REVIEW

Manitoba Hydro Undertaking # 2

Christensen Associates to advise the Panel what it calculates or estimates the weighted energy allocator is actually doing in terms of classifying and allocating some costs by demand.

Response provided by Christensen Associates:

ALLOCATION METHODS: A CLARIFICATION

Demand and Energy Basis: Demand and Energy allocation, of costs of generation services, is based on output metrics including system peak demands (MW) and energy served (MWh). Longstanding and often used demand-energy methods include *system load factor*, *average and excess demand*, and *peak demands* without consideration of energy. The application of demand-energy methods varies with respect to the specification of peak demands: commonly applied definitions include one-hour maximum demand, observed coincident peak demands (e.g., fifty highest peak loads); one-hour coincident demands for each month of the peak season; and the weighted average of peak loads for summer and winter seasons.

Technology Cost Basis: Technology Cost allocation methods attribute generation technologies and associated costs to loads. Methods include *peak/shoulder/base*, *equivalent peaker*, and *production cost simulation*. Cost based methods draw upon the fixed and variable cost differences of technologies, and how/when the various technologies are used to produce energy. *Peak/shoulder/base* assigns technologies – and thus costs – to the corresponding peak/shoulder/base timeframes. *Equivalent peaker* simulates the implicit cost of peaking technologies (i.e. capacity costs), as a share of the total costs of base and intermediate technologies. The capacity cost share of total cost is assigned to peak loads; the residual share of total costs is allocated according to energy. *Production cost simulation* assigns the costs of specific technologies (and generating units) according to the simulated (or observed) hours/loads in which the various technologies (or generation units) which comprise the gen set were operating.

Economic Cost Basis: Marginal cost-based allocation has assumed an increasingly prominent place within the cost allocation toolbox. Two general approaches are available, including *internal marginal cost* and *opportunity cost*. The internal cost approach is based on the marginal or internal costs of energy and capacity of the service provider, while the opportunity cost method draws upon observed (or estimated) wholesale market prices for generation services.

DEMAND SHARE WITHIN MANITOBA HYDRO'S WEIGHTED ENERGY ALLOCATOR:

Manitoba Hydro's (MH) weighted energy allocator, including capacity costs, is an opportunity cost methodology where, to a large extent, the marginal energy cost component is based on the observed market value of energy ($/MWh) observed within the generation market organized by the Mid-Continent Independent System Operator (MISO). Loads of the various domestic classes served by MH are weighted by time period-specific marginal costs. Economic costs generally follow loads: higher costs are associated with higher loads – thus the demand-related impacts of total costs inherent to marginal cost-based allocation. In this respect, marginal cost allocation results tend to parallel Demand and Energy based methods briefly discussed above, though significant different allocation results can be obtained.

Shown below in Table 1 (marginal energy costs) are the demand-attributed cost impacts implicit within MH's weighted energy, for *energy costs only*.

TABLE 1[1]

Marginal Energy Cost

	Peak	Off-Peak	Average
Spring	53.00	35.72	39.78
Summer	66.00	30.93	39.17
Fall	56.00	35.72	40.49
Winter	67.00	42.76	48.50
Average	62.50	36.45	42.59

Peak Period Demand Factor, Energy Cost Basis

Peak-Off Peak	1.71	**Peak-Average**	1.47

Peak Period Demand-Related Cost (Peak-Average)

$/MW-Year	41,104
% of Total	11%

Table 2 (marginal energy and capacity costs) presents demand-attributed cost impacts implicit MH's weighted energy methodology, inclusive of *both energy and capacity costs*.[2]

TABLE 2[1]

Marginal Costs, with Energy and Capacity*

	Peak	Off-Peak	Average
Spring	71.90	35.72	44.22
Summer	84.90	30.93	43.61
Fall	74.90	35.72	44.93
Winter	85.90	42.76	52.98
Average	81.40	36.45	47.04

Peak Period Demand Factor, Energy/Capacity Cost Basis

Peak-Off Peak	2.23	**Peak-Average**	1.73

Peak Period Demand-Related Cost (Peak-Average)

$/MW-Year	70,922
% of Total	17%

* Set at equivalent cost level across all peak period hours.

[1] The *$/MW-Year* amounts shown in Tables 1 and 2 are equal to the difference between peak period and average marginal costs, multiplied by the peak hours. These amounts are ($62.50 – $42.59)*2,064 = $41,104 and ($81.40 – $47.04)*2,064 = $70,922 for Tables 1 and 2, respectively. The *Percent of Total* percentages are equal to $/MW-Year$_{\text{Peak Period}}$ divided by the $/MW-Year$_{\text{Annual Total}}$. These percentages are $41,104/$373,048 = 11% and $70,922/$412,058 = 17%, also for Tables 1 and 2 respectively.

[2] The $/kW-year value of capacity, used by Manitoba Hydro within its Weighted Energy allocation methodology, generally approximates the market value of capacity, as recently obtained in viable capacity auctions of RTOs/ISOs of the Eastern Interconnection, in recent years. Nonetheless, variation in capacity auction prices is substantial and highly specific to timeframe and auction design.

The notion of demand attribution within marginal costs and marginal-cost based allocation is a matter of definition; other plausible interpretations are available.