May 1, 2014

Supplementary Pre-Filed Testimony of P. Bowman

During the course of the NFAT Review hearing Manitoba Hydro has recently provided updated economic and financial analysis in a series of exhibits marked MH-104.

The attached supplements the Revised Pre-Filed Testimony of P. Bowman in Regards to the Manitoba Hydro Needs For and Alternatives To (NFAT) Business Case, filed as Exhibit MIPUG-9-2, for the financial and economic analysis portions of the evidence.

Section 1.0 reviews the updated Economic and DSM Analysis.

Section 2.0 reviews the updated Financial Analysis and Load Forecasts.

It is noted that to date the response to PUB/MIPUG I-13 remains unanswered. Due to updates to the DSM scenarios since the information was requested, the IR is answered within Section 1.0 of this filing.

1.0 Supplementary Pre-Filed Testimony of P. Bowman – Updated Economic Analysis

The updated economic analysis relied on data provided by Manitoba Hydro in the MH-104 exhibits. The analysis done compared between the different levels of DSM for the scenarios provided.

Economic Analysis Update (MH-104)

The updated economic analysis provided has the following perspectives and limitations:

- Scenarios with “no DSM” were not provided, which is a limiting factor in the analysis.
- The economics sheets allow for two important comparisons: Customer Perspective, and Manitoba Hydro perspective.

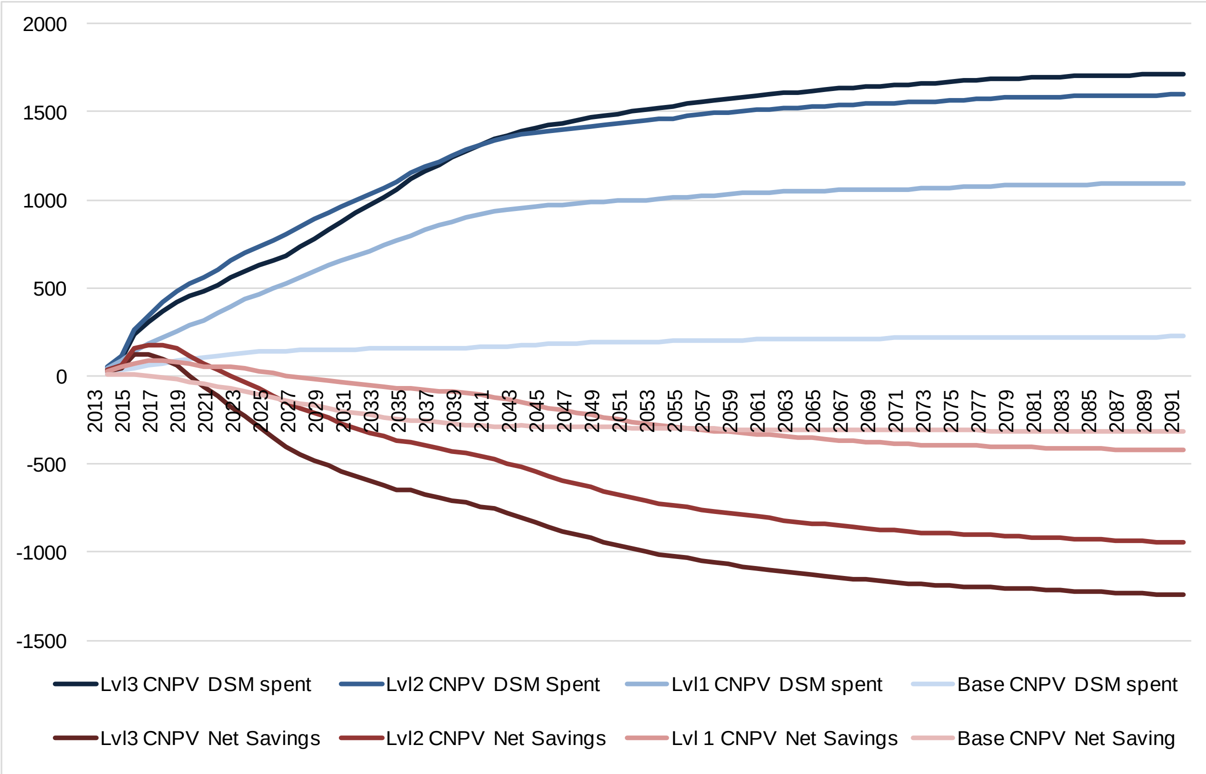
Updated Economic Analysis - Customer Perspective

For customers, the “Total Resource Cost (TRC) version” (which includes ALL DSM spending - both customer and Hydro, and does not reflect domestic revenue lost) was compared with the “Manitoba Hydro (MH) version” (which includes only MH DSM spending not the customers, and does reflect revenue loss).

- From this, the TRC version was subtracted from the MH version to tell whether the DSM is economic for the customers in total. Since it includes ALL customer DSM spending, and ALL customer bill savings, it actually can assess whether the Base DSM level is economic for all domestic customers, as well as at each progressive DSM level. NOTE: This can show whether DSM is good for customers as a group, but not that it is good for the customer participating versus non-participants, etc.
- It is unknown what Manitoba Hydro used to estimate the domestic revenue impact. For this analysis it is surmised that consistent assumptions on revenue were used (with a consistent underlying rate assumption – not different rates in each scenario).
- This can be compared year by year, to see the pattern of returns.

Figure 1 below compares the customer perspective on DSM savings, which is similar for all Plans.

Figure 1: Customer Perspective on DSM Spending Cost vs. Net Savings ($ Millions NPV) - All Plans



In the above chart, the increasing levels of DSM are shown with increasing dark colors. Base DSM (lightest color) takes customer spending that works its way up to approximately $200 million NPV (the lightest blue line), and savings that eventually are on the order of $500 million NPV, to yield about $300 million in Net Savings (the lightest red line).

Moving to Level 1 DSM (the next darkest) adds a huge amount of extra cost, with only enough extra benefits to end up very close to the Base DSM base (about $300 million NPV Net Savings).

Level 2 DSM is a fair bit more costly again for customers, but this time with substantial Net Benefits of about $1 billion NPV.

Even Level 3 DSM (the darkest line), which costs only slightly more than Level 2, is better for customers than Level 2 DSM. Note that the way Hydro has designed the programs, the extra Level 3 initiatives cost customers almost nothing.

As customers are likely most focused on cash flow and not economic/financial considerations, the above is a fairly good representation of how customers collectively might look at DSM opportunity (i.e., no need to look at financials to learn more).

Updated Economic Analysis - Manitoba Hydro Perspective

For the Hydro perspective, the picture is somewhat more complicated:

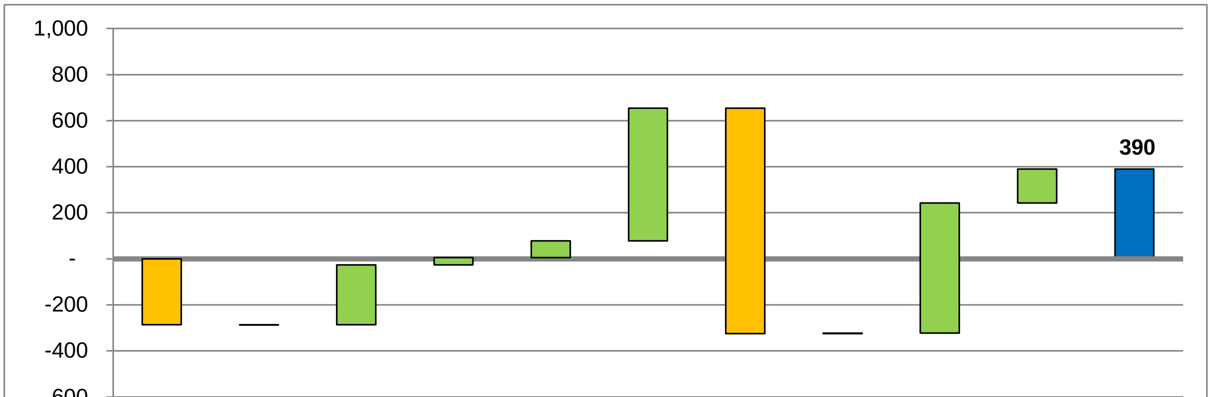
- First, it can't be determined whether or not Base DSM is economic, as a "No DSM" case was not provided.

- Second, there are a lot more moving variables to track that have an effect on the economics for Manitoba Hydro– DSM can lead to more exports, less purchases, changed development sequences and timing, plant deferral, etc.

Plan 5 (K19/Gas/750MW) DSM Level Comparison

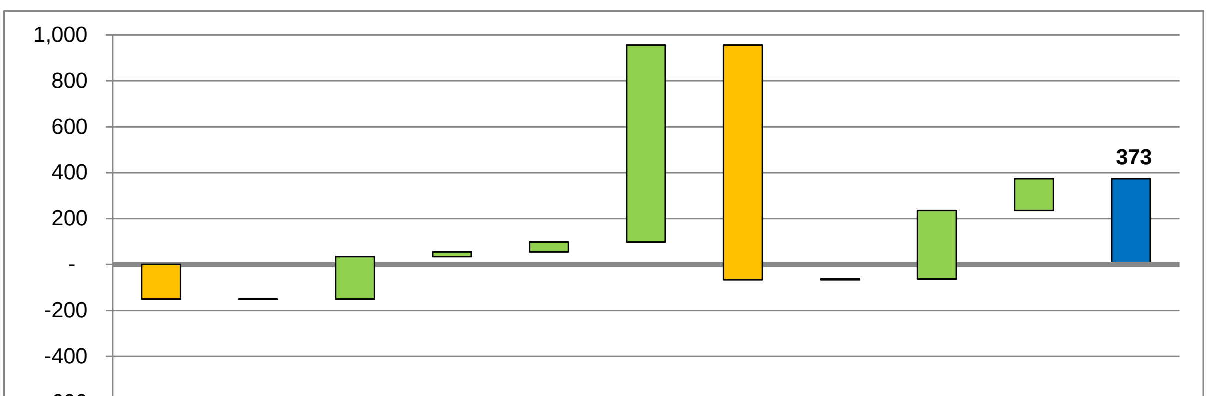
Each variable is tracked in the Figures below comparing each level of DSM for Plan 5 (K19/Gas/750MW). Plan 5 was chosen as it is the middle case for capital development between Plan 1 (All Gas) and Plan 14 (PDP).

Figure 2: PLAN 5 (K19/Gas/750MW) – Benefits of DSM Level 1 Over Base – MH perspective over 78 Years ($ Millions NPV)



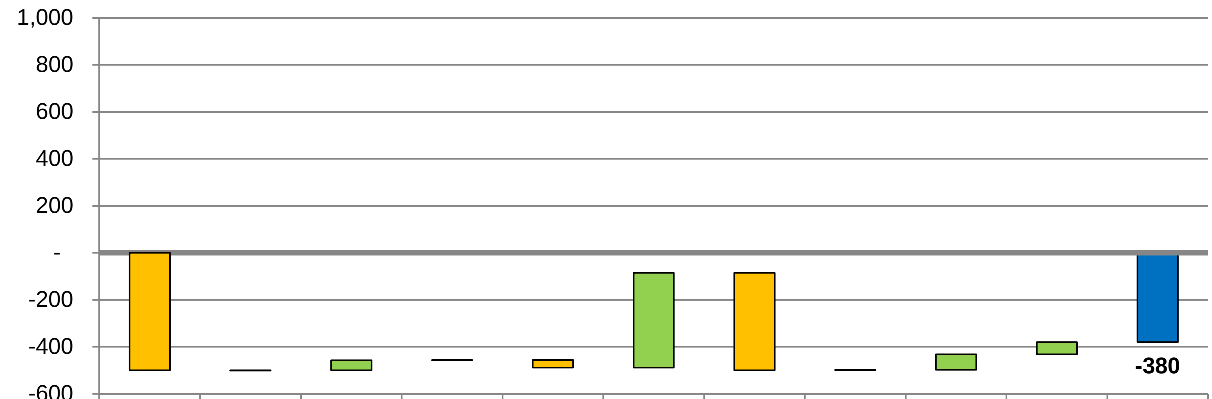
	Spend DSM	Defer Hydraulic/US Trans	Defer Thermal	Defer GOT	Less Cap Tax/ Fixed O&M	Extra Exports	Lost Dom Revenue	Less Water Rentals	Less Thermal Fuel	Less Purchased Power	Net Benefit
ends											390
before	-	-287	-287	-26	6	77	654	-324	-322	242	
after	-287	-287	-26	6	77	654	-324	-322	242	390	

Figure 3: PLAN 5 (K19/Gas/750MW) – Benefits of DSM Level 2 Over Level 1 – MH perspective over 78 Years ($ Millions NPV)



	Spend DSM	Defer Hydraulic/US Trans	Defer Thermal	Defer GOT	Less Cap Tax/ Fixed O&M	Extra Exports	Lost Dom Revenue	Less Water Rentals	Less Thermal Fuel	Less Purchased Power	Net Benefit
ends											373
before	-	-151	-151	35	55	98	956	-66	-63	235	
after	-151	-151	35	55	98	956	-66	-63	235	373	

Figure 4: PLAN 5 (K19/Gas/750MW) – Benefits of DSM Level 3 Over Level 2 – MH perspective over 78 Years ($ Millions NPV)



	Spend DSM	Defer Hydraulic/US Trans	Defer Thermal	Defer GOT	Less Cap Tax/ Fixed O&M	Extra Exports	Lost Dom Revenue	Less Water Rentals	Less Thermal Fuel	Less Purchased Power	Net Benefit
ends											-380
before	-	-500	-500	-457	-456	-488	-85	-500	-498	-432	
after	-500	-500	-457	-456	-488	-85	-500	-498	-432	-380	

As shown in Figure 2, Level 1 DSM is relatively high cost to Hydro ($287 million NPV) but provides overall net benefits of $390 million NPV. The most substantial benefits are extra exports and reduced use of thermal fuel, as well as some deferral of thermal generation. The largest downside is lost domestic revenue, highlighting the importance of focusing on lost revenue when assessing DSM (including via the RIM or PACT tests).

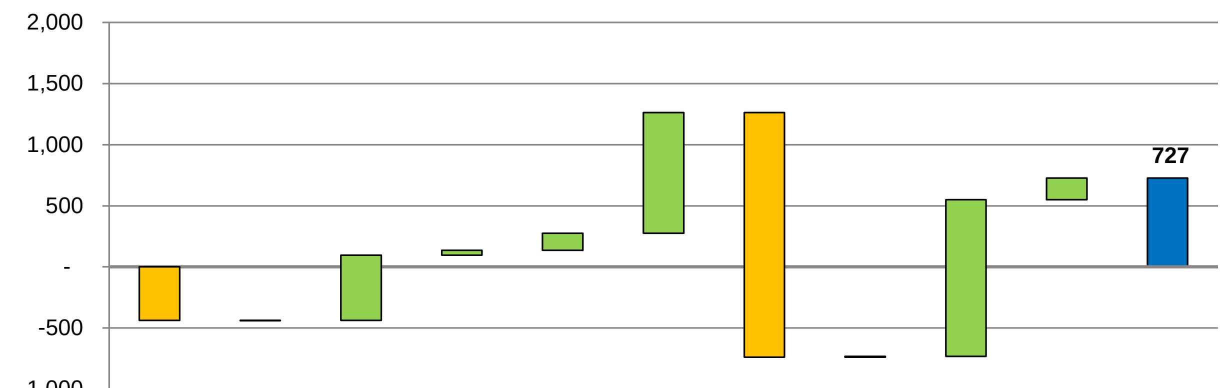
Figure 3 above shows the relatively low extra cost of Level 2 DSM ($151 million NPV) with very substantial added net benefits ($373 million NPV over and above the Level 1 NPV), largely due to added exports.

Figure 4 above illustrates the issues with Level 3 DSM. The high level of cost is noted ($500 million NPV) with limited energy saved (shown by smaller domestic revenue savings that the previous levels). In short, Level 3 DSM is excessively compensated to the customer for the benefits returned to Hydro (-$380 million NPV).

All Plans DSM Comparison of Level 2 DSM to Base DSM

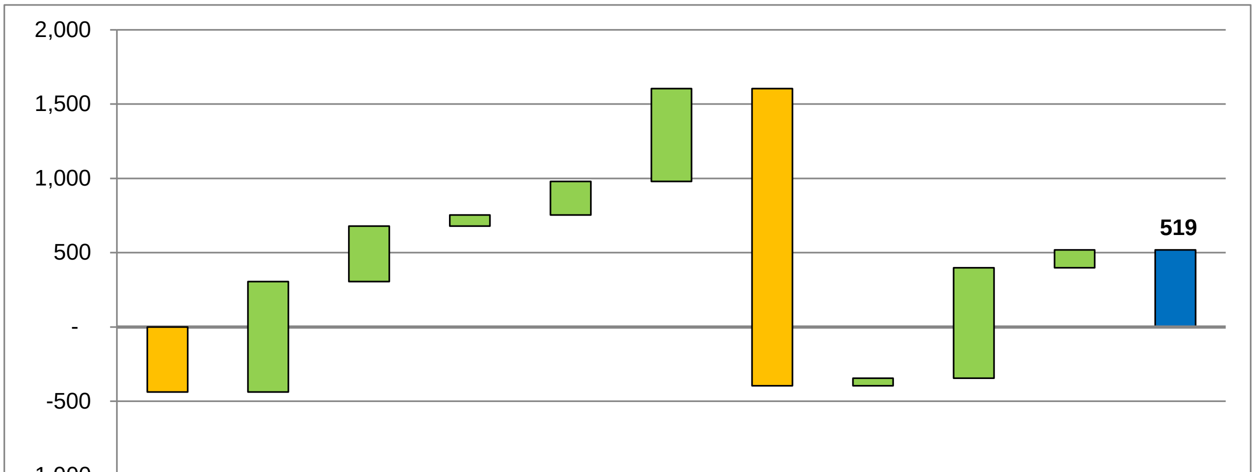
Similarly, the differential performance of Level 2 DSM (compared to the Base DSM case) was tracked in the main plans that have been fully and consistently updated to date (Plans 1, 2, 5 and 14).

Figure 5: Plan 1 (All Gas) - Net Benefits of DSM Level 2 Over Base DSM – MH perspective over 78 Years ($ Millions NPV)



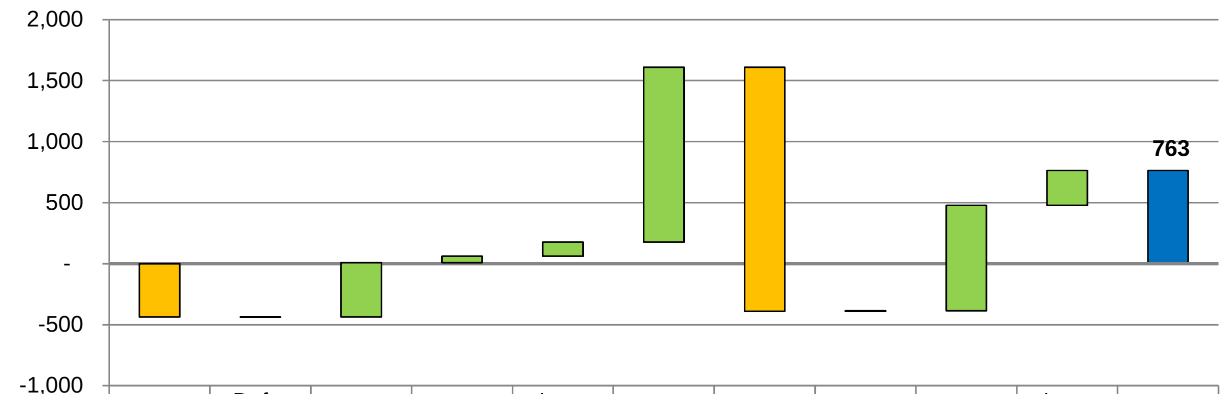
	Spend DSM	Defer Hydrauli c/US Trans	Defer Thermal	Defer GOT	Less Cap Tax/ Fixed O&M	Extra Exports	Lost Dom Revenue	Less Water Rentals	Less Thermal Fuel	Less Purchas ed Power	Net Benefit
ends											727
before	-	-437	-437	97	137	275	1,263	-739	-732	551	
after	-437	-437	97	137	275	1,263	-739	-732	551	727	

Figure 6: Plan 2 (K/Gas) – Net Benefits of DSM Level 2 Over Base DSM – MH perspective over 78 Years ($ Millions NPV)



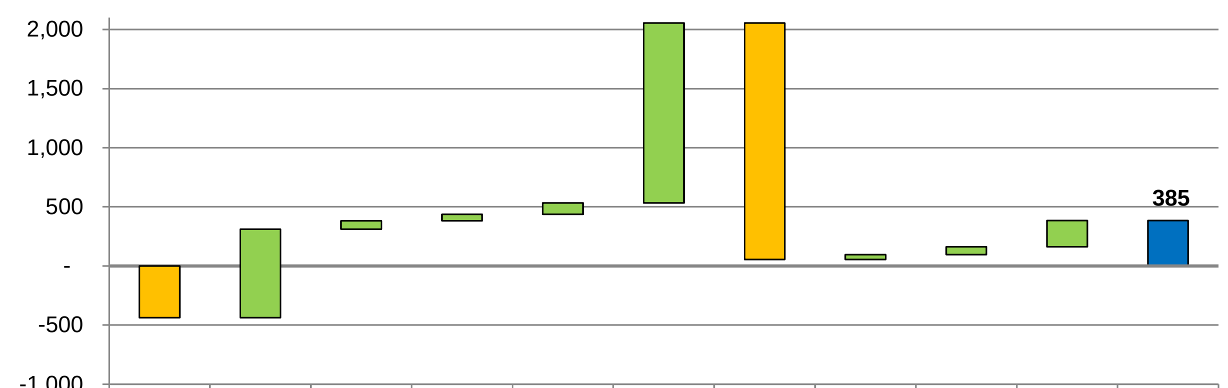
	Spend DSM	Defer Hydrauli c/US Trans	Defer Thermal	Defer GOT	Less Cap Tax/ Fixed O&M	Extra Exports	Lost Dom Revenue	Less Water Rentals	Less Thermal Fuel	Less Purchas ed Power	Net Benefit
ends											519
before	-	-437	306	679	754	980	1,605	-397	-344	398	
after	-437	306	679	754	980	1,605	-397	-344	398	519	

Figure 7: Plan 5 (K19/Gas/750MW) – Net Benefits of DSM Level 2 Over Base DSM – MH perspective over 78 Years ($ Millions NPV)



	Spend DSM	Defer Hydraulic/US Trans	Defer Thermal	Defer GOT	Less Cap Tax/ Fixed O&M	Extra Exports	Lost Dom Revenue	Less Water Rentals	Less Thermal Fuel	Less Purchased Power	Net Benefit
ends											763
before	-	-437	-437	8	61	176	1,610	-391	-386	478	
after	-437	-437	8	61	176	1,610	-391	-386	478	763	

Figure 8: Plan 14 (PDP) – Net Benefits of DSM Level 2 Over Base DSM – MH perspective over 78 Years ($ Millions NPV)



	Spend DSM	Defer Hydraulic/US Trans	Defer Thermal	Defer GOT	Less Cap Tax/ Fixed O&M	Extra Exports	Lost Dom Revenue	Less Water Rentals	Less Thermal Fuel	Less Purchased Power	Net Benefit
ends											385
before	-	-437	311	382	438	533	2,055	54	96	163	
after	-437	311	382	438	533	2,055	54	96	163	385	

The above graphs show the progression related to excess spending for Level 2 DSM ($437 million for each plan) over Base DSM compared to the net benefits after all other variables are taken into account. For Plan 1 (All Gas) the net benefit over the 78 year planning horizon is $727 million NPV (Hydro investment, not counting the customer investment). For Plan 2 (K/Gas) the net benefit is $519 million NPV. Plan 5 (K19/Gas/750MW) has the highest net benefit of $763 million NPV and Plan 14 (PDP) has the lowest net benefit of $385 million NPV.

The mix of benefits from the DSM is notably different in the four cases, comprised of mostly extra exports in Plan 14 (PDP), compared to more of a mix of benefits from capital deferral and saved fuel in the smaller plans.

What Does the updated Economic and DSM Analysis Conclude?

1) Every plan economically benefits from adding DSM up to Level 2 DSM.
2) Some plans benefit more from DSM. In general, the more “saturated” the provincial grid is under a given plan (i.e., the more hydro generation is added relative to the size of Interconnection added) the less the DSM will be of benefit and vice versa. Largest DSM benefits are under Plan 1 (All Gas) and Plan 5 (K19/Gas/750MW); least benefits under Plan 2 (K/Gas) and Plan 14 (PDP).
3) The pipeline scenarios are not included in this analysis.
4) The largest factor of concern in DSM scenarios is the lost domestic revenue. This underlines the importance of continuing to track this impact on Hydro and non-participating customers through variables such as the RIM and PACT tests.
5) Level 3 DSM is poorly designed – entirely mismatches costs (far too much to Hydro) and benefits (entirely to the customer). However, even if combined (TRC view) it is still not economic. Underlines that it is not just TRC that matters, but also distributional aspects.

2.0 Supplementary Pre-Filed Testimony of P. Bowman – Updated Financial Analysis

The updated financial analysis relied on data provided by Manitoba Hydro in MH-104-12-4, comparing with the original financial data filed with the NFAT Business Case, Appendix 11.4.

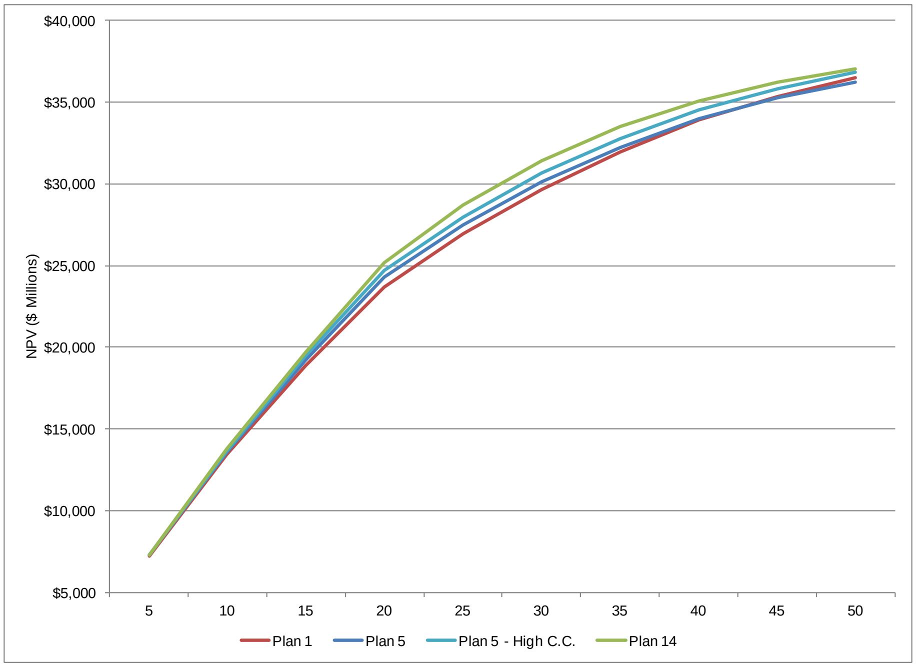
Financial Analysis Update (MH-104-12-4)

The updated financial analysis provided by Manitoba Hydro in MH-104-12-4 used the following assumptions:

- Based on a 2012 forecast updated for 2013 load forecast (Appendix D), 2013/14 electricity and natural gas price forecasts, May 2013 economic indicators and March 2014 capital cost updates for Keeyask and Conawapa. This includes updates explained in Appendix 9.3, pages 12-14:
    - On-peak export energy price forecast increased by 7% from the 2012/13 forecast
    - Natural gas price forecast on average decreased by 6% relative to the 2012/13 forecast
    - The 2013/14 Domestic Load Forecast (including base DSM) has decreased from the 2012/13 Domestic Load Forecast (with Base DSM). Note: For InterGroup's financial analysis with unit costs, the load forecast used was held constant after 2047/48.
- Updates were not made for actual 2013 results or the 2013 base capital spending (common to all development plans) as Hydro indicates that the 2013 financial model has not been extended for the 50-year study period.
- In terms of the Keeyask and Conawapa capital costs, both the reference and high capital cost scenarios are provided. MH's best guess or most likely capital costs are in the reference scenario.

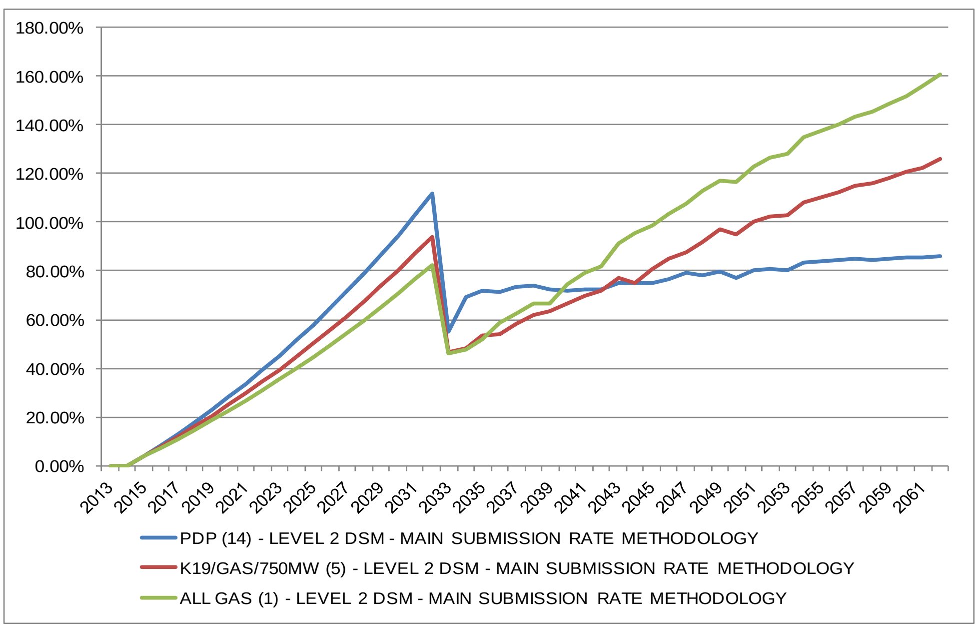
Figure 1 below shows the total updated amounts to be paid by ratepayers in rates for each Plan for Level 2 DSM under the main submission methodology, i.e. the scenario corresponding with the original financial analysis (with rates set to reach a 75:25 debt-equity ratio by 2031/32 and thereafter maintaining a 1.20 interest coverage ratio). The high capital cost scenario for Plan 14 is not graphed as Manitoba Hydro has said if Keeyask was built under high capital cost conditions and these conditions were expected to continue Conawapa would not proceed (essentially converting the resource plans to Plan 5).

Figure 1: NPV Total Amount Paid in Rates ($Millions) for Level 2 DSM – Main Submission Methodology



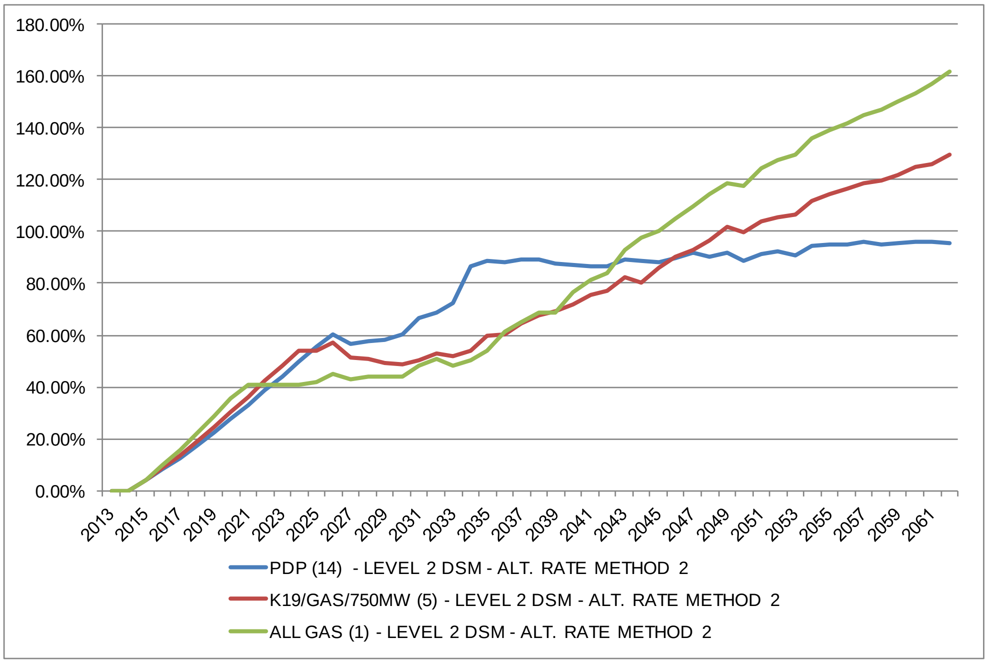
The cumulative rate impacts associated with the main submission methodology are provided in Figure 2 below and continue to show a large drop-off in the rates paid after reaching the 75:25 debt-equity ratio in 2031/32.

Figure 2: Comparison of Cumulative Rate Increases – Main Submission Methodology



As an alternative, Manitoba Hydro has provided Alternative Rate Methodology #2 which serves to smooth the erratic rate adjustments in the years immediately after 2031/32 while minimizing net losses in the first ten years[1]. As seen in Figure 3 below, this methodology leads to higher results in years 2013 to 2024 (approximately) for Plan 1 (All Gas) and Plan 5 (K19/Gas/750MW) compared with Plan 14 (PDP), which are skewed by the treatment of sunk costs. After this window, this approach leads to lower rate increases for Plan 1 (All Gas) until around 2041 and until around 2047 for Plan 5 (K19/Gas/750MW) when compared to Plan 14 (PDP). In short, the alternative rate method mostly serves to defer the adverse impacts of Plan 14 (PDP) by way of taking a far more relaxed view of Hydro's financial targets for the first one to two decades.

Figure 3: Comparison of Cumulative Rate Increases Using Alternative Rate Methodology #2 and Reference Capital Costs



Comparison to the Original Financial Analysis

The financial analysis update provides different revenue scenarios given changes in the load forecast due to forecast levels of DSM reached by domestic customers. This provides a challenge in comparing the updated analysis to the original, as changes in domestic revenues are a result of both changes in rate increases and changes in the amount of energy consumed by domestic customers (i.e. quantity of energy).

- Therefore, for this analysis, different units were used than the original analysis to isolate the total domestic revenue on a unit levelized basis (cents/kW.h levelized). The below figures use the Levelized cost of energy (cents/kW.h) in real terms. This analysis provides graphs that correspond with those shown in Appendix C of P. Bowman's pre-filed testimony[2], only with a different presentation of units.

Financial Update Methodology

New updated pro forma financial statements were provided in MH-104-12-1, MH-104-12-2 and MH-104-12-3 for. The following was provided:

- Plans 1, 5 and 14 in the ref-ref-ref scenario

[1] Explained in MH-104-12 Overview for April 11, 2014 Filing of the DSM Financial Evaluation, page 2
[2] MIPUG-9-2, Appendix C, Starting in section 4.1: Ratepayer impacts under the full range of scenarios

- Four DSM scenarios for each ref-ref-ref plan (base, Level 1, Level 2 and Level 3)
- High capital cost scenarios for Plans 5 and 14 (High Keeyask costs for Plan 5 and high Keeyask and Conawapa costs for Plan 14, no scenario for Plan 1).

Since the load forecast was changed (provided in MH-104-3) calculating the total PV of ratepayer costs (as was done in MIPUG-9-2, Bowman's Pre-Filed Testimony) was no longer a proper comparison from the original filing as decreases to load would show as decrease to ratepayer costs, which is potentially misleading. Therefore, the unit cost calculation approach was taken for comparison purposes. This was done as follows:

- **Numerator:** The present value of revenues (General Consumers Revenue at approved rates and Additional General Consumers Revenue) was present valued using the same 5.05% real discount rate. Note that the updated 2% inflation rate was used to be consistent with IFF13[3] to convert the discount rate to nominal for the ratepayer revenues portion. The present value was brought forward three years to be representative of the 2014/15 year, when a decision on the plans is to be made (and to be consistent with the initial present value analysis).
- **Denominator**: The present value of the load forecast was taken using a 5.05% real rate. This provides a unit cost estimate that is in real cents/kWh (i.e. does not include inflation). The load forecast used for the original analysis was the 2012 Base Load Forecast[4] (provided in Appendix 4.2 of Hydro's initial NFAT filing) less the 2012 Base DSM Forecast for the Total Domestic Load. For the updated analysis the load was provided in MH-104-3 and the Base Load Forecast (again not including construction power) was used less the Base DSM, Level 1 DSM, Level 2 DSM and Level 3 DSM depending on the plan being calculated.
    - Since load information is only provided until 2047/48, the remaining years (to 2062) were set equal to the final year of data provided.
- The present value of revenues was divided by the present value of the corresponding load forecast (with DSM plan) to get the corresponding average unit cost (in cents/kWh). This was done for five year increments (from years 5 to 50).
- This was graphed for the 10th to 90th percentile distribution for the original filing and the ref-ref-ref scenario[5] (analysis same as above, just divided by PV of load forecast at the end) and was graphed against the original range and ref-ref-ref for all provided updated plans.

The Levelized cost is cumulative – so the Levelized cost for the entire period up to year 20 is shown at year 20 on the x axis of the graphs below. It doesn't show the cost in that year – it shows the PV of Levelized costs of all periods up to that year.

Note for Figures 4 through 6 below, the original analysis uses the expected value as originally filed in Exhibit MIPUG-9-2 while the update (Base DSM) uses the REF-REF-REF scenario.

[3] MH-97, page 3, Manitoba Consumer Price Index for year 2022/23
[4] Not including construction power
[5] REF-REF-REF used instead of expected value to be able to compare as expected value not possible to calculate with new information.

Figure 4: Plan 1 (All Gas) Unit Cost Comparison Original Filing (Range and Expected Value) vs. Update (Base DSM) (¢/kWh)

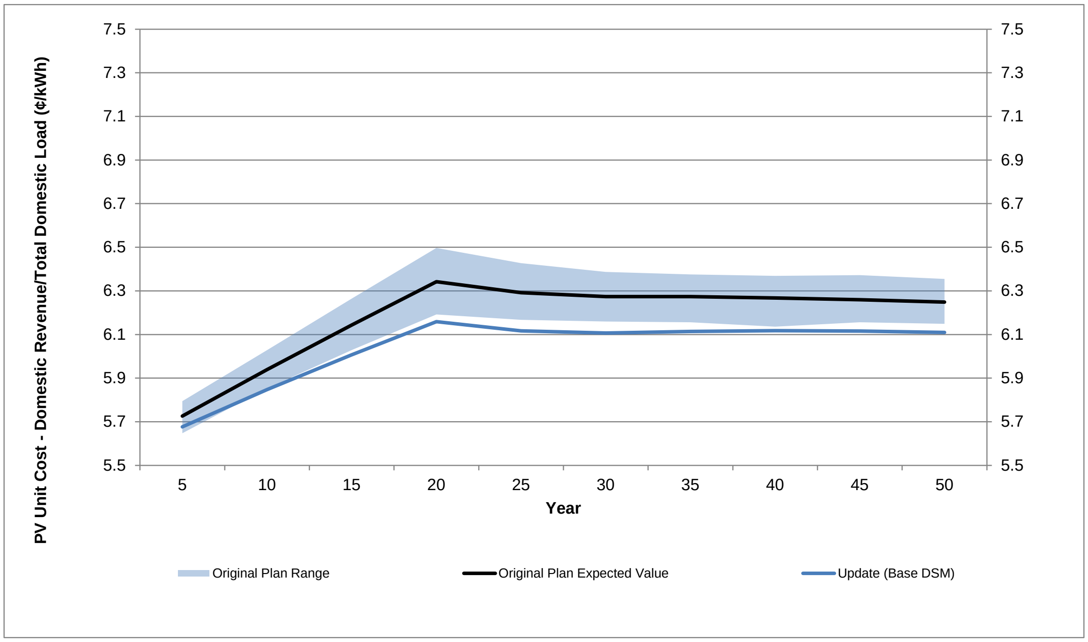


Figure 5: Plan 5/6 (K19/Gas/750MW) Unit Cost Comparison Original Filing (Range and Expected Value) vs. Update (Base DSM) (¢/kWh)

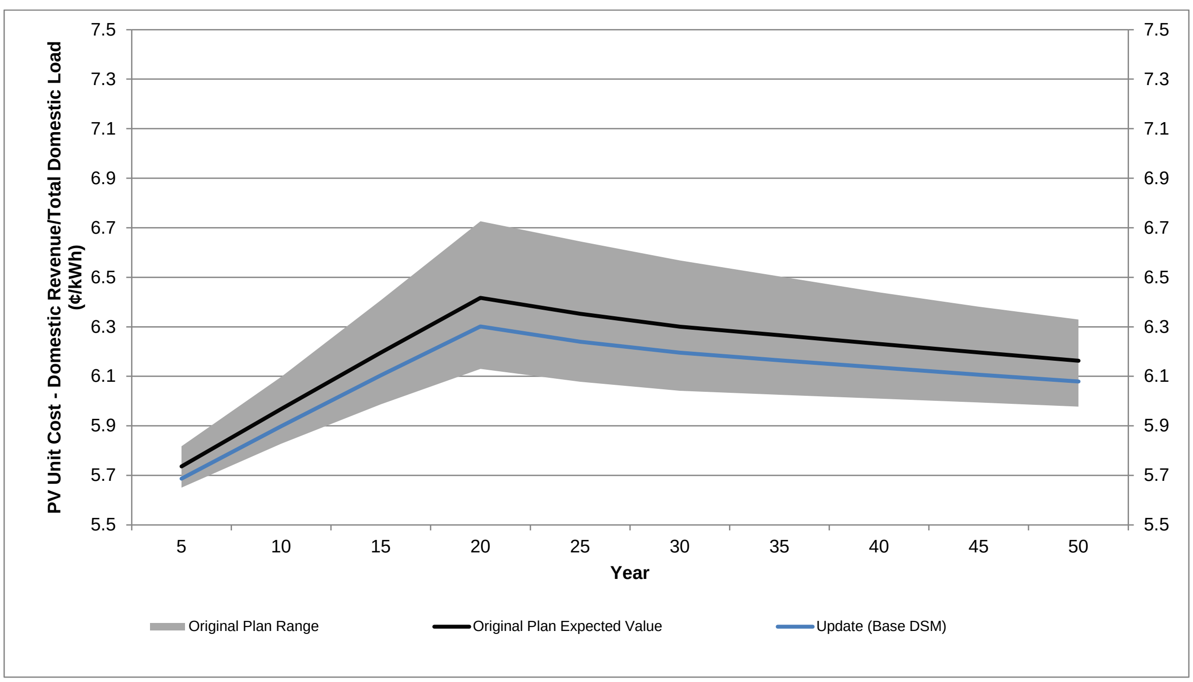
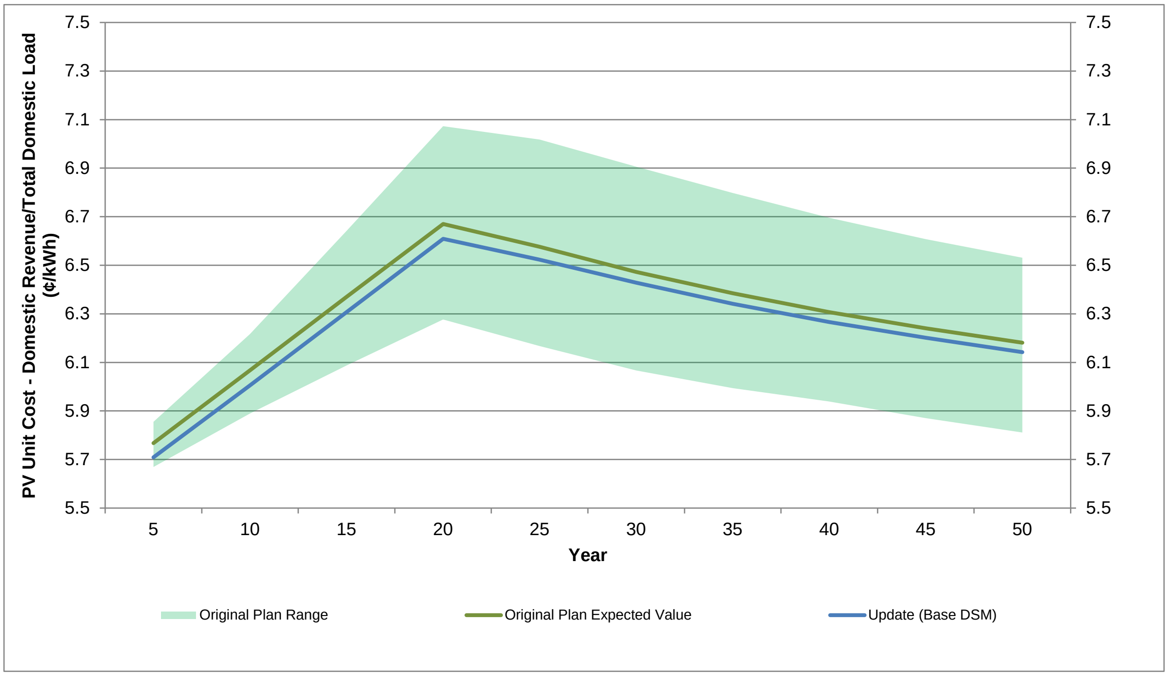


Figure 6: Plan 14 (PDP) Unit Cost Comparison Original Filing (Range and Expected Value) vs. Update (Base DSM) (¢/kWh)



Figures 4 through 6 above demonstrate the latest REF-REF-REF conditions which, in each case, are improvements to the average energy cost over the original filing Expected Value scenario. Only Plan 1 (All Gas), shown in Figure 4 above, has moved outside the original P90-P10 percentile range.

Does DSM make a difference to the Financial Outcomes for Ratepayers?

This Figures below shows that pursuing DSM is a consistent long-term upward driver of average rates. It's not the perfect information – because the DSM could be driving up average rates by saving significant of industrial load (which means less of low cost sales and relatively more higher cost GS Small and residential) but it's a useful measure nonetheless.

All DSM scenarios other than Plan 1 (All Gas) are also within the previous shaded horizon.

Figure 7: Plan 1 (All Gas) Unit Cost Comparison Original Filing (Range and REF-REF-REF) vs. Update (¢/kWh)

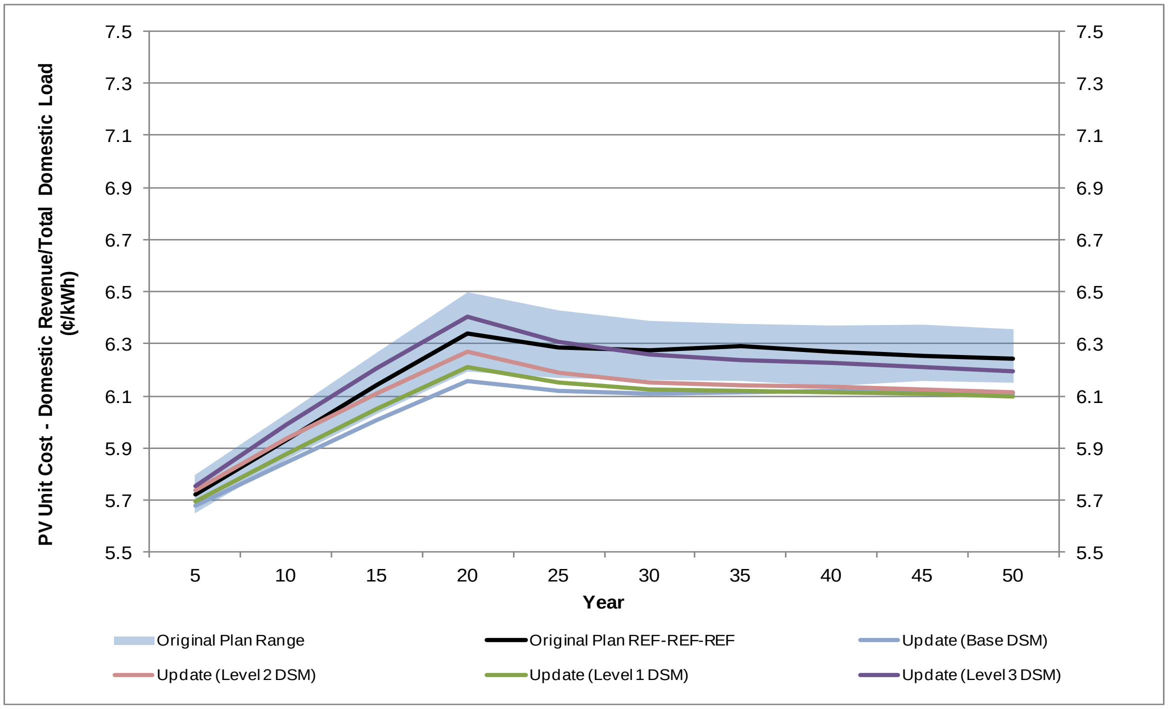


Figure 8: Plan 5/6 (K19/Gas/750MW) Unit Cost Comparison Original Filing (Range and REF-REF-REF) vs. Update (¢/kWh)

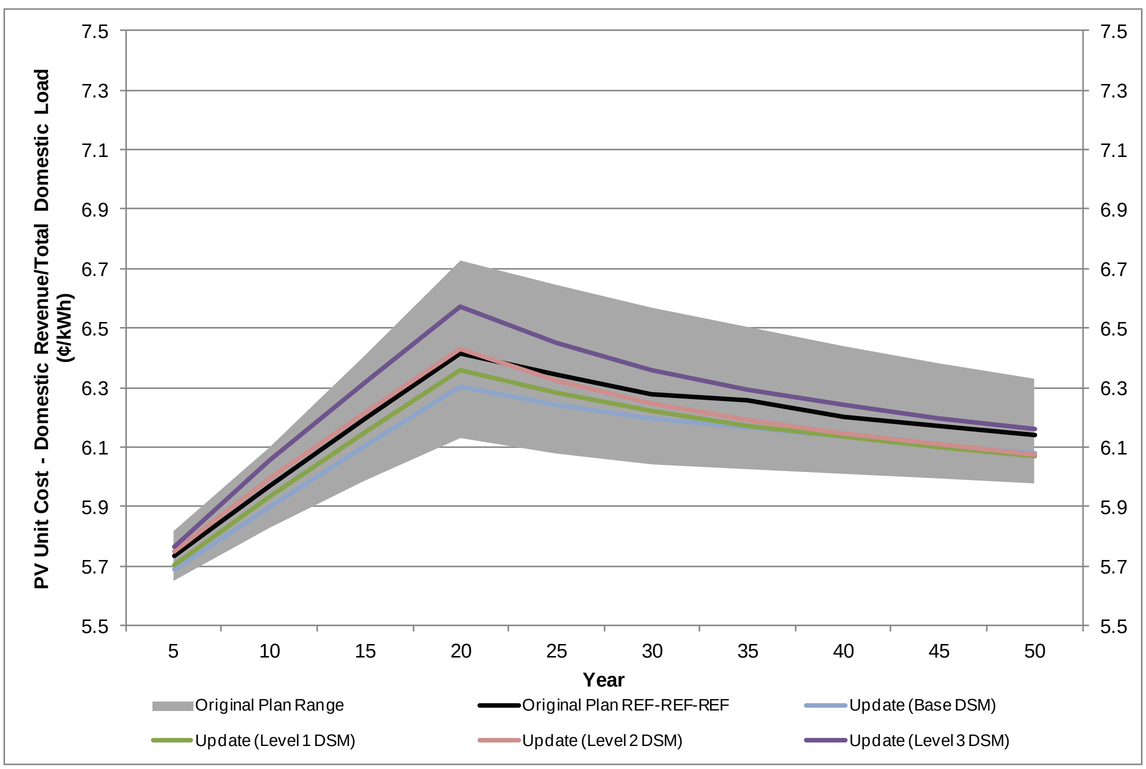
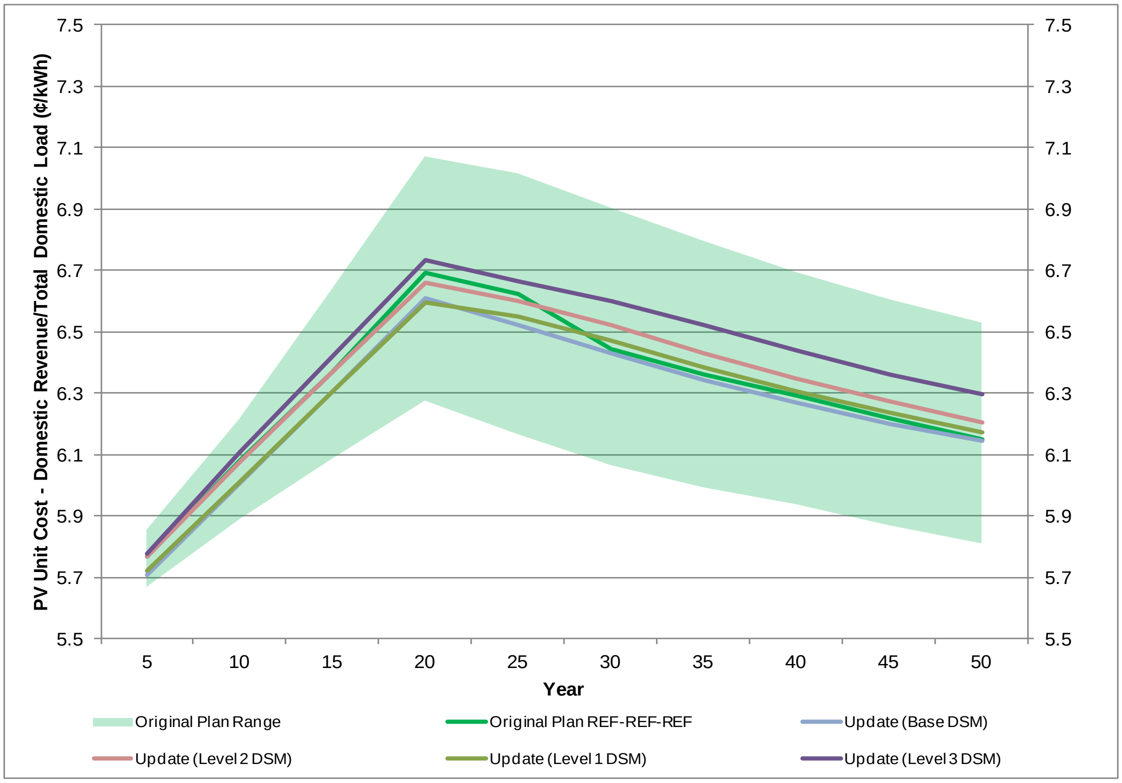


Figure 9: Plan 14 (PDP) Unit Cost Comparison Original Filing (Range and REF-REF-REF) vs. Update (¢/kWh)



Do the 2013 updates fundamentally change story or are they within the margin of uncertainty?

The above Figures show that for Plans 5 (K19/Gas/750MW) and 14 (PDP) the updated analysis for 2013, which changed a lot of factors including higher capital, higher inflation, lower forecast gas prices, higher forecast energy prices, no WPS investment, are still entirely within the original range of possibilities presented by Manitoba Hydro in the NFAT Business Case (the 90th and 10th percentiles risk horizons shown as the shading in the above graphs).

For Plan 1 (All Gas), the updates with DSM are a real improvement over the longer-term (see graphs above – new lines outside old shading). The decrease in impacts for gas outside of the original range of outcomes is likely due to the decrease in natural gas forecast prices in the updated filing.

What about the alternative rate strategies provided by Manitoba Hydro in MH-104-12?

Manitoba Hydro provided two alternative rate strategies in MH-104-12[6]:

- Alternative Rate Methodology #1 - applies 3.95% annual rate increases per year under each development plan until the Corporation's interest coverage ratio target of 1.20 is achieved. Once the target interest coverage is achieved, projected rates are adjusted annually to maintain the corporation's interest coverage ratio target of 1.20. This rate setting approach serves to minimize the erratic rate adjustments in the years immediately after 2031/32 and more closely aligns with how Manitoba Hydro may smooth these rate adjustments in practice.

[6] As per MH-104-12 Overview for April 11, 2014 Filing of the DSM Financial Evaluation, page 2

- Alternative Rate Methodology #2 - expands upon Alternative Rate Methodology #1 and minimizes the net losses projected during the first ten (10) years under Alternative #1. Even-annual rate increases above 3.95% were projected over the 2016 to 2022 timeframe to improve the projected net income/loss, the impact on retained earnings, the interest coverage ratios and the debt/equity ratios to an “acceptable level”. Beginning in 2023, if the target interest coverage ratio of 1.20 was not achieved, 3.95% annual rate increases were projected and if the target 1.20 was exceeded, 0.00% rate increases were projected until the interest coverage ratio returned to the 1.20 target. Once the target interest coverage is achieved, projected rates are adjusted annually to maintain the Corporation’s interest coverage ratio target of 1.20.

The two alternative rate strategies are adverse hits to Plan 1 (All Gas) in early years, and to some degree plan 5/6 (K19/Gas/750MW). The rates have a clear design strategy to be favourable for Plan 14 (PDP). The graphs below provide results comparing the alternative rate methods with the Main Submission Methodology and the original NFAT filing. Again graphs are provided in Levelized Cost of energy (cents/kW.h).

Figure 10: Plan 1 (All Gas) Unit Cost Comparison Original Filing (Range and REF-REF-REF) vs. Updated Methods with Level 2 DSM (¢/kWh)

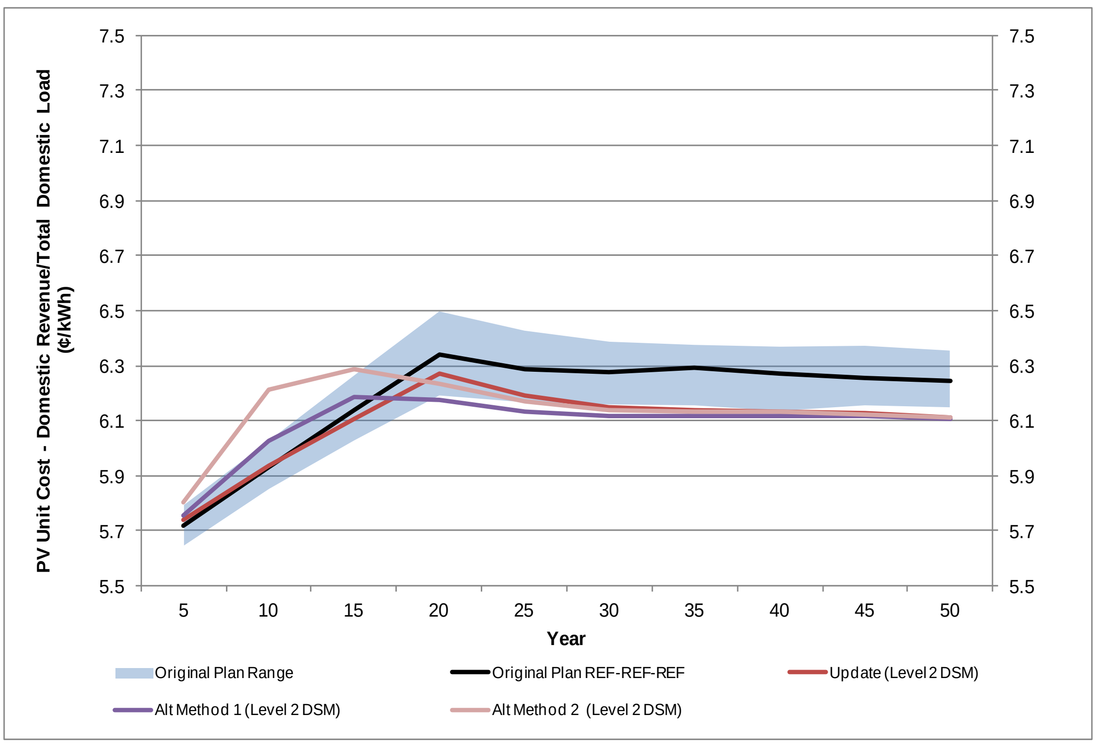


Figure 11: Plan 5/6 (K19/Gas/750MW) Unit Cost Comparison Original Filing (Range and REF-REF-REF) vs. Updated Methods with Level 2 DSM (¢/kWh)

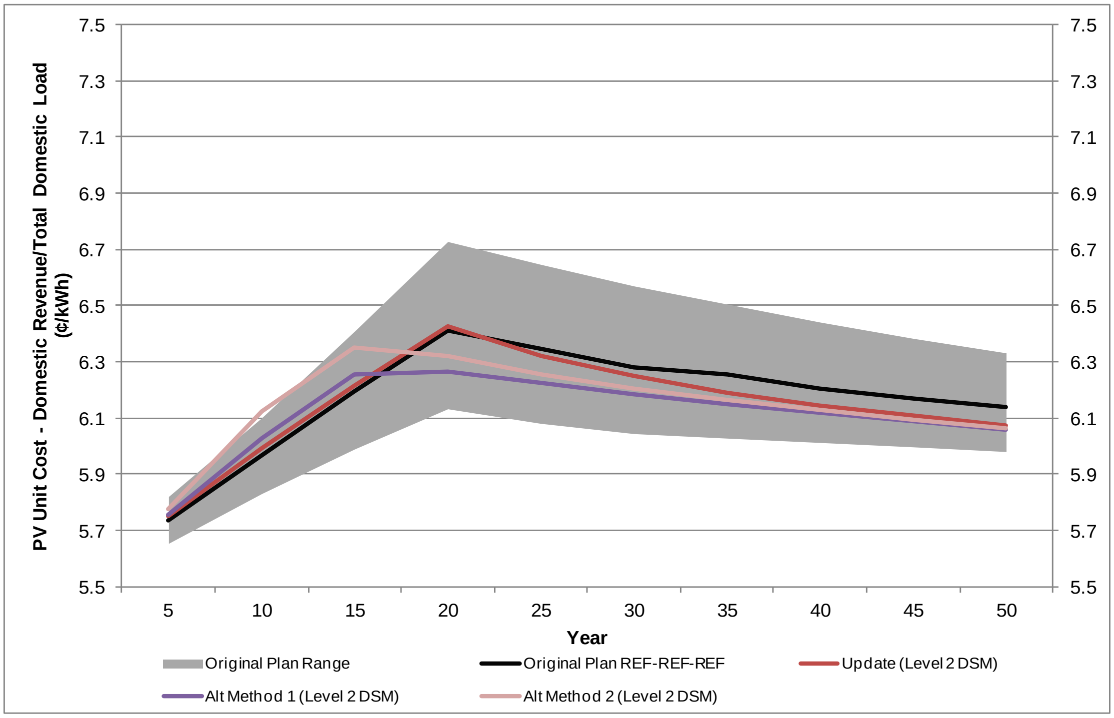
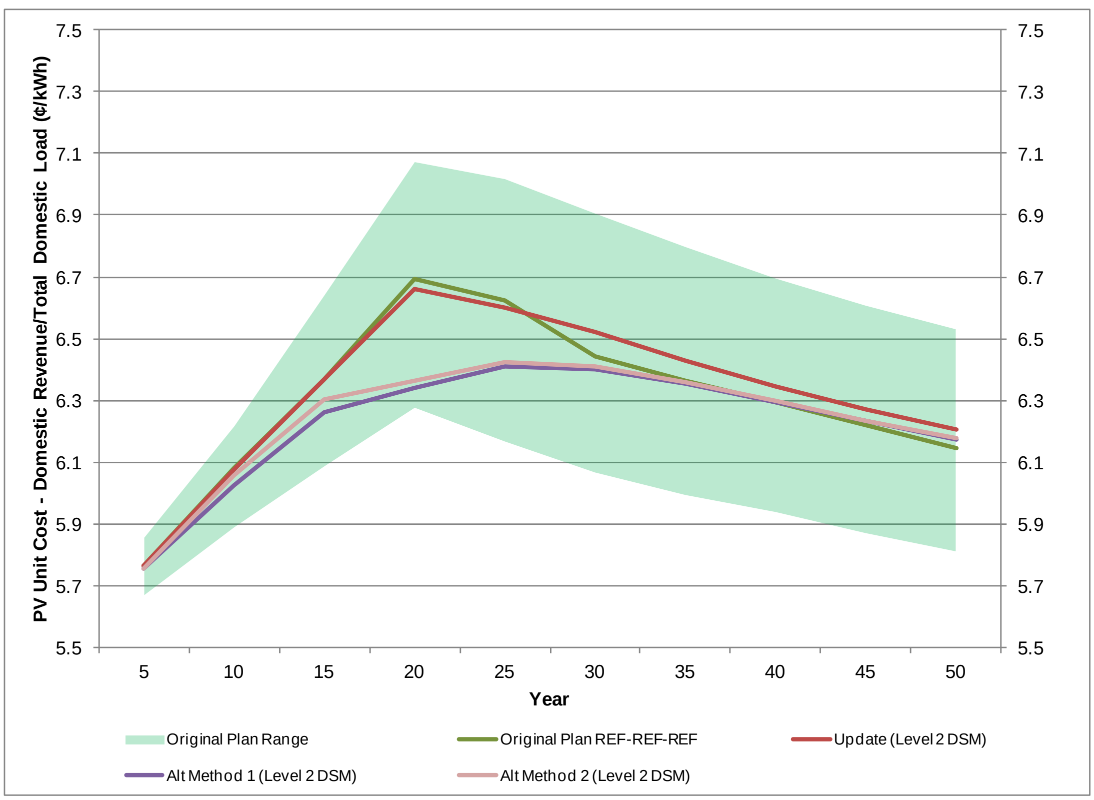


Figure 12: Plan 14 (PDP) Unit Cost Comparison Original Filing (Range and REF-REF-REF) vs. Updated Methods with Level 2 DSM (¢/kWh)



While the Alternative Rate Methodologies have some negative impacts on Plan 1 (All Gas) and Plan 5/6 (K19/Gas/750MW) the methodologies do limit the negative impact on ratepayers in the first 18 years for Plan 14 (PDP) by pushing some of the increases to later years.

At the same time, it is important to assess if these are realistic:

- These alternative rate plans yield heavily on the attainment of a 75:25 debt-equity ratio – mostly for Plan 14 (PDP).
    a. Under Alternative Rate Method #1 for Level 2 DSM the debt:equity ratio does not reach 75:25 until 2041/42. Comparing the Main Submission Methodology, which hits 75:25 in 2031/32, for Alt. Method #1 the ratio is only at 86:14 in this year. Additionally, the plan forecasts 5 years of net losses (2017/18 to 2021/22) before reaching this target. Manitoba Hydro has already stated that this degree of net losses may be unacceptable for other cases.

    b. Under Alternative Rate Method #2 for Level 2 DSM the debt:equity ratio also reaches 75:25 in 2041/42. In 2031/32 (the year the Main Submission Methodology hits the 75:25 target) Alt. Rate Method #2 has a forecast ratio of 85:15. This plan forecasts 3 - 4 years of net losses (2017/18 to 2020/21).

- On the other hand, under these alternative rate structures large retained earnings are still generated. For Plan 14 (PDP) reserves by 2031/32 reach $5.1 - $5.3 billion by 2031/32 by comparison (under Alt. Rate Method #1, the Plan 14 (PDP) reserves are $1.1 - $1.6 billion higher than Plan 5/6 (K19/Gas/750MW); under Alt. Rate Method #2 its $0.6 - $1.2 billion higher for Plan 14 over Plan 5/6. These far exceed the amount needed to pay for the extra drought risk under Plan 14 (PDP) as shown below:

Table 1: Fiscal Year 2034/35 Net Revenue (Millions of 2014 Dollars) – 5 Year Drought[7]

	Drought Risk ($ Millions)			Extra Drought Risk Comparing Plans ($ Millions)		
Energy Price	Plan 1	Plan 5 (6)	Plan 14 (PDP)	Plan 5 - Plan 1	Plan 14 - Plan 5	Plan 14 - Plan 1
Total Low	(1,220.2)	(1,289.7)	(1,414.3)	(69.5)	(124.5)	(194.1)
Total Ref	(2,014.6)	(2,195.7)	(2,437.6)	(181.1)	(241.9)	(423.0)
Total High	(2,909.0)	(3,217.3)	(3,567.8)	(308.3)	(350.5)	(658.8)

Therefore deciding on the credibility of the alternative rate methodologies comes down to which financial targets are imperative to Manitoba Hydro's financial strength.

Under Plan 14 (PDP) Alt. Rate Method #2, retained earnings reach $5.1 billion by 2031/32 with a five year drought of the worst years on record ending in 2034/35 costs $2.437 billion. If high energy price conditions arose ($3.567 billion drought) then presumably retained earnings would be higher to start with (as more revenues would be made in the export markets). So from the analysis it seems that reaching a 75:25 debt-equity target is not imperative, however from Manitoba Hydro's previous testimony indicates that it remains an important target to reach.

Note that these drought costs do not need to include compounding interest as by this time (2031/32 period) the forecast net income, under both Alternative Rate Methodologies for Plan 14 (PDP) is approximately $350 to $400M per year ($1.75 billion to $2.0 billion over 5 years). So even with a five year drought with the worst conditions on record, the $2.4 billion drought is not far off the forecast net income

[7] From MIPUG-20-4: MIPUG Book of Documents for the MH Economic Panel, March 12-13, 2014. Tab 9a, page 47. Calculated from MIPUG/MH I-007(a) from the NFAT Hearing.

without a drought ($2 billion) over the same time period. The total net losses by year 5 would be $400 million. Therefore compounding interest applied to these losses would be relatively small (e.g. $75 million).

Updated Load Forecast with DSM Levels Used in the Updated Financial Analysis

Figure 13 below shows the forecast domestic load for the 2013/14 Load Forecast with the four DSM scenarios used for the updated financial forecast.

Figure 13: Load Forecast Comparison for Domestic Need (GW.h)[8]

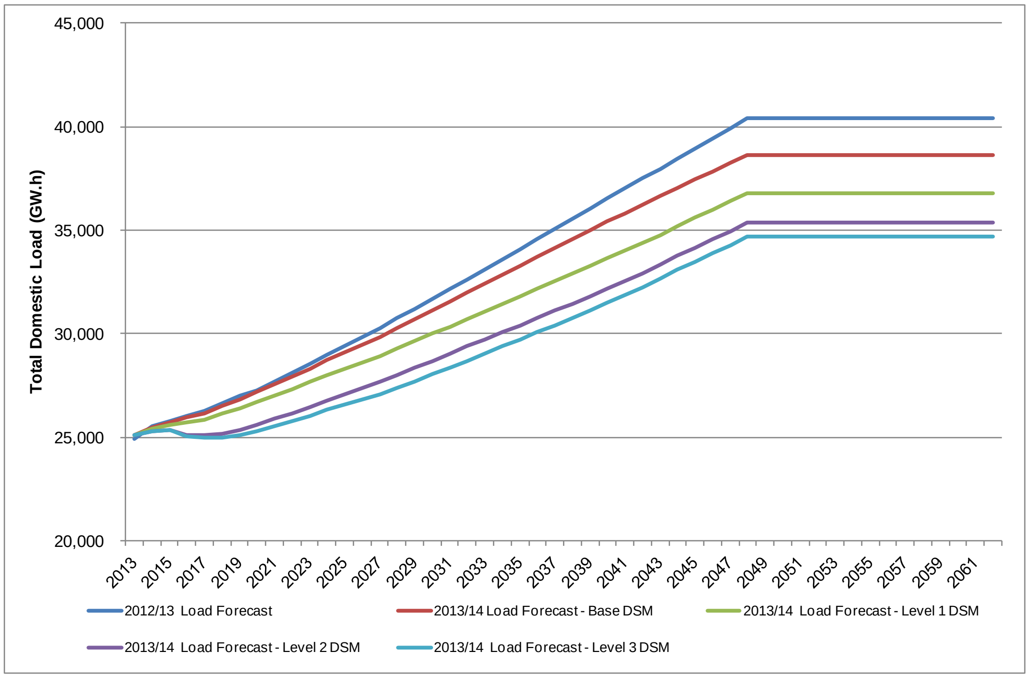
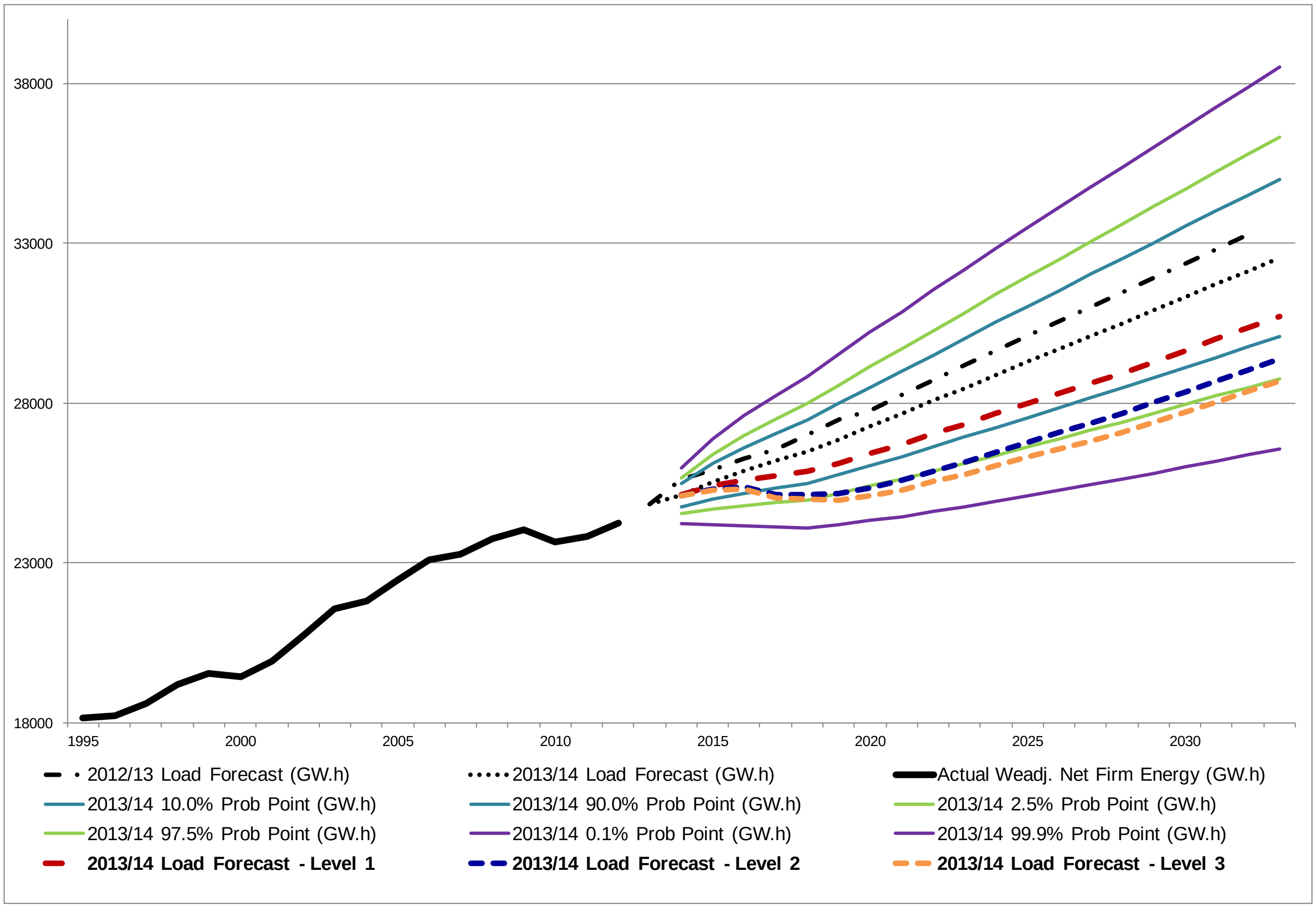


Figure 14 below compares the 2013/14 Domestic Load Forecast with various levels DSM with the original load forecast range (90th and 10th percentiles) set out in the NFAT Business Case filing and the increased percentile ranges provided in MH-103[9].

[8] Manitoba Domestic Load Forecast for 2012/13 from Appendix 4.2, page 18 and 19. Manitoba Domestic Load Forecast for 2013/14 with Base, Level 1, Level 2 and Level 3 DSM from MH-104-3. Load forecast amounts do not include construction power.

[9] Station service was deducted for consistency from Appendix D: 2013 Load Forecast, page 35

Figure 14: Manitoba Hydro Historical and Forecast Net Firm Energy (GW.h) 2012/13 and 2013/14 (with four DSM scenarios) Comparison to Percentile Ranges[10]



As can be seen from the above Figure, the 2013/14 forecast domestic load is outside of the 90/10 probability point range for DSM Levels 2 and 3, which are much close to the 97.5/2.5 probability point range.

[10] Actual Weather Adjusted Net Firm Energy from the following sources: 1993/94 - 2001/02 actual net firm load energy 2002/03 load forecast, 2010/12 GRA, Appendix 55, page 55. 2002/03 - 2011/12 actual net firm energy from 2012/13 load forecast from Appendix C of NFAT Business Case, page 38 (deducting station service on page 36). 2013/14 Load Forecast with various levels of DSM from MH-104-3. 2013/14 Probability Point ranges provided in MH-103. Load forecast amounts do not include construction power.