Daymark Follow Up Questions for May Workshop

Requests for Documents

1) Please provide the following in native electronic excel format. These refer to IR responses MH provided in this proceeding.
   a. Attachment to PUB-5
   b. Attachment to COALITION 34c
   c. Tables and charts in response to PUB 20, PUB 21, PUB 22, PUB 26, PUB 30c, PUB 31, PUB 34, PUB 37b, PUB 60d, PUB 65, PUB 70, PUB 71, PUB 73, MIPUG 4, MIPUG 6a, MIPUG 10, MIPUG 17, & COW 3

2) The attachment to the response to PUB 53 has hourly load profiles for different domestic classes, please also provide the same hourly load profile data for the following in the same excel format, to the extent available:
   a. Exports
   b. Common Bus Load
   c. Wind Generation
   d. Imports
   e. Generation
   f. Station Service

3) The attachment to the response to PUB 53 has hourly load profiles for different domestic classes, please also provide the following for each of the years provided in excel format, to the extent available:
   a. Times of the top 50 summer hours
   b. Times of the top 50 winter hours

4) Please provide any supporting calculations available for developing the C40 and C41 allocators. Please provide them in Excel format.

5) If possible please provide an excel spreadsheet with data for all cost centers from SAP that were used in the PCOSS 14 Amended model? Please show data for each individual cost center.

6) Refer to the response to PUB 45: Please provide actual amount of dollars of operating and depreciation expense functionalized on the 36%/28%/36% basis for system control costs.

7) Refer to the response to GAC 45: If possible, please provide the average number of customers/transformer for each rate class.

8) Please add firm sales volumes to the table to the response to PUB 22b.

9) Please add the sales under the WPS contract under permit 379 to the table in the response to PUB 22d.

10) Please provide MH's most recent forecast of monthly and annual prices for sales into the MISO day ahead and real time markets in Microsoft Excel format.

11) For each generating unit at each hydro station please provide the daily generation output from the past 15 years in Microsoft Excel format.

12) Refer to the response to Coalition 47:
    a. Please provide the planning studies related to Riel Station
    b. What portion of the cost of the original Riel Reliability Project was done specifically to accommodate Bipole III? What is this in dollars? Would it be included in the portion of costs functionalized as generation?

13) Refer to the response to Coalition 44:
    a. Please provide all planning studies related to Bipole III that includes a system assessment based on Manitoba system reliability criteria.
    b. Bipole III rating was increased from 2000 MW to 2300 MW. If there were any studies performed to support this change, please provide them.

14) To clarify the request in PUB/MH I-22(c), please provide the table of MISO sales by dollars ($M) and by volume (GWh).

15) Please refer to PUB/MH I-20 and I-21: If MH has completed any load flow studies based on actual hourly system data, please file them.

Discussion Questions

16) Please refer to the estimates of export kWh reported in Schedules D1 and D2 of PCOSS 14 Amended
    a. Why are total annual exports different in each schedule?
    b. How are total exports estimated?
    c. How is surplus dependable energy estimated?
    d. The percentages of power to each of the twelve time periods and the summer and winter periods are the same. Is sales volume data available for firm sales and MISO sales on monthly or hourly basis? Could that be used to analyze whether the assumption of the same value is reasonable?
    e. For the calculation of the 2CP allocator, are the allocations of energy to winter and summer periods based on eight years of data or just one?

17) Please refer to the response to PUB 43: MH discusses excluding costs beyond point of service from the allocation of NER. Lighting class is largely unmetered. Why should metering costs be included in the NER allocator as prior to the point of service?

18) Refer to the response to Coalition 16e: Does MH propose to change its methodology and include NEB fees in the generation pool instead of assigning them to the export class?

19) Refer to the response to PUB 45: Why is MH using this functionalization instead of just a simple one third weighting?

20) Can MH make a firm commitment to updating allocator studies instead of just saying "as resources are available"?

21) How when will load research be updated to reflect the operation of Keeyask? Is there any time when MH will have to use load research without Keeyask to develop allocators for a PCOSS model that includes the costs of Keeyask? If so, how does MH intend to address this?

22) How is transmission designed to support new hydro? What hydraulic conditions does MH consider? How does it impact the sizing of the lines and their cost?

23) How are opportunity sales opportunities considered in transmission planning?

24) Is the split between tariffable and non-tariffable transmission assets something MH is considering using to refine its cost allocation methodology? How? Would it rely on the 7 factor test as a kind of cost causation principle?

25) Refer to the response to Coalition 44:
   f. What does MH mean by increased reliability? Is it related to reserves, meeting peak demand, or something else?
   g. Bipole III rating was increased from 2000 MW to 2300 MW. When was this change made and why? Does it relate to the planned construction of Conawapa?

26) Is there any plan to allocate the costs of ancillary services any differently than using the 2CP allocator? If so, what is MH considering?

27) For the US interconnection, both existing and planned new one, what are the line ratings and how were they sized? Are they sized to meet peak demand for peak export periods?

28) When do peak flows generally occur for the Bipoles? Does this vary from peaks on the AC transmission system?

29) What were the changes to the revised model provided on April 25? Was it only a change to the weightings for the weighted energy allocators?

30) Why is the line to Churchill functionalized as transmission and the Bipoles as generation when they both connect remote generation to load and have unidirectional flows?

31) MH is able to firm up sales one year in advance once hydro conditions are known. Why shouldn't these firm sales attract generation and transmission fixed costs just like surplus dependable energy?

32) Why is the revenue requirement for Bipole III and Riel shown in row 109 of the Allocated Costs page of the model provided as attachment 1 to the response to PUB 55 different from that shown on page 7 of the response to PUB 70?

33) Question for Christensen Associates:
   h. How are generation costs usually allocated to interruptible customers?
   i. How are off-system sales revenues typically allocated to customer classes?

34) From MH: "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."
At current export market prices and resulting revenues, does the situation still exist that incorporating these export revenues in the COSS without an export class (that is, allocating export revenues on a G&T basis) would result in unfair class revenue requirements? Would the resulting rates in some customer classes drop below the marginal cost?

35) Please reconcile the responses to PUB/MH I-2 and PUB/MH I-13(d) with the Provincial Government's March 3, 2000 press release announcing the construction of the Brandon combustion turbines. Specifically, please reconcile the purpose of the combustion turbines as a benefit to export sales, and why it is not appropriate to directly assign the fixed costs to the export class.
http://news.gov.mb.ca/news/index.html?item=24387&posted=2000-03-03

36) If the Brandon CTs were no longer available, please explain whether there would be reduced firm export sales from Keeyask (as Keeyask would be needed to serve domestic load). In responding to this question, please consider multiple

timeframes such as when Keeyask first enters service and at a time when Keeyask services domestic load.

37)PUB/MH I-23(c) states that Lower Nelson energy in excess of dependable hydraulic energy can displace other dependable resources (e.g. thermal) as opposed to being sold as opportunity exports. Does this suggest that dependable sales can be made from this excess energy?

38)Does the response to PUB/MH I-13(e) mean that, upon expiration of Manitoba Hydro's legacy export contracts, firm export sales will be capped at the prevailing surplus dependable energy from Keeyask or future hydroelectric generating stations?

Additional Questions for Manitoba Hydro

39) PUB/MH I-10 (b)

a) The question was in the context of the COSS not financial report. What is meant by costing purpose? How do other jurisdictions treat opportunity exports in a COSS?

b) Does any other jurisdiction have a similar distinction between dependable and opportunity in the cost of service?

40) PUB/MH I-13(a-b) MISO Reserve

Please explain whether the MISO-MH reserve of 200 MW is included in the above 12% reserve and explain why MH holds 150 MW of hydraulic generation in a standby role. Is this a direct cost for firm exports?

41) PUB/MH I-12(d)

a) Please explain how MH's capacity reserve typically (in non-drought years) translates into additional opportunity sales.

b) Please explain what MH's capacity surplus would exist if thermal generation was closed.

c) Can peak(5x16) opportunity sales occur if MH has no capacity surplus?

d) Are MH's firm or opportunity sales constrained if Bipole III doesn't exist? Please quantify the firm or opportunity sale amount.

42) PUB/MH I-13(e)

Please explain which non-hydraulic resources go to meeting the 12% domestic load capacity of 600MW±:

- Brandon Coal 105MW?
- Brandon SCCT(s) 275 MW?
- Natural Gas? 132MW?
- Diversity Purchases 550 MW?

43) PUB/MH I-13 Expanded US intertie

a) Without an expanded intertie how much would MISO firm export sales be reduced and how much would MISO opportunity export sales be reduced over the next 20 years?

b) Provide a 20 year PRP and IFF to illustrate these impacts.

44) PUB/MH I-14 -Trading Desk Costs allocated to Net Exports

There has been no analysis since 2009.

a) Has MH's Trading Desk organization structure changed since then? How?

b) How would market changes since 2009 alter the allocation of costs to the export class?

c) For the last ten years define the hydro generation (on a monthly basis), where trading desk activities were primarily required for export or imports for domestic reliability?

d) What is the relative value per KWh of exports and imports during the ten years?

e) Was the original intent of joining MISO related to reliability or exports or both?

f) To what extent do export activities facilitate the need for import activities in MH's servicing of the export market? If MH did not export any power, would MH require any imports?

45) PUB/MH I-29(a) & (b)

a) Please indicate the impact on generation capacity of Keeyask based on the removal of 1 installed unit (generator and turbines).

b) Please provide an updated power resource plan table reflecting the above based on the 2015 Load forecast.

46) PUB/MH I-55 Bipole III

a) How much incremental export sales (broken down by firm and opportunity sales in GWh) would be achieved with Bipole III?

b) Please provide a 20 year PRP and IFF to illustrate these impacts.

47) PUB/MH I-63 (b)

The Cost analysis provided excluded indirect costs

a) Please update the table to include full costs of Wuskwatim, Point du Bois and Keeyask.

b) For the above table please indicate the order of magnitude of the % of indirect costs associated with the overall average cost in column 8.

48) PUB/MH I-68 (b)

Allocation of HVDC Costs – Demand vs. Energy.

a) Please refile the table analysis assuming that Bipole III and the Riel were in-service. Please also confirm that Dorsey is included in the analysis.

b) Please provide the same analysis in (a) based on 1 CP, only using winter peak.

c) Please provide the same analysis (a) & (b) assuming 25% of the HVDC costs are allocated to demand.