REFERENCE: Appendix E 2013- 2016 Power Smart Plan.

PREAMBLE: "The Board believes that it is fundamental that Manitoba Hydro enhances Demand-Side Management efforts from those reflected in the 2011 Power Smart Plan. (…) The Board does not agree with Manitoba Hydro’s decision to cut Demand-Side Management spending and targeted savings. (...) The Board urges Manitoba Hydro to incorporate Demand-Side Management programs into its plan that target higher levels of energy efficiency, as was recommended by Mr. Dunsky and endorsed by the Consumers’ Association of Canada (Manitoba) Inc. and the Green Action Centre." (Order 43-13, p. 42)

QUESTION:

Please specify all the changes made to the Power Smart Plan (for example: new budgets, new strategies, added programs and measures) to comply with order 43-13. Please also specify all changes that are contemplated by Manitoba Hydro but have not yet been implemented.

RESPONSE:

Please see Section 4.2.2 of Manitoba Hydro’s submission. Since releasing Manitoba Hydro’s 2013-2016 Power Smart Plan, a Community Geothermal program has been launched and staff are in the process of assessing strategies for all existing programs and some potential new opportunities. The details of these initiatives have not yet been finalized.

It is anticipated much of the information requested will be available with the next update to Manitoba Hydro’s Power Smart Plan. In accordance with The Energy Savings Act, the updated plan will be developed in consultation with the Minister responsible for Manitoba Hydro and will be prepared prior to March 31, 2014. Some information may be available on specific programs prior to this date and will be made available as the programs are approved and publically announced.

REFERENCE: Appendix E 2013- 2016 Power Smart Plan.

QUESTION:

Please quantify the forecasted impacts for each of these changes in terms of added budget, energy savings and peak savings, per year.

RESPONSE:

Please see Manitoba Hydro's response to CAC/GAC/MH I-001(a).

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 2; Page No.: 5

PREAMBLE: Market segmentation

QUESTION:

Please provide the reasons why the potential study uses a pre-2000/2000-present segmentation for the residential market.

RESPONSE:

The residential market was segmented at the year 2000 because the baseline energy performance of homes built after 2000 changed as a result of building code changes. In late 1999, a revised Manitoba Building Code took effect outlining requirements for insulation levels in southern Manitoba of R-40 in attics, R-20 in wall cavities, and R-20 in foundations. In the north, insulation level requirements were R-50 in attics, R-26 in walls cavities, and R-24 in foundations.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 2; Page No.: 5

QUESTION:

Please provide the number of buildings in Manitoba per market segment and year built (vintage).

RESPONSE:

Please see the chart below that outlines the number of accounts in Manitoba broken down by market segment and decade connected. Manitoba Hydro does not track data by building (e.g. a building may have more than one account such as strip mall).

	DECADE BUILT													
BFUNC$	1800s	1900s	1910s	1920s	1930s	1940s	1950s	1960s	1970s	1980s	1990s	2000s	2010s	TOTAL
BULK-METERED APARTMENT	5	25	18	10	12	7	21	198	586	159	130	131	20	1,322
CHURCH	30	83	97	100	328	93	215	245	196	211	119	109	16	1,842
COLLEGE	1	4	10	11	17	12	21	34	34	40	15	32	7	238
COMMON SERVICE	21	202	334	169	89	163	606	641	773	586	178	212	186	4,160
GROCERY STORE	9	46	47	58	82	56	109	115	257	319	167	157	19	1,441
HOSPITAL	25	4	12	14	9	2	24	28	49	32	28	33	5	265
HOTEL/MOTEL	5	39	26	21	57	30	102	127	115	139	71	109	14	855
MISCELLANEOUS COMMERCIAL	72	290	342	251	511	429	748	977	1,550	1,578	1,122	1,371	241	9,482
OFFICE	56	192	179	165	354	215	546	905	1,334	1,451	761	743	130	7,031
PERSONAL CARE HOMES	7	9	10	13	14	7	14	42	61	72	25	20	3	297
RECREATION FACILITY	18	61	60	56	318	127	197	288	375	358	235	163	34	2,290
RESTAURANT	7	51	64	74	82	112	186	226	333	498	267	257	49	2,206
RETAIL	41	189	173	160	254	287	524	678	1,150	1,084	606	816	86	6,048
SCHOOL	-	22	40	41	102	37	233	290	292	150	142	132	37	1,518
WAREHOUSE	8	26	23	39	94	75	142	283	474	438	315	249	41	2,207
TOTAL COMERCIAL	305	1,243	1,435	1,182	2,323	1,652	3,688	5,077	7,579	7,115	4,181	4,534	888	41,202
% OF TOTAL	0.7%	3.0%	3.5%	2.9%	5.6%	4.0%	9.0%	12.3%	18.4%	17.3%	10.1%	11.0%	2.2%	100.0%
AGRICULTURE/FOREST/FISH	16	70	85	77	365	160	199	260	550	560	592	548	23	3,505
CHEMICALS/TREATMENT	-	4	1	1	47	16	18	42	54	48	62	49	11	353
FOOD/BEVERAGE	-	5	12	7	15	22	19	40	76	64	28	26	4	318
MINING	-	-	-	-	2	2	1	1	10	10	6	18	1	51
MISCELLANEOUS INDUSTRIAL	7	67	64	29	76	61	133	241	345	209	163	161	17	1,573
PETROLEUM/OIL	-	-	1	3	4	-	8	14	3	1	5	9	2	50
PRIMARY METALS	1	-	5	-	2	1	4	8	14	7	2	4	-	48
PULP/PAPER	1	1	4	-	2	4	2	2	12	2	4	7	1	42
TOTAL INDUSTRIAL	25	147	172	117	513	266	384	608	1,064	901	862	822	59	5,940
% OF TOTAL	0.4%	2.5%	2.9%	2.0%	8.6%	4.5%	6.5%	10.2%	17.9%	15.2%	14.5%	13.8%	1.0%	100.0%
RES APARTMENT SUITE	136	1,519	4,043	2,455	887	1,189	7,307	10,321	8,935	10,757	1,623	4,222	4,147	57,541
RES COTTAGE	7	100	160	340	874	951	2,867	2,785	3,536	4,558	1,560	2,183	901	20,822
RES MOBILE HOME	8	39	30	37	135	99	152	354	2,072	2,593	1,992	1,455	140	9,106
RES MULTI INDIVIDUAL	199	938	1,167	569	331	572	1,617	2,971	7,517	1,230	701	980	587	19,379
RES MULTI SHARED	240	1,587	1,625	432	246	466	647	161	152	88	70	83	63	5,860
RES SINGLE DETACHED	1,645	10,891	19,626	15,587	13,210	26,366	41,586	39,905	52,896	50,105	31,195	36,238	15,966	355,216
RES TOWNHOUSE/ROWHOUSE	2	33	34	40	20	25	511	1,939	7,130	2,834	1,467	2,447	1,918	18,400
TOTAL RESIDENTIAL	2,237	15,107	26,685	19,460	15,703	29,668	54,687	58,436	82,238	72,165	38,608	47,608	23,722	486,324
% OF TOTAL	0.5%	3.1%	5.5%	4.0%	3.2%	6.1%	11.2%	12.0%	16.9%	14.8%	7.9%	9.8%	4.9%	100.0%
PROVINCIAL TOTAL	2,567	16,497	28,292	20,759	18,539	31,586	58,759	64,121	90,881	80,181	43,651	52,964	24,669	533,466
% OF TOTAL	0.5%	3.1%	5.3%	3.9%	3.5%	5.9%	11.0%	12.0%	17.0%	15.0%	8.2%	9.9%	4.6%	100.0%

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 5; Page No.: 2

PREAMBLE: Residential Heating

QUESTION:

Confirm that geothermal energy is the only higher-efficiency technology reviewed for heating in the residential market (ref.: 5-2).

RESPONSE:

In reference to Table 5-1 – Summary of Residential Equipment Measures, geothermal heat pumps were the only higher efficiency heating technology that was economic in the Manitoba market.

Air source heat pumps were initially screened, however as outlined in response to CAC/GAC/MH I-003(b), the opportunity was not economic in Manitoba. Manitoba Hydro will continue to monitor these alternative, higher efficiency heating options as the technologies progress and market prices adjust.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 5; Page No.: 2

QUESTION:

Confirm that air-source heat pumps are or can be available in Manitoba Hydro's service territory. Please explain why this technology was not retained for residential heating.

RESPONSE:

In warmer climates, air source heat pumps (ASHP) can be used for both heating and cooling of a residential home; and while they are available in Manitoba Hydro's service territory, they are typically used for cooling only or heating during the shoulder months because the coefficient of performance (COP) declines significantly as outside air temperatures drop. Due to the extreme outdoor temperatures reached and the duration of those temperatures in Manitoba during winter months, auxiliary heating is still required. ASHPs do not have sufficient capacity to heat a home at temperatures going below -30°C nor do they provide significant energy savings. Manitoba Hydro has monitored an air source heat pump system and the COP was 1.2. In addition to the low COP, the compressor ran for an additional 2000 hours, which significantly reduces the life of the compressor.

Air source heat pumps with variable speed compressors should provide increased efficiency in Manitoba's cold winter climate however they are relatively new to the Manitoba market and come at a higher capital cost than traditional heating systems.

As with all new emerging technologies, Manitoba Hydro will continue to monitor these systems to assess their performance.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 2; Page No.: 14

QUESTION:

Table 2-10 shows saturation levels of 36% for ceiling insulation and 50% for wall cavity insulation for existing single family homes. Please explain the exact meaning of these values. Does it mean that 64% of ceilings and 50% of wall cavities are uninsulated in that market?

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

These values identify the fraction of homes that already have the level of insulation equal to or better than the EE measure. The remaining market, 64% for ceiling insulation and 50% for wall insulation, may have some insulation however it is less than that of the EE insulation level. They represent the eligible market for the EE measure.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 6; Page No.: 9

PREAMBLE: Residential Lighting (LEDs)

QUESTION:

Confirm our understanding that until 2022/2023, the potential for adoption of LED lighting is set at zero.

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

At the time the analysis for this study was conducted, screw-in LED lamp technology in the residential sector was represented by two efficiency options within the LoadMap model. The first is the LED lamp that was already on the market but was very expensive relative to CFLs. The second is the LED 2020 lamp which was expected to be on the market in 2020 and would be more efficient and cost much less than the earlier-generation lamp. Please refer to the response to CAC-GAC/MH I-0023(f) for further detail. In the residential analysis, the LED lamp is not cost effective at any point in the study. Beginning in 2020, the LED 2020 lamp is cost effective.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 6; Page No.: 9

PREAMBLE: Residential Lighting (LEDs)

QUESTION:

Does Manitoba Hydro currently promote LED lighting? If so, then in which markets and for what specific uses (interior lighting, street lighting, parking lots, etc.)?

RESPONSE:

Through the Power Smart Commercial Lighting Program, Manitoba Hydro encourages commercial customers to upgrade to LED screw-in lamps for both indoor and outdoor use by offering financial incentives and disseminating information through its website and through commercial lighting retailers and contractors. Incentives also exist for purchasing LED hardwired fixtures to replace less efficient technologies both outdoors (wall-packs and parking lot standards) and indoors. An eligible product list is maintained and published to guide customers toward products that have been tested by Manitoba Hydro and which have sufficient warranties for commercial use.

Manitoba Hydro is in the final development stage of an LED Roadway Lighting conversion program. Seven test sites set up across the province are currently serving as pilot projects to test various fixtures to ensure LED meets performance requirements for illumination and durability. After the result of the pilots are reviewed, Manitoba Hydro will consult with municipal customers with the intent to bring forward a program design in Spring 2014 for a full scale phased program to convert roadway lighting to LED technology.

In addition to information and incentives, Manitoba Hydro also takes a very active technical role in the acceptance and adoption of LEDs specific to commercial end uses. Given the negative market experience with the earlier applications of the LED technology, specifically in holiday light strings, Manitoba Hydro recognizes that performance in commercial end-uses is critical to the overall adoption rate of LED technology. Testing support has been provided for applications such as street lighting, poultry barns, and general use bulbs.

In the residential market, Manitoba Hydro's current promotional efforts with respect to LED are part of an overall energy efficient lighting awareness strategy that includes compact fluorescent bulbs, timers and motion sensors. Manitoba Hydro has been monitoring the LED market and has recently seen an increase in the availability of this energy efficient lighting options for residential end-uses. The next Power Smart residential lighting campaign is currently being designed with a specific focus on promoting the LEDs for residential customers.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 6; Page No.: 9

QUESTION:

Does Manitoba Hydro anticipate adoption of LED lighting in whole or in part due to its current promotional efforts?

RESPONSE:

Manitoba Hydro's longstanding Power Smart support in the commercial lighting market has helped to put energy efficiency near the top of many customers' minds when shopping for lighting. Manitoba Hydro anticipates substantial growth in the adoption of LED lighting for both outdoor and indoor uses as a result of its ongoing promotional efforts. Financial incentives are offered for LED screw-in lamps, LED hard-wired fixtures, LED backlit signage and LED exit signs. Manitoba Hydro's Eligible Product List ensures that the products supported by the Commercial Lighting Program pass specific technical requirements. Sectors that are seeing the most uptake in LED lighting are agriculture facilities including poultry barns and nurseries; outdoor parking lot lighting; and screw-in lamp replacement in the retail and hospitality industry.

Manitoba Hydro's partners in the lighting industry are utilizing the Power Smart incentive program to promote the adoption of LED lighting. With continually lower product prices available to consumers, it is anticipated the adoption of LED lighting will increase at a rate much faster than previous technologies, as the energy savings, product warranty and long life along with the Commercial Lighting Program's technical support and incentives make it very appealing in the commercial sector.

In the residential market, Manitoba Hydro is currently developing its next Power Smart residential lighting campaign that would actively promote LEDs for residential applications and encourage customers to adopt the technology sooner than current market trends suggest they otherwise would. LED product availability is currently limited to lower wattage replacement and still carries a significant cost premium, therefore the campaign will work in partnership with retailers to maximize exposure to residential customers and also to ensure expanded product availability and selection. In the past, Power Smart programming has been shown to have a direct correlation to increased shelf space dedicated to energy efficient alternatives.

Due to the wide variation of general lighting applications in homes and the energy efficient products available, it is not anticipated that LED lighting will be adopted by all consumers for all lighting needs, although once the market matures the adoption rate is expected to be higher than was achieved for compact fluorescent bulbs due to the absence of issues related to mercury and delayed start-up.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 6; Page No.: 9

QUESTION:

How does the EnerNOC model compare options with very different useful lifes, for example incandescent versus CFLs versus LED lighting, especially regarding measure costs? Please provide a detailed example using actual inputs from the potential study.

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

As with most potential studies and assessments of energy efficiency, EnerNOC uses the total resource cost (TRC) to compute the benefit-cost ratio for each energy-efficiency measure. To account for varying lifetimes of measures, the costs and savings are divided by the measure life and compared to the annualized values in each year. An example is provided in the following table.

The gray shaded areas show inputs to the model.

Equipment Options includes the unit cost, lifetime, and energy use in the base year.

Avoided cost data includes the avoided energy cost, capacity cost and line losses in each year.

Utilization data are used to derive a multiplierthat is applied to energy use each year. For Manitoba, the only factor driving the change in the utilization index is the forecast of retail electricity prices and the price elasticities by end use.

Annual avoided costs are computed as the avoided energy cost times energy use (taking into account line losses) in each year. Costs are calculated separately for energy and demand.

Equipment cost includes material costs, labor costs, and any scaling factor that has been applied to raise or lower costs over the market life of the equipment.

Annualized total cost sums the Cost of Equipment plus the net present value of the Annual Operating Cost and Maintenance Cost across the life of the equipment. Then it applies an Annuity Payment formula to divide that sum across the lifetime. The 2010 value for Incandescent reflects the cost of equipment and two years of operating costs. The 2010 value for CFL reflects the 2010 cost of equipment and 9 years of operating costs.

Total Resource Cost test in this case is simply the ratio of the high-efficiency option (CFL) to the baseline (Incandescent), which is only calculated here through 2014 because incandescents go off market.

Economics	
Discount Rate	5.95%

LoadMAP Economic Decision Model (Excerpt)

Equipment Options and Data

Equipment	Label	Lifetime	Material Cost (per home)	Labor Cost	O&M Cost	On Market	Off Market	Cost Scalar	Base Year Usage (kWh)	Peak Factor (kW/kWh)	Peak use (kW)
1	Incandescent	2	$10.36	$0.00	$0.00	2010	2013	0.00%	1,408	0.00014	0.1969
4	CFL	9	$46.32	$0.00	$0.00	2010	2032	0.00%	314	0.00014	0.0440

Avoided cost data (using generic avoided cost forecast)

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Avoided Cost*	$ 4.62	$ 4.67	$ 4.71	$ 4.76	$ 4.81	$ 4.85	$ 4.90	$ 4.95	$ 5.00	$ 5.05	$ 5.10
Capacity Cost*	$ 13.12	$ 13.25	$ 13.39	$ 13.52	$ 13.66	$ 13.79	$ 13.93	$ 14.07	$ 14.21	$ 14.35	$ 14.50
Line Loss	14.00%	14.00%	14.00%	14.00%	14.00%	14.00%	14.00%	14.00%	14.00%	14.00%	14.00%

Utilization Data and Index (using a generic electricity price forecast)

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Electricity price	$ 63.49	$ 64.74	$ 67.19	$ 68.20	$ 69.22	$ 70.26	$ 71.32	$ 72.39	$ 73.47	$ 74.57	$ 75.69
Utilization index	1.0000	0.9971	0.9915	0.9893	0.9870	0.9848	0.9826	0.9804	0.9782	0.9760	0.9738

Annual cost of energy -- energy (avoided cost * annual kWh)[1]

Equipment	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Incandescent	$ 7.41	$ 7.47	$ 7.50	$ 7.56	$ 7.61	$ 7.67	$ 7.73	$ 7.79	$ 7.85	$ 7.91	$ 7.97
CFL	$ 1.65	$ 1.67	$ 1.67	$ 1.69	$ 1.70	$ 1.71	$ 1.73	$ 1.74	$ 1.75	$ 1.77	$ 1.78

Annual cost of demand (avoided capacity cost & peak kW)[1]

Equipment	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Incandescent	$ 2.95	$ 2.97	$ 2.98	$ 3.00	$ 3.03	$ 3.05	$ 3.07	$ 3.10	$ 3.12	$ 3.15	$ 3.17
CFL	$ 0.66	$ 0.66	$ 0.67	$ 0.67	$ 0.68	$ 0.68	$ 0.69	$ 0.69	$ 0.70	$ 0.70	$ 0.71

Cost of Equipment

Equipment	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Incandescent	$10.36	$ 10.36	$ 10.36	$ 10.36							
CFL	$46.32	$ 46.32	$ 46.32	$ 46.32	$ 46.32	$ 46.32	$ 46.32	$ 46.32	$ 46.32	$ 46.32	$ 46.32

Annualized Total Cost

Equipment	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Incandescent	$ 16.04	$ 16.10	$ 16.16	$ 16.34	$ -	$ -	$ -	$ -	$ -	$ -	$ -
CFL	$ 9.17	$ 9.18	$ 9.20	$ 9.25	$ 9.28	$ 9.30	$ 9.32	$ 9.35	$ 9.37	$ 9.39	$ 9.42

Total Resource Cost Test (Benefit/Cost)[2]

Equipment	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Incandescent	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
CFL	1.75	1.75	1.76	1.77	n/a	n/a	n/a	n/a	n/a	n/a	n/a

[1] The difference between the annual cost of energy + demand for the two equipment options equals the "benefit" of the higher-efficiency option (CFL)

[2] This is computed here simply as the ratio of the annualized cost. If you were to take the ratio of the two annualized cost formulas, it would look more consistent with the TRC formula.

*As Manitoba Hydro's avoided energy and capacity values are confidential, these values are included to demonstrate the calculation and are not Mantioba Hydro values

1

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 6; Page No.: 9

QUESTION:

In 2020/2021, when LED lighting does pass the economic screen, what will be the market share for LED and how is it attributed?

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

The Market Acceptance Rates and the Program Implementation Factors determine the market share for LED lamps for Market Potential and Achievable Potential, respectively. The following table shows the purchase-share logic for four cases for the LED lamps:

- The baseline projection shows what customers will do in absence of any programs:
  - 2% will purchase the LED lamps (even though they are not cost effective); and
  - 0% will purchase the LED 2020 lamps, even when they become cost effective in 2020.
- The Economic Potential shows that all customers will purchase the LED 2020 lamp starting in 2020.
- The Market Potential shares are developed by applying the Market Acceptance Rates to the purchase shares for Economic Potential.
- The Achievable Potential shares are developed by applying the Program Implementation Factors to the purchase shares for Market Potential.

Label	Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
LED	Baseline Forecast	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
LED (2020)	Baseline Forecast	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

For the Economic Potential forecast, all customers choose the most efficient, cost-effective option. In this analysis, this option is LED (2020), which is cost effective starting in 2020.

Label	Case	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
LED	Economic Potential	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LED (2020)	Economic Potential	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

For the Market Potential forecast, the purchase shares for Market Potential are computed as Economic Potential purchase shares multiplied by the Market Acceptance Rates in each year.

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Market Acceptance Rate (MAR) ==>		**0%**	**0%**	**0%**	**25%**	**25%**	**30%**	**45%**	**80%**	**80%**	**80%**	**80%**	**80%**	**95%**	**95%**	**95%**	**95%**	**95%**	**95%**	**95%**	**95%**	**95%**	**95%**	**95%**
LED	Market Potential	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
LED (2020)	Market Potential	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**80%**	**80%**	**95%**	**95%**	**95%**	**95%**	**95%**	**95%**	**95%**	**95%**	**95%**	**95%**	**95%**

For the Achievable Potential forecast, the purchase shares for Achievable Potential are computed as Market Potential purchase shares multiplied by the Program Implementation Factors in each year.

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Program Implementation Factor (PIF) ==>		**0%**	**0%**	**17%**	**26%**	**35%**	**32%**	**31%**	**30%**	**30%**	**29%**	**29%**	**29%**	**28%**	**31%**	**33%**	**35%**	**38%**	**40%**	**43%**	**45%**	**47%**	**47%**	**47%**
LED	Achievable Potential	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	1%	1%	1%	1%	1%
LED (2020)	Achievable Potential	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	**23%**	**23%**	**27%**	**29%**	**31%**	**34%**	**36%**	**38%**	**40%**	**43%**	**45%**	**45%**	**45%**

REFERENCE: Appendix 4.3 Demand Side Management Potential Study.

PREAMBLE: Measures

QUESTION:

Please provide a list of all measures that EnerNOC is aware of that were excluded from the initial (technical) level of analysis.

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

Sector	End-Use	Energy Efficiency Measure
Residential	Heating / Cooling	Heat Pump - Room, High Efficiency Air Source
Residential	HVAC (all)	Insulation, Ducting
Residential	HVAC (all)	Ducting, Repair and Sealing
Residential	Cooling	Windows, Install reflective film
Residential	Cooling	Roofs, High Reflectivity
Residential	HVAC (all)	Thermostat, Clock/Programmable
Residential	Water Heating	Water Heater, Heat Pump
Residential	Water Heating	Water Heater, Solar
Residential	Water Heating	Water Heater, Ground-Source Heat Pump
Residential	Water Heating	Hot Water System Pumps, High Efficiency
Residential	Water Heating	Water Heater, Thermostat Setback
Residential	Water Heating	Water Heating, Heat Trap

Residential	Interior Lighting	Fluorescent Torchieres
Residential	Exterior Lighting	Compact Fluorescent Lamps, Screw-In
Residential	Appliances	Clothes Dryer, Heat Pump
Residential	Appliances	Clothes Dryer, Microwave
Residential	Appliances	Clothes Dryer Duct Heat Recovery
Residential	Cooling	Evaporative Cooler
Residential	Water Heating	Water Heater - Electric, tankless
Commercial	Cooling	Chilled Water, Reset
Commercial	Cooling	Air Conditioner, Evaporative Cooler
Commercial	Cooling	Thermal Energy Storage - Cooling
Commercial	HVAC	Ducting, Insulation
Commercial	HVAC	Ducting, Repair and Sealing
Commercial	Water Heating	Water Heater - Electric, Tankless
Commercial	Water Heating	Water Heating, Heat Trap
Commercial	Water Heating	Water Heating, Tank Blanket
Commercial	Water Heating	Water Heater, Install Timer
Commercial	Water Heating	Water Heater, Thermostat Setback
Commercial	Water Heating	Water Heating, Solar Water Heating System
Commercial	Heating	Ducting, Insulation
Commercial	Heating	Ducting, Repair and Sealing
Commercial	Misc.	Commercial Washer
Commercial	Misc.	Commercial Dryer
Commercial	Interior Lighting	Fluorescent, Delamp and Install Reflectors

Industrial	Cooling	Thermal Energy Storage - Cooling
Industrial	Heating / Cooling	Heat Pump - Air-Source, High-Efficiency
Industrial	Heating / Cooling	Heat Pump - Air-Source, Maintenance
Industrial	Heating / Cooling	Heat Pump - Ductless & Variable Refrigerant Flow System
Industrial	Heating / Cooling	Heat Pump - Room, High Efficiency
Industrial	Heating / Cooling	Heat Pump, Geothermal or Water Source
Industrial	HVAC	Ducting, Repair and Sealing
Industrial	HVAC	HVAC Retrocommissioning

REFERENCE: Appendix 4.3 Demand Side Management Potential Study.

QUESTION:

Please provide a list of all measures for which the incremental cost used in the study is higher than that in EnerNOC's database.

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

EnerNOC maintains a database that includes measure data from variety of data sources. The sources include the Northwest Power and Conservation Council workbooks, various technical reference manuals from around the U.S., other secondary sources (including the Navigant study mentioned below), and measure data from other studies performed by EnerNOC that are in the public domain. As such, there is no single set of data in the "EnerNOC database" that were used to develop costs and savings for the Manitoba study (or for any of our studies). Instead, when the measure data was developed for Manitoba Hydro, information was requested from Manitoba Hydro and supplemented with information from EnerNOC's set of database values. These sources and the database are updated on an ongoing basis and previous versions are no longer available. The specific source for each cost, savings, lifetime or applicability assumption in the Manitoba study was not tracked. Therefore, respectfully EnerNOC is not able to respond to this question.

Please refer to Appendices B, C and D of the DSM Potential Study filed as Appendix 4.3 of this submission for incremental costs and savings used in the DSM Potential Study.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study.

QUESTION:

Please provide a list of all measures for which the incremental cost used in the study is lower than that in EnerNOC's database.

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

Please see the response to CAC_GAC/MH I-005(b).

REFERENCE: Appendix 4.3 Demand Side Management Potential Study

QUESTION:

Please provide a list of all measures for which the associated savings are lower than those in EnerNOC's database.

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

Please see the response to CAC_GAC/MH I-005(b).

REFERENCE: Appendix 4.3 Demand Side Management Potential Study.

QUESTION:

Please provide a list of all measures for which the associated savings are higher than those in EnerNOC's database.

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

Please see the response to CAC/GAC/MH I-0005(b).

REFERENCE: Appendix 4.3 Demand Side Management Potential Study.

PREAMBLE: Economic screen inputs

QUESTION:

Please provide all general inputs and assumptions used for economic screening, including discount rates, energy avoided costs, capacity avoided costs, delivery losses, etc. In each case where applicable, please specify if these are real or nominal values.

RESPONSE:

The following inputs and assumptions were used:

- Real discount rate – 5.95%
- All-in levelized marginal value – 7.74¢/kW.h (2012$)
- Delivery losses – 10% for transmission and 4% for distribution

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 1; Page No.: 1

PREAMBLE: Methodology/TRC

QUESTION:

Please confirm that Manitoba Hydro's TRC accounts for other benefits that accrue to participants and that therefore can influence their interest in opting for more efficient equipment.

RESPONSE:

In Order 119/13 the PUB determined that it did not require this Information Request to be answered.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 1; Page No.: 1

QUESTION:

Please confirm that EnerNOC's TRC ignores those same benefits

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

EnerNOC's analysis approach typically does not include the quantification of non energy benefits in the calculation of cost-effectiveness. Clients wanting to assess non energy benefits conduct an in-depth analysis of the measures outside of the potential study. However, acknowledging that Manitoba Hydro recognizes water savings benefits in its analysis, the cost-effectiveness of measures with water savings were reviewed. Most measures either pass or fail the cost-effectiveness screen by a substantial margin so the inclusion of non energy benefits would not affect whether they are included or excluded from the analysis.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 1; Page No.: 1

PREAMBLE: Methodology/TRC

QUESTION:

Specify by how much GWh the economic potential would have increased had the same level of non-energy benefits been included in EnerNOC's TRC calculations.

RESPONSE:

The requested information is not within the scope of the consultant's retainer.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study

PREAMBLE: Methodology/Early replacement

QUESTION:

Does EnerNOC's model include both Lost Opportunity (natural replacement, new construction) and Discretionary opportunities (early retirement, early replacement)?

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

The lost opportunity measures are covered in the "equipment" module and the discretionary opportunities are covered in the "non-equipment" measures module of EnerNOC's model.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study.

QUESTION:

In the past 10 years, have Manitoba Hydro's programs been limited to Lost Opportunity measures, or have they included early retirement and early replacement programs?

RESPONSE:

Manitoba Hydro has included early retirement/replacement programs in its portfolio. Examples of these programs include the Commercial Lighting Program, the Refrigerator Retirement Program and the Water and Energy Saver Program.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study.

PREAMBLE: Methodology/Technological progress

QUESTION:

To what extent does the model account for rates of technological improvements (improvements in efficiency and/or reductions in incremental cost) of measures over time? Is that limited only to LEDs?

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

Technological improvements are incorporated into the model through the specification of efficiency options. These options are outlined in the following tables.

Sector	End Use	Fuel	Technology	Equipment	Label	Energy use relative to E1	Example Cost per Home	On Market	Off Market
Residential	Cooling	Electric	Central AC	E2	SEER 14 (Energy Star)	91.7%	$ 2,173	2010	2032
Residential	Cooling	Electric	Central AC	E3	SEER 15 (CEE Tier 2)	89.3%	$ 2,607	2010	2032
Residential	Cooling	Electric	Central AC	E4	SEER 16 (CEE Tier 3)	87.2%	$ 2,643	2010	2032
Residential	Cooling	Electric	Central AC	E6	SEER 21	80.3%	$ 4,345	2010	2032
Residential	Cooling	Electric	Room AC	E2	EER 10.8 (Energy Star)	90.7%	$ 469	2010	2032
Residential	Cooling	Electric	Room AC	E3	EER 11.0	89.1%	$ 498	2010	2032
Residential	Cooling	Electric	Room AC	E4	EER 12.0	81.7%	$ 1,055	2010	2032
Residential	Cooling	Electric	Geothermal Heat Pump	E2	EER 14.1, COP 3.3	93.1%	$ 1,580	2010	2032
Residential	Cooling	Electric	Geothermal Heat Pump	E3	EER 16, COP 3.5	88.7%	$ 1,656	2010	2032
Residential	Cooling	Electric	Geothermal Heat Pump	E4	EER 18, COP 3.8	85.4%	$ 1,781	2010	2032
Residential	Cooling	Electric	Geothermal Heat Pump	E5	EER 30, COP 5.0	76.1%	$ 2,032	2010	2032
Residential	Heating	Electric	Geothermal Heat Pump	E2	EER 14.1, COP 3.3	95.3%	$ 4,051	2010	2032
Residential	Heating	Electric	Geothermal Heat Pump	E3	EER 16, COP 3.5	91.8%	$ 4,244	2010	2032
Residential	Heating	Electric	Geothermal Heat Pump	E4	EER 18, COP 3.8	88.4%	$ 4,566	2010	2032
Residential	Heating	Electric	Geothermal Heat Pump	E5	EER 30, COP 5.0	86.0%	$ 5,209	2010	2032
Residential	Interior Lighting	Electric	Screw-in	E2	Infrared Halogen	81.2%	$ 105	2014	2019
Residential	Interior Lighting	Electric	Screw-in	E3	Infrared Halogen (2020)	31.5%	$ 105	2020	2032
Residential	Interior Lighting	Electric	Screw-in	E5	LED	14.6%	$ 1,291	2010	2032
Residential	Interior Lighting	Electric	Screw-in	E6	LED (2020)	7.9%	$ 650	2020	2032
Residential	Appliances	Electric	Clothes Dryer	E2	High Efficiency	95.1%	$ 475	2010	2032
Residential	Appliances	Electric	Clothes Dryer	E3	Baseline (2015+)	94.9%	$ 450	2015	2032
Residential	Appliances	Electric	Clothes Dryer	E4	High Efficiency (2015+)	88.5%	$ 550	2015	2032
Residential	Appliances	Electric	Dishwasher	E2	Standard (EF 0.63)	75.9%	$ 645	2010	2032
Residential	Appliances	Electric	Dishwasher	E3	Energy Star (EF 0.69)	69.3%	$ 650	2010	2032
Residential	Appliances	Electric	Dishwasher	E4	Energy Star (EF 0.73)	65.5%	$ 725	2011	2032
Residential	Appliances	Electric	Dishwasher	E5	AHAM (EF 0.73)	65.5%	$ 725	2013	2032
Residential	Appliances	Electric	Dishwasher	E6	Ultra Efficient (EF 1.1)	40.9%	$ 900	2010	2032
Residential	Appliances	Electric	Refrigerator	E2	Energy Star	91.4%	$ 650	2010	2032
Residential	Appliances	Electric	Refrigerator	E3	High Efficiency	87.8%	$ 1,050	2010	2032
Residential	Appliances	Electric	Refrigerator	E4	AHAM (2014)	81.7%	$ 843	2014	2032
Residential	Appliances	Electric	Refrigerator	E5	High Efficiency (2014)	76.4%	$ 1,320	2014	2032
Residential	Appliances	Electric	Freezer	E2	Energy Star	88.8%	$ 450	2010	2032
Residential	Appliances	Electric	Freezer	E3	High Efficiency	76.6%	$ 598	2010	2032
Residential	Appliances	Electric	Freezer	E4	AHAM (2014)	76.4%	$ 598	2014	2032
Residential	Appliances	Electric	Freezer	E5	High Efficiency (2014)	70.6%	$ 752	2014	2032
Residential	Appliances	Electric	Second Refrigerator	E2	Energy Star	91.4%	$ 650	2010	2032
Residential	Appliances	Electric	Second Refrigerator	E3	High Efficiency	87.8%	$ 1,050	2010	2032
Residential	Appliances	Electric	Second Refrigerator	E4	AHAM (2014)	81.7%	$ 843	2014	2032
Residential	Appliances	Electric	Second Refrigerator	E5	High Efficiency (2014)	76.4%	$ 1,320	2014	2032
Residential	Appliances	Electric	Second Freezer	E2	Energy Star	88.8%	$ 450	2010	2032
Residential	Appliances	Electric	Second Freezer	E3	High Efficiency	76.6%	$ 598	2010	2032
Residential	Appliances	Electric	Second Freezer	E4	AHAM (2014)	76.4%	$ 598	2014	2032
Residential	Appliances	Electric	Second Freezer	E5	High Efficiency (2014)	70.6%	$ 752	2014	2032
Residential	Electronics	Electric	TVs	E2	Energy Star (3.1)	80.0%	$ 525	2010	2010
Residential	Electronics	Electric	TVs	E3	Energy Star (4.1)	57.2%	$ 525	2010	2011
Residential	Electronics	Electric	Set-top Boxes/DVR	E2	Energy Star (2009)	70.0%	$ 302	2010	2011
Residential	Electronics	Electric	Set-top Boxes/DVR	E3	Energy Star (2011)	60.0%	$ 302	2011	2032
Residential	Heating	Natural Gas	Furnace	E2	AFUE 96%	94.4%	$ 6,800	2010	2032
Residential	Heating	Natural Gas	Boiler	E2	EF 0.82	99.3%	$ 14,841	2010	2032
Residential	Heating	Natural Gas	Boiler	E3	EF 0.85	95.8%	$ 16,696	2010	2032
Residential	Heating	Natural Gas	Boiler	E4	EF 0.95	84.7%	$ 23,189	2010	2032
Residential	Water Heating	Natural Gas	Water Heater	E2	EF 0.62	92.0%	$ 878	2010	2032
Residential	Water Heating	Natural Gas	Water Heater	E3	EF 0.64	89.1%	$ 1,009	2010	2032
Residential	Water Heating	Natural Gas	Water Heater	E4	EF 0.7	81.6%	$ 1,104	2010	2032
Residential	Water Heating	Natural Gas	Water Heater	E5	EF 0.76	75.0%	$ 1,198	2010	2032
Residential	Water Heating	Natural Gas	Water Heater	E6	Tankless	69.5%	$ 1,475	2010	2032
Residential	Water Heating	Natural Gas	Water Heater	E7	EF 0.86	66.4%	$ 2,000	2010	2032
Residential	Appliances	Natural Gas	Clothes Dryer	E2	Standard (AHAM)	95.0%	$ 400	2015	2032
Residential	Appliances	Natural Gas	Clothes Dryer	E3	Efficient	81.5%	$ 530	2010	2032
Residential	Miscellaneous	Natural Gas	Pool Heater	E2	EF .82	95.2%	$ 3,344	2010	2032
Residential	Miscellaneous	Natural Gas	Pool Heater	E3	EF .90	85.7%	$ 5,032	2010	2032

Sector	End Use	Fuel	Technology	Equipment	Label	Energy use relative to E1	Example Cost per Sq. Ft.	On Market	Off Market
Commercial	Cooling	Electric	Air-Cooled Chiller	E2	1.3 kw/ton, COP 2.7	86.7%	$ 4.17	2009	2010
Commercial	Cooling	Electric	Air-Cooled Chiller	E3	1.26 kw/ton, COP 2.8	84.0%	$ 4.41	2010	2032
Commercial	Cooling	Electric	Air-Cooled Chiller	E4	1.0 kw/ton, COP 3.5	66.7%	$ 4.66	2010	2032
Commercial	Cooling	Electric	Air-Cooled Chiller	E5	0.97 kw/ton, COP 3.6	64.7%	$ 4.91	2010	2032
Commercial	Cooling	Electric	Water-Cooled Chiller	E2	0.60 kw/ton, COP 5.9	80.3%	$ 2.32	2009	2010
Commercial	Cooling	Electric	Water-Cooled Chiller	E3	0.58 kw/ton, COP 6.1	77.7%	$ 2.54	2010	2032
Commercial	Cooling	Electric	Water-Cooled Chiller	E4	0.55 kw/Ton, COP 6.4	73.7%	$ 2.63	2010	2032
Commercial	Cooling	Electric	Water-Cooled Chiller	E5	0.51 kw/ton, COP 6.9	68.5%	$ 2.93	2010	2032
Commercial	Cooling	Electric	Water-Cooled Chiller	E6	0.50 kw/Ton, COP 7.0	67.2%	$ 3.02	2010	2032
Commercial	Cooling	Electric	Water-Cooled Chiller	E7	0.48 kw/ton, COP 7.3	64.5%	$ 3.11	2010	2032
Commercial	Cooling	Electric	Roof top AC	E2	EER 10.1	90.0%	$ 2.88	2010	2032
Commercial	Cooling	Electric	Roof top AC	E3	EER 11.2	79.9%	$ 3.18	2010	2032
Commercial	Cooling	Electric	Roof top AC	E4	EER 12.0	73.7%	$ 3.74	2010	2032
Commercial	Cooling	Electric	Roof top Heat Pump	E2	EER 10.3	89.1%	$ 2.79	2010	2032
Commercial	Cooling	Electric	Roof top Heat Pump	E3	EER 11.0	82.6%	$ 2.94	2010	2032
Commercial	Cooling	Electric	Roof top Heat Pump	E4	EER 11.7	76.9%	$ 3.71	2010	2032
Commercial	Cooling	Electric	Roof top Heat Pump	E5	EER 12.0	74.6%	$ 4.09	2010	2032
Commercial	Cooling	Electric	Other Cooling	E2	EER 10.0	97.7%	$ 1.47	2010	2011
Commercial	Cooling	Electric	Other Cooling	E3	EER 10.2	95.5%	$ 1.53	2010	2011
Commercial	Cooling	Electric	Other Cooling	E4	EER 10.4	93.4%	$ 1.59	2010	2011
Commercial	Cooling	Electric	Other Cooling	E5	EER 10.6	91.4%	$ 1.64	2010	2032
Commercial	Cooling	Electric	Other Cooling	E6	EER 10.8	89.5%	$ 1.70	2010	2032
Commercial	Cooling	Electric	Other Cooling	E7	EER 12.0	79.2%	$ 3.94	2010	2032
Commercial	Space Heating	Electric	Roof top Heat Pump	E2	EER 10.3	99.8%	$ 1.28	2010	2032
Commercial	Space Heating	Electric	Roof top Heat Pump	E3	EER 11.0	99.6%	$ 1.35	2010	2032
Commercial	Space Heating	Electric	Roof top Heat Pump	E4	EER 11.7	99.5%	$ 1.70	2010	2032
Commercial	Space Heating	Electric	Roof top Heat Pump	E5	EER 12.0	99.4%	$ 1.87	2010	2032
Commercial	Interior Lighting	Electric	Screw-in	E4	LED (2010)	18.0%	$ 0.84	2010	2019
Commercial	Interior Lighting	Electric	Screw-in	E6	LED (2020)	5.8%	$ 0.24	2020	2032
Commercial	Interior Lighting	Electric	High-Bay Fixtures	E2	LED (2010)	54.8%	$ 0.10	2010	2019
Commercial	Interior Lighting	Electric	High-Bay Fixtures	E6	LED (2020)	17.7%	$ 0.03	2020	2032
Commercial	Interior Lighting	Electric	Linear Fluorescent	E2	LED (2010)	75.2%	$ 7.95	2010	2019
Commercial	Interior Lighting	Electric	Linear Fluorescent	E6	LED (2020)	24.3%	$ 2.26	2020	2032
Commercial	Exterior Lighting	Electric	Screw-in	E4	LED (2010)	18.0%	$ 0.05	2010	2019
Commercial	Exterior Lighting	Electric	Screw-in	E5	LED (2020)	5.8%	$ 0.01	2020	2032
Commercial	Exterior Lighting	Electric	HID	E2	LED (2010)	86.6%	$ 0.69	2010	2019
Commercial	Exterior Lighting	Electric	HID	E4	LED (2020)	28.0%	$ 0.20	2019	2032
Commercial	Refrigeration	Electric	Walk-in Refrigerator	E2	10800 kWh/yr	74.0%	$ 0.36	2010	2032
Commercial	Refrigeration	Electric	Walk-in Refrigerator	E3	10000 kWh/yr	68.5%	$ 0.37	2010	2032
Commercial	Refrigeration	Electric	Walk-in Refrigerator	E4	9000 kWh/yr	61.6%	$ 0.40	2010	2032
Commercial	Refrigeration	Electric	Reach-in Refrigerator	E2	2500 kWh/yr	80.6%	$ 0.05	2010	2032
Commercial	Refrigeration	Electric	Reach-in Refrigerator	E3	2400 kWh/yr	77.4%	$ 0.05	2010	2032
Commercial	Refrigeration	Electric	Reach-in Refrigerator	E4	1500 kWh/yr	48.4%	$ 0.05	2010	2032
Commercial	Refrigeration	Electric	Glass Door Display	E2	14480 kWh/yr	93.4%	$ 0.08	2010	2032
Commercial	Refrigeration	Electric	Glass Door Display	E3	11700 kWh/yr	75.5%	$ 0.12	2010	2032
Commercial	Refrigeration	Electric	Glass Door Display	E4	8400 kWh/yr	54.2%	$ 0.08	2012	2032
Commercial	Refrigeration	Electric	Glass Door Display	E5	6800 kWh/yr	43.9%	$ 0.12	2012	2032
Commercial	Refrigeration	Electric	Open Display Case	E2	6535 kWh/yr	93.4%	$ 0.04	2010	2032
Commercial	Refrigeration	Electric	Open Display Case	E3	5350 kWh/yr	76.4%	$ 0.04	2012	2032
Commercial	Refrigeration	Electric	Open Display Case	E4	5300 kWh/yr	75.7%	$ 0.05	2010	2032
Commercial	Refrigeration	Electric	Open Display Case	E5	4350 kWh/yr	62.1%	$ 0.05	2012	2032
Commercial	Refrigeration	Electric	Icemaker	E2	6.3 kWh/100 lbs	89.5%	$ 0.05	2010	2032
Commercial	Refrigeration	Electric	Icemaker	E3	6.0 kWh/100 lbs	85.2%	$ 0.05	2010	2032
Commercial	Refrigeration	Electric	Icemaker	E4	5.5 kWh/100 lbs	78.2%	$ 0.07	2010	2032
Commercial	Refrigeration	Electric	Vending Machine	E2	2400 kWh/year	70.6%	$ 0.06	2010	2032
Commercial	Refrigeration	Electric	Vending Machine	E3	1700 kWh/year	50.0%	$ 0.07	2010	2032
Commercial	Miscellaneous	Electric	Non-HVAC Motors	E2	Standard (EPAct 2015)	99.4%	$ 0.03	2015	2032
Commercial	Miscellaneous	Electric	Non-HVAC Motors	E3	High Efficiency	98.7%	$ 0.03	2010	2014
Commercial	Miscellaneous	Electric	Non-HVAC Motors	E4	High Efficiency (2015)	98.1%	$ 0.03	2015	2032
Commercial	Miscellaneous	Electric	Non-HVAC Motors	E5	Premium (NEMA)	97.5%	$ 0.03	2010	2014
Commercial	Miscellaneous	Electric	Non-HVAC Motors	E6	Premium (NEMA 2015)	96.8%	$ 0.03	2015	2032

Sector	End Use	Fuel	Technology	Equipment	Label	Energy use relative to E1	Example Cost per Sq. Ft.	On Market	Off Market
Commercial	Space Heating	Natural Gas	Furnace	E2	EF .91	98.9%	$ 1.44	2010	2032
Commercial	Space Heating	Natural Gas	Boiler	E2	EF .80	95.0%	$ 3.34	2010	2014
Commercial	Space Heating	Natural Gas	Boiler	E3	EF .82	92.7%	$ 3.70	2010	2014
Commercial	Space Heating	Natural Gas	Boiler	E4	EF .85	89.4%	$ 4.23	2010	2032
Commercial	Space Heating	Natural Gas	Boiler	E5	EF .96	79.2%	$ 7.35	2010	2032
Commercial	Space Heating	Natural Gas	Other Heating	E2	AFUE .75	94.3%	$ 2.24	2010	2032
Commercial	Space Heating	Natural Gas	Other Heating	E3	AFUE .76	93.0%	$ 2.30	2010	2032
Commercial	Space Heating	Natural Gas	Other Heating	E4	AFUE .77	91.6%	$ 2.42	2010	2032
Commercial	Space Heating	Natural Gas	Other Heating	E5	AFUE .80	88.0%	$ 2.77	2010	2032
Commercial	Water Heating	Natural Gas	Water Heating	E2	EF .80	96.3%	$ 0.29	2010	2017
Commercial	Water Heating	Natural Gas	Water Heating	E3	EF .94	81.9%	$ 0.44	2010	2032
Commercial	Miscellaneous	Natural Gas	Pool Heater	E2	EF .82	95.1%	$ -	2010	2032
Commercial	Miscellaneous	Natural Gas	Pool Heater	E3	EF .90	86.7%	$ -	2010	2032
Commercial	Miscellaneous	Natural Gas	Pool Heater	E4	EF .95	82.1%	$ -	2010	2032

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Sector	End Use	Fuel	Technology	Equipment	Label	Energy use relative to E1	Example Cost	On Market	Off Market
Industrial	Cooling	Electric	Air-Cooled Chiller	E1	1.5 kw/ton, COP 2.3	100.0%	$ 18,258	2010	2010
Industrial	Cooling	Electric	Air-Cooled Chiller	E2	1.3 kw/ton, COP 2.7	86.7%	$ 22,766	2010	2010
Industrial	Cooling	Electric	Air-Cooled Chiller	E3	1.26 kw/ton, COP 2.8	84.0%	$ 24,119	2010	2032
Industrial	Cooling	Electric	Air-Cooled Chiller	E4	1.0 kw/ton, COP 3.5	66.7%	$ 25,471	2010	2032
Industrial	Cooling	Electric	Air-Cooled Chiller	E5	0.97 kw/ton, COP 3.6	64.7%	$ 26,824	2010	2032
Industrial	Cooling	Electric	Water-Cooled Chiller	E1	0.75 kw/ton, COP 4.7	100.0%	$ 8,475	2010	2010
Industrial	Cooling	Electric	Water-Cooled Chiller	E2	0.60 kw/ton, COP 5.9	80.3%	$ 9,383	2010	2010
Industrial	Cooling	Electric	Water-Cooled Chiller	E3	0.58 kw/ton, COP 6.1	77.6%	$ 10,291	2010	2032
Industrial	Cooling	Electric	Water-Cooled Chiller	E4	0.55 kw/Ton, COP 6.4	73.7%	$ 10,655	2010	2032
Industrial	Cooling	Electric	Water-Cooled Chiller	E5	0.51 kw/ton, COP 6.9	68.5%	$ 11,865	2010	2032
Industrial	Cooling	Electric	Water-Cooled Chiller	E6	0.50 kw/Ton, COP 7.0	67.2%	$ 12,229	2010	2032
Industrial	Cooling	Electric	Water-Cooled Chiller	E7	0.48 kw/ton, COP 7.3	64.5%	$ 12,592	2010	2032
Industrial	Cooling	Electric	Roof top AC	E1	EER 9.2	100.0%	$ 13,862	2010	2032
Industrial	Cooling	Electric	Roof top AC	E2	EER 10.1	90.0%	$ 15,579	2010	2032
Industrial	Cooling	Electric	Roof top AC	E3	EER 11.2	79.9%	$ 17,163	2010	2032
Industrial	Cooling	Electric	Roof top AC	E4	EER 12.0	73.7%	$ 20,199	2010	2032
Industrial	Cooling	Electric	Other Cooling	E1	EER 9.8	100.0%	$ 15,665	2010	2011
Industrial	Cooling	Electric	Other Cooling	E2	EER 10.0	97.7%	$ 19,861	2010	2011
Industrial	Cooling	Electric	Other Cooling	E3	EER 10.2	95.5%	$ 20,630	2010	2011
Industrial	Cooling	Electric	Other Cooling	E4	EER 10.4	93.4%	$ 21,399	2010	2011
Industrial	Cooling	Electric	Other Cooling	E5	EER 10.6	91.4%	$ 22,168	2010	2032
Industrial	Cooling	Electric	Other Cooling	E6	EER 10.8	89.5%	$ 22,938	2010	2032
Industrial	Cooling	Electric	Other Cooling	E7	EER 12.0	79.2%	$ 53,148	2010	2032
Industrial	Interior Lighting	Electric	Screw-in	E4	LED (2010)	18.0%	$ 757	2010	2019
Industrial	Interior Lighting	Electric	Screw-in	E6	LED (2020)	5.8%	$ 215	2020	2032
Industrial	Interior Lighting	Electric	High-Bay Fixtures	E2	LED (2010)	54.8%	$ 657	2010	2019
Industrial	Interior Lighting	Electric	High-Bay Fixtures	E6	LED (2020)	17.7%	$ 186	2020	2032
Industrial	Interior Lighting	Electric	Linear Fluorescent	E2	LED (2010)	75.2%	$ 28,210	2010	2019
Industrial	Interior Lighting	Electric	Linear Fluorescent	E6	LED (2020)	24.3%	$ 8,006	2020	2032
Industrial	Exterior Lighting	Electric	Screw-in	E4	LED (2010)	18.0%	$ -	2010	2019
Industrial	Exterior Lighting	Electric	Screw-in	E5	LED (2020)	5.8%	$ -	2020	2032
Industrial	Exterior Lighting	Electric	HID	E2	LED (2010)	86.6%	$ 3,608	2010	2019
Industrial	Exterior Lighting	Electric	HID	E4	LED (2020)	28.0%	$ 1,024	2019	2032
Industrial	Heating	Natural Gas	Furnace	E2	EF .80	0.0%	$ -	2010	2032
Industrial	Heating	Natural Gas	Furnace	E3	EF .81	0.0%	$ -	2010	2032
Industrial	Heating	Natural Gas	Furnace	E4	EF .82	0.0%	$ -	2010	2032
Industrial	Heating	Natural Gas	Furnace	E5	EF .90	0.0%	$ -	2010	2032
Industrial	Heating	Natural Gas	Furnace	E6	EF .91	0.0%	$ -	2010	2032
Industrial	Heating	Natural Gas	Boiler	E2	EF .80	0.0%	$ -	2010	2014
Industrial	Heating	Natural Gas	Boiler	E3	EF .82	0.0%	$ -	2010	2014
Industrial	Heating	Natural Gas	Boiler	E4	EF .85	0.0%	$ -	2010	2032
Industrial	Heating	Natural Gas	Boiler	E5	EF .96	0.0%	$ -	2010	2032
Industrial	Heating	Natural Gas	Other Heating	E2	AFUE .75	94.3%	$ -	2010	2032
Industrial	Heating	Natural Gas	Other Heating	E3	AFUE .76	93.0%	$ -	2010	2032
Industrial	Heating	Natural Gas	Other Heating	E4	AFUE .77	91.6%	$ -	2010	2032
Industrial	Heating	Natural Gas	Other Heating	E5	AFUE .80	88.0%	$ -	2010	2032

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REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 1; Page No.: 1

PREAMBLE: Screening level

QUESTION:

Please confirm that the benefit/cost ratio threshold used to screen every measure individually is 1, i.e. that any measure individually below 1 is excluded. If the answer cannot be confirmed, please identify any measure included where the individual measure was below 1.

RESPONSE:

Confirmed.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 1; Page No.: 1

PREAMBLE: B/C Scenarios

QUESTION:

What is the average benefit/cost ratio attained as a whole, and per sector?

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

The following table outlines the benefit/cost ratios by potential type, measure type and sector. It should be noted that the benefit/cost ratios are calculated annually, thus the table shows the values for each year of the study.

Benefit/Cost Ratios by Potential Type, Measure Type and Sector

											Achievable Potential											
Measure Type	**Sector**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Equipment	Residential	1.07	1.55	1.95	1.68	1.40	1.95	1.71	1.40	1.24	1.21	1.25	1.29	1.29	1.26	1.30	1.30	1.26	1.28	1.26	1.25	1.26
Equipment	Commercial	2.09	1.90	2.06	1.79	1.89	1.98	2.01	1.91	2.93	2.79	2.57	2.28	1.68	1.60	1.53	1.45	1.44	1.47	1.63	1.80	1.76
Equipment	Industrial	1.08	1.85	1.82	1.31	1.45	1.58	1.48	1.79	2.34	1.89	2.02	2.28	2.12	3.47	3.19	2.95	2.74	2.59	2.40	1.87	1.97
Measures	Residential	1.50	2.24	2.29	2.33	2.37	2.32	2.29	2.27	2.21	2.21	2.19	2.20	2.21	2.21	2.22	2.23	2.24	2.24	2.26	2.30	2.31
Measures	Commercial	2.23	2.23	2.24	2.25	2.19	2.19	2.15	2.13	2.05	1.99	2.33	2.16	2.16	2.15	2.14	2.10	2.00	1.76	1.25	0.69	0.39
Measures	Industrial	1.12	2.45	2.45	2.48	2.48	2.47	2.46	2.45	2.45	2.45	2.43	2.41	2.40	2.36	2.36	2.33	2.30	2.27	2.23	2.13	2.08
Equipment	All	1.06	1.85	2.05	1.77	1.84	1.97	1.97	1.86	2.80	2.66	2.45	2.18	1.64	1.59	1.53	1.45	1.43	1.46	1.57	1.68	1.64
Measures	All	1.60	2.25	2.30	2.34	2.38	2.34	2.31	2.29	2.25	2.24	2.24	2.23	2.24	2.23	2.24	2.24	2.24	2.23	2.22	2.23	2.22
All	All	1.56	2.09	2.19	2.10	2.15	2.17	2.15	2.07	2.56	2.47	2.35	2.21	1.92	1.89	1.86	1.82	1.81	1.82	1.87	1.93	1.91
											Market Potential											
Module	**Sector**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Equipment	Residential	1.06	1.27	1.53	1.31	1.23	1.60	1.44	1.26	1.19	1.17	1.25	1.28	1.27	1.23	1.27	1.26	1.21	1.20	1.16	1.16	1.16
Equipment	Commercial	1.83	1.70	1.74	1.53	1.72	1.79	1.83	1.78	2.83	2.66	2.41	2.06	1.60	1.55	1.52	1.43	1.43	1.45	1.57	1.69	1.64
Equipment	Industrial	1.07	1.82	1.75	1.27	1.58	1.68	1.50	1.90	2.68	2.05	2.30	2.30	2.08	3.41	2.99	2.26	1.97	1.78	1.87	1.44	1.35
Measures	Residential	1.66	2.24	2.33	2.34	2.37	2.35	2.33	2.30	2.25	2.24	2.22	2.22	2.23	2.23	2.24	2.25	2.26	2.26	2.27	2.31	2.32
Measures	Commercial	2.14	2.16	2.18	2.17	2.12	2.15	2.14	2.13	2.12	2.13	2.11	2.13	2.15	2.14	2.13	2.09	2.02	1.82	1.39	0.83	0.48
Measures	Industrial	2.45	2.45	2.45	2.48	2.48	2.48	2.47	2.46	2.46	2.45	2.44	2.42	2.41	2.37	2.35	2.32	2.29	2.25	2.20	2.09	2.03
Equipment	All	1.13	1.62	1.71	1.50	1.66	1.76	1.78	1.72	2.66	2.48	2.26	1.95	1.56	1.53	1.50	1.41	1.40	1.40	1.49	1.57	1.52
Measures	All	1.80	2.26	2.33	2.35	2.37	2.37	2.35	2.33	2.30	2.29	2.28	2.27	2.28	2.26	2.26	2.26	2.25	2.22	2.19	2.14	2.11
All	All	1.65	1.88	1.96	1.89	2.02	2.07	2.06	2.02	2.50	2.39	2.27	2.10	1.89	1.87	1.85	1.80	1.79	1.78	1.81	1.83	1.79
											Economic Potential											
Module	**Sector**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Equipment	Residential	1.46	1.68	1.87	1.15	1.18	1.16	1.15	1.15	1.19	1.28	1.36	1.32	1.21	1.15	1.13	1.13	1.12	1.12	1.10	1.11	1.11
Equipment	Commercial	1.69	1.47	1.61	1.54	1.75	1.69	1.90	1.76	2.79	2.59	2.37	1.91	1.52	1.45	1.41	1.34	1.35	1.36	1.44	1.58	1.51
Equipment	Industrial	2.20	1.95	1.86	1.93	1.95	1.82	2.12	2.12	3.55	3.00	2.96	2.40	2.11	3.48	1.77	1.50	1.36	1.31	1.29	1.08	1.08
Measures	Residential	2.24	2.27	2.29	2.30	2.30	2.30	2.28	2.26	2.24	2.23	2.23	2.22	2.23	2.23	2.24	2.24	2.24	2.24	2.25	2.27	2.28
Measures	Commercial	2.11	2.08	2.11	2.15	2.16	2.15	2.14	2.12	2.12	2.12	2.13	2.13	2.15	2.14	2.13	2.08	1.97	1.69	1.17	0.67	0.43
Measures	Industrial	2.45	2.46	2.46	2.48	2.49	2.48	2.47	2.47	2.46	2.46	2.46	2.44	2.43	2.39	2.38	2.35	2.32	2.29	2.24	2.13	2.08
Equipment	All	1.65	1.55	1.69	1.45	1.61	1.57	1.75	1.65	2.54	2.37	2.20	1.81	1.47	1.45	1.36	1.30	1.29	1.31	1.35	1.45	1.39
Measures	All	2.22	2.24	2.26	2.30	2.31	2.30	2.29	2.28	2.27	2.26	2.26	2.26	2.26	2.25	2.25	2.23	2.20	2.13	1.99	1.86	1.79
All	All	1.84	1.76	1.88	1.79	1.92	1.92	2.01	1.95	2.41	2.32	2.23	2.02	1.85	1.84	1.79	1.75	1.73	1.70	1.66	1.65	1.59

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 1; Page No.: 1

QUESTION:

Using the same inputs, provide the same results (economic, market, achievable) assuming Manitoba Hydro was instead attempting to maximize savings at the same cost as avoided costs, i.e. so that the portfolio as a whole scored a B/C ratio of 1.

RESPONSE:

In Order 119/13 the PUB determined that it did not require this Information Request to be answered.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 1; Page No.: 1

QUESTION:

Same as above, but for a total B/C ratio of 1.25.

RESPONSE:

In Order 119/13 the PUB determined that it did not require this Information Request to be answered.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study

PREAMBLE: Baseline changes (codes and standards)

QUESTION:

Please provide a list of all anticipated codes and standards changes used in the study.

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

Sector	End Use	Fuel	Technology	Equipment	Label	Energy use relative to E1	On Market	Off Market
Residential	Interior Lighting	Electric	Screw-in	E1	Incandescent	100.0%	2010	**2013**
Residential	Interior Lighting	Electric	Screw-in	E2	Infrared Halogen	81.2%	**2014**	**2019**
Residential	Interior Lighting	Electric	Screw-in	E3	Infrared Halogen (2020)	31.5%	**2020**	2032
Residential	Interior Lighting	Electric	Screw-in	E4	CFL	22.3%	2010	2032
Residential	Interior Lighting	Electric	Screw-in	E5	LED	14.6%	2010	2032
Residential	Interior Lighting	Electric	Screw-in	E6	LED (2020)	7.2%	**2020**	2032
Residential	Interior Lighting	Electric	Linear Fluorescent	E1	T12	100.0%	2010	**2012**
Residential	Interior Lighting	Electric	Linear Fluorescent	E2	T8	73.8%	2010	2032
Residential	Interior Lighting	Electric	Linear Fluorescent	E3	Super T8	63.8%	2010	2032
Residential	Interior Lighting	Electric	Linear Fluorescent	E4	T5	61.4%	2010	2032
Residential	Interior Lighting	Electric	Linear Fluorescent	E5	LED	42.9%	2010	2032
Residential	Exterior Lighting	Electric	Screw-in	E1	Incandescent	100.0%	2010	**2013**
Residential	Exterior Lighting	Electric	Screw-in	E2	Infrared Halogen	89.4%	**2014**	**2019**
Residential	Exterior Lighting	Electric	Screw-in	E3	Infrared Halogen (2020)	34.7%	**2020**	2032
Residential	Exterior Lighting	Electric	Screw-in	E4	CFL	24.6%	2010	2032
Residential	Exterior Lighting	Electric	Screw-in	E5	LED	16.1%	2010	2032
Residential	Exterior Lighting	Electric	Screw-in	E6	LED (2020)	7.9%	**2020**	2032

Standards affecting screw-in lighting:

A standard goes into affect on January 1, 2014. This is represented by incandescent lamps going off market. Consumers may purchase infrared halogen, CFL and LED lamps instead.

Another standard goes into effect in 2020. This is represented by infrared halogen lamps going off market. Consumers may purchase infrared halogon (2020), CFLs or LED (2020).

Standard affecting linear fluorescent lighting:

A standard goes into affect on January 1, 2013. This is represented by T12 lamps going off market. Consumers may purchase T8, Super T8, T5 or LED lamps instead.

Sector	End Use	Fuel	Technology	Equipment	Label	Energy use relative to E1	On Market	Off Market
Commercial	Interior Lighting	Electric	Screw-in	E1	Incandescent	100.0%	2010	**2014**
Commercial	Interior Lighting	Electric	Screw-in	E2	90W Halogen PAR-38	73.7%	**2015**	**2020**
Commercial	Interior Lighting	Electric	Screw-in	E3	70W HIR PAR-38	59.5%	**2021**	2032
Commercial	Interior Lighting	Electric	Screw-in	E4	LED (2010)	18.0%	2010	2019
Commercial	Interior Lighting	Electric	Screw-in	E5	CFL	17.2%	2010	2032
Commercial	Interior Lighting	Electric	Screw-in	E6	LED (2020)	5.8%	**2020**	2032
Commercial	Exterior Lighting	Electric	Screw-in	E1	Incandescent	100.0%	2010	**2014**
Commercial	Exterior Lighting	Electric	Screw-in	E2	90W Halogen PAR-38	73.7%	**2015**	**2020**
Commercial	Exterior Lighting	Electric	Screw-in	E3	70W HIR PAR-38	59.5%	**2021**	2032
Commercial	Exterior Lighting	Electric	Screw-in	E4	LED (2010)	18.0%	2010	2019
Commercial	Exterior Lighting	Electric	Screw-in	E5	LED (2020)	5.8%	**2020**	2032
Commercial	Miscellaneous	Electric	Non-HVAC Motors	E1	Standard (EPAct)	100.0%	2010	**2014**
Commercial	Miscellaneous	Electric	Non-HVAC Motors	E2	Standard (EPAct 2015)	99.4%	**2015**	2032
Commercial	Miscellaneous	Electric	Non-HVAC Motors	E3	High Efficiency	98.7%	2010	**2014**
Commercial	Miscellaneous	Electric	Non-HVAC Motors	E4	High Efficiency (2015)	98.1%	**2015**	2032
Commercial	Miscellaneous	Electric	Non-HVAC Motors	E5	Premium (NEMA)	97.5%	2010	**2014**
Commercial	Miscellaneous	Electric	Non-HVAC Motors	E6	Premium (NEMA 2015)	96.8%	**2015**	2032
Commercial	Space Heating	Natural Gas	Boiler	E2	EF .80	95.0%	2010	**2014**
Commercial	Space Heating	Natural Gas	Boiler	E3	EF .82	92.7%	2010	**2014**
Commercial	Space Heating	Natural Gas	Boiler	E4	EF .85	89.4%	2010	2032
Commercial	Space Heating	Natural Gas	Boiler	E5	EF .96	79.2%	2010	2032
Commercial	Water Heating	Natural Gas	Water Heating	E2	EF .80	96.3%	2010	**2017**
Commercial	Water Heating	Natural Gas	Water Heating	E3	EF .94	81.9%	2010	2032

Standards affecting screw-in lighting:

A standard goes into affect on January 1, 2015. This is represented by incandescent lamps going off market. Consumers may purchase infrared halogen, CFL and LED lamps instead.

Another standard goes into effect in 2021. This is represented by infrared halogen lamps going off market. Consumers may purchase infrared halogon (2020), CFLs or LED (2020).

Standard affecting non-HVAC motors:

A standard goes into affect on January 1, 2015. This is represented by three motors going off market: Standard (EPAct), High Efficiency and Premium (NEMA).

Consumers may purchase three motors instead: Standard (EPAct 2015), High Efficiency (2015) and Premium (NEMA 2015)

Standard affecting natural gas space heating boilers:

A standard goes into affect on January 1, 2015. This is represented by EF .80 and EF .82 going off the market. Consumers may purchase boilers with EF .85 and EF .96 instead.

Standard affecting natural gas water heaters:

A standard goes into affect on January 1, 2018. This is represented by EF .80 going off the market. Consumers may purchase EF .94 instead.

Sector	End Use	Fuel	Technology	Equipment	Label	Energy use relative to E1	On Market	Off Market
Industrial	Interior Lighting	Electric	Screw-in	E1	Incandescent	100.0%	2010	**2014**
Industrial	Interior Lighting	Electric	Screw-in	E2	90W Halogen PAR-38	73.7%	**2015**	**2020**
Industrial	Interior Lighting	Electric	Screw-in	E3	70W HIR PAR-38	59.5%	**2021**	2032
Industrial	Interior Lighting	Electric	Screw-in	E4	LED (2010)	18.0%	2010	2019
Industrial	Interior Lighting	Electric	Screw-in	E5	CFL	17.2%	2010	2032
Industrial	Interior Lighting	Electric	Screw-in	E6	LED (2020)	5.8%	**2020**	2032
Industrial	Exterior Lighting	Electric	Screw-in	E1	Incandescent	100.0%	2010	**2014**
Industrial	Exterior Lighting	Electric	Screw-in	E2	90W Halogen PAR-38	73.7%	**2015**	**2020**
Industrial	Exterior Lighting	Electric	Screw-in	E3	70W HIR PAR-38	59.5%	**2021**	2032
Industrial	Exterior Lighting	Electric	Screw-in	E4	LED (2010)	18.0%	2010	2019
Industrial	Exterior Lighting	Electric	Screw-in	E5	LED (2020)	5.8%	**2020**	2032
Industrial	Heating	Natural Gas	Boiler	E2	EF .80	0.0%	2010	**2014**
Industrial	Heating	Natural Gas	Boiler	E3	EF .82	0.0%	2010	**2014**
Industrial	Heating	Natural Gas	Boiler	E4	EF .85	0.0%	2010	2032
Industrial	Heating	Natural Gas	Boiler	E5	EF .96	0.0%	2010	2032
Standards affecting screw-in lighting:								
A standard goes into affect on January 1, 2015. This is represented by incandescent lamps going off market. Consumers may purchase infrared halogen, CFL and LED lamps instead.								
Another standard goes into effect in 2021. This is represented by infrared halogen lamps going off market. Consumers may purchase infrared halogon (2020), CFLs or LED (2020).								
Standard affecting natural gas space heating boilers:								
A standard goes into affect on January 1, 2015. This is represented by EF .80 and EF .82 going off the market. Consumers may purchase boilers with EF .85 and EF .96 instead.								

REFERENCE: Appendix 4.3 Demand Side Management Potential Study.

PREAMBLE: Baseline changes (codes and standards)

QUESTION:

For each codes and standards change, provide details including: date of anticipated effective application, anticipated efficiency specifications before and after the change, context and/or description of anticipated change, and impact of change on potential.

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

Please see the response to CAC_GAC/MH I-012(a) for a list of the standards applied in the study. The impact of change on potential is outside the scope of this study.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 2; Page No.: 16

PREAMBLE: Price history and forecast

QUESTION:

Please specify what is the "price history and forecast" provided by Manitoba Hydro (2-16)? Is this the price of electricity sold in Manitoba?

RESPONSE:

The price history and forecast is the domestic rate history and forecasts for electricity and natural gas rates in Manitoba.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 2; Page No.: 16

PREAMBLE: Price history and forecast

QUESTION:

How was the "price history and forecast" used in the potential model?

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

The price history was not used in the model; it provides historical context. The price forecasts for each fuel, together with elasticities for each end use and fuel, were used to model changes in equipment utilization.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study.

PREAMBLE: EnerNOC's potential study

QUESTION:

On or around what date was the contract provided to EnerNOC?

RESPONSE:

The agreement between Manitoba Hydro and EnerNOC was signed on or around June 15, 2011.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study.

QUESTION:

On or around what date were the first draft results provided to Manitoba Hydro?

RESPONSE:

Manitoba Hydro received the results of the first model iterations in December 2012.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study

QUESTION:

On or around what date were the final draft results accepted by Manitoba Hydro?

RESPONSE:

The results received in the draft report dated July 11, 2013 were accepted by Manitoba Hydro. EnerNOC identified errors in some of the tables of this report and issued a revised report on August 31, 2013.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study

PREAMBLE: Data

QUESTION:

Please provide a complete list of baseline and efficient measures (technologies), with their respective energy consumption, cost, estimated useful life, and all other measure-level inputs used in the model.

RESPONSE:

This response is provided by EnerNOC Utility Solutions.

Please see Appendices B, C and D of the DSM Potential Study filed as Appendix 4.3 of this submission.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 2; Page No.: 13

PREAMBLE: Data

QUESTION:

Please provide the Manitoba Hydro's measure database in Excel format (2-13, line 4).

RESPONSE:

Please see attached link.

www.hydro.mb.ca/projects/development_plan/bc_documents/CAC_GAC.xls

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 2; Page No.: 16

PREAMBLE: Escalation rate

QUESTION:

Please explain the difference between the escalation rate and the adoption rates. Please provide the escalation rate (or rates) that was used in the potential study.

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

"Escalation rate" is a typographical error in the report. An escalation rate was not used in the model.

REFERENCE: Sept 6. Technical Conference

PREAMBLE: During the Technical Conference, Manitoba Hydro explained that the demand forecast is not affected by Manitoba Hydro's anticipated stream of rate increases.

QUESTION:

Please confirm that the load forecast implicitly assumes a price elasticity of demand equal to zero.

RESPONSE:

Please see Manitoba Hydro's response to PUB/MH I-256.

REFERENCE: Sept 6. Technical Conference

PREAMBLE: During the Technical Conference, Manitoba Hydro explained that the demand forecast is not affected by Manitoba Hydro's anticipated stream of rate increases.

QUESTION:

Please provide new load forecast results (including low, medium and high) assuming price elasticities of demand of -0.2 for the short run (1-5 yrs.) and -1.0 for the long run (and assuming Manitoba Hydro's best or most recent estimate of anticipated annual rate increases throughout the NFAT period).

RESPONSE:

Please see the table below. The 2013 load forecast filed as Appendix D was not prepared using low, medium and high scenarios. As indicated at page 44 of Appendix D, the 10% and 90% confidence bands were selected to be a proxy for the Low and High Load Forecast Scenarios.

The load forecast results in the table below were produced by incorporating price elasticity as an explicit variable, and have been run using the price elasticities provided in the question. Manitoba Hydro notes that there is no evidence to support the applicability of the short run elasticity of -0.2 nor the long run elasticity of -1.0 in the Manitoba market.

Fiscal Year	Base Forecast With Price Effect	10% Prob With Price Effect	90% Prob With Price Effect
2013/14	25150	24787	25512
2014/15	25488	24935	26040
2015/16	25724	25018	26430
2016/17	25930	25089	26772
2017/18	26110	25146	27075
2018/19	26032	24967	27096
2019/20	25917	24763	27070
2020/21	25794	24560	27029
2021/22	25682	24374	26990
2022/23	25565	24189	26941
2023/24	25443	24004	26882
2024/25	25314	23817	26811
2025/26	25181	23630	26731
2026/27	25042	23443	26642
2027/28	24898	23252	26543
2028/29	24762	23074	26450
2029/30	24620	22893	26347
2030/31	24473	22710	26236
2031/32	24317	22521	26114
2032/33	24158	22331	25986

REFERENCE: Sept 6. Technical Conference

PREAMBLE: During the Technical Conference, Manitoba Hydro explained that the demand forecast is not affected by MH's anticipated stream of rate increases.

QUESTION:

Please provide Manitoba Hydro's best estimates of short run and long run price elasticities of demand for the Manitoban market.

RESPONSE:

Please see Manitoba Hydro's response to PUB/MH I-256.

REFERENCE: Business Case

PREAMBLE: Integrated resource planning

QUESTION:

When was the last time Manitoba Hydro conducted a resource planning exercise, directly comparing investment in DSM with new generation options?

RESPONSE:

The last time Manitoba Hydro conducted a resource planning study that evaluated DSM as a competing option to new generation options was for the 2001 Power Resource Plan (report PP&O #01-05, November 2001).

Manitoba Hydro conducted a DSM Market Potential Study in 2003/04 which was consequently used as the basis for increasing the DSM plans for the 2004/05 and 2005/06 Power Resource Plans. Around this time, Manitoba Hydro's marginal cost was primarily derived from the export value of increased electricity sales. DSM opportunities were subsequently assessed based on the incremental value associated with selling the conserved energy in the export market relative to using and selling the electricity in the domestic market.

The DSM assessment was undertaken by using the Levelized Utility cost (LUC) and Rate Impact Test (RIM) of conserved energy and undertaking a general comparison to the difference between Manitoba Hydro's marginal cost and domestic rates. The use of RIM was essential in the assessment due to the timing differentials in Manitoba Hydro's marginal cost (i.e. energy conserved during the winter season had a higher value to Manitoba Hydro compared to energy conserved during the summer). All DSM opportunities which provided an economic benefit were pursued.

REFERENCE: Business Case

QUESTION:

Why wasn't this approach used for the current NFAT hearing?

RESPONSE:

This approach was not used for the current NFAT filing for two reasons:

1) Unlike most other jurisdictions who are studying the appropriate level of DSM, in the Manitoba Hydro situation the main economic benefit from increasing DSM arises not from increased DSM deferring generation but from increased DSM increasing the level of exports. In Manitoba Hydro's situation, there typically are economic benefits from advancing generation and economic losses from deferring generation. Thus evaluating DSM by studying it as competing with new hydro generation and deferring that generation would have the perverse outcome of negatively affecting the economics of the DSM. An appropriate approach to evaluate DSM in such a situation is to determine the increase in generation system operation benefits associated with increasing the exports resulting from the higher levels of DSM. Manitoba Hydro has been using this approach for the past number of years in determining the marginal values which then provides a reasonably representative indication of the generation benefits of the DSM. Such marginal values were utilized to develop the DSM Plan utilized in the submission.

2) Recognizing that there would be much attention to DSM in the NFAT process, Manitoba Hydro had intended to undertake a full DSM Market Potential Study and then utilize the resulting information to perform an evaluation of DSM utilizing different levels of DSM in conjunction with different generation plans and exports. Unfortunately the DSM Market Potential Study took much longer to complete than expected and planned. As a result, the generation plan evaluations with the different levels of DSM could not be undertaken in time for the August 16, 2013 filing of the NFAT submission required by the NFAT schedule. However, the DSM Market Potential Study was able to be completed in time

for inclusion in the submission. Manitoba Hydro has indicated it intends to undertake prior to the NFAT hearing a generation plan study with two levels of DSM but this would depend on the amount of time required by Manitoba Hydro Staff to respond to interrogatories.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 2; Page No.: 16

PREAMBLE: Adoption rates: Enernoc provided the adoption curves used by Northwest Power and Conservation Council. Then Manitoba Hydro “adjusted them” to reflect Manitoba’s context.

QUESTION:

Please provide the adoption rates from the Northwest Power & Conservation Council and the adjusted adoption rates that were used in the potential study for each measure where such an adjustment has been made.

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

The following table outlines the Sixth Plan Ramp Rates from the Northwest Power & Conservation Council. These rates were used as a starting point for developing the Manitoba market acceptance rates (MARs). The Council assigns the handful of ramp rates shown below to individual measures in its measure workbooks. The measures used by the Council in its plan are different than the measures that EnerNOC uses in its potential studies.

For example, the Council includes many lamp wattages in its workbooks for residential screw-in lighting. In contrast, EnerNOC uses a single lamp wattage to represent interior screw-in lighting.

An excerpt from the Council’s mapping of their ramp rates to measures is shown below the ramp rate table.

Attached is a file outlining the Market Acceptance Rates (MARs) used for calculating Market Potential, and Program Implementation Factors (PIFs) and the MAR times PIF factor used for calculating Achievable Potential from the Manitoba Hydro study. Tables are provided for each sector, fuel and measure type (equipment and non-equipment measures). For more information on the use of these factors please refer to the response to PUB/MH-0261.

As the measures used by the Council are different than those used in EnerNOC's study, to respond to this question and identify each measure where an adjustment was made cannot be undertaken in the timeframe of this proceeding given the level of measure detail as evidenced by the attached file.

Sixth Plan Ramp Rates from the Northwest Power & Conservation Council:

Commercial		**Sixth Plan Conservation Supply Curves, Commercial, Com_**							http://www.nwcouncil.org/energy/powerplan/6/supplycurves/default.htm													
Fraction of Applicable Measure Available by Year																						
Label	**Description**	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21
LO Mature	Lost opportunity mature measure	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
LO Fast	Lost opportunity fast pace	20%	40%	60%	80%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
LO Medium	Lost opportunity medium pace	10%	20%	30%	40%	50%	60%	70%	80%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%	85%
LO Slow	Lost opportunity slow pace	5%	10%	15%	20%	25%	30%	35%	40%	45%	50%	55%	60%	65%	70%	75%	80%	85%	85%	85%	85%	85%
LO 20Fast	Lost opportunity ??? Pace	19%	33%	45%	54%	61%	66%	70%	73%	76%	78%	80%	81%	82%	82%	83%	83%	84%	84%	84%	84%	85%
LostOp_ComComputer	Lost opportunity commercial computer	1%	2%	3%	5%	8%	11%	15%	19%	23%	29%	34%	40%	45%	51%	57%	62%	68%	74%	79%	85%	85%
LostOp_ComMonitor	Lost opportunity commercial monitor	1%	2%	3%	5%	8%	11%	15%	19%	23%	29%	34%	40%	45%	51%	57%	62%	68%	74%	79%	85%	85%
Retro in 20	Retrofit over 20 years	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
Retro in 10	Retrofit over 10 years	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%	10%

Residential		**Source: Sixth Plan Conservation Supply Curves, Residential, PNWResDHWLight&ApplianceCurve_6thPla**													http://www.nwcouncil.org/energy/powerplan/6/sup							
Year		**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	21
Ramp Type		**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Annual Market Penetration																						
Label	**Description**																					
LostOp_5yr	Lost opportunity - 5 year	2.6%	3.5%	4.4%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%	5.3%
LostOp_10yr	Lost opportunity - 10 year	2.7%	3.2%	3.8%	4.3%	4.9%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%	5.4%
LostOp_12yr	Lost opportunity - 12 year	1.7%	2.3%	2.9%	3.5%	4.1%	4.7%	5.2%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%	5.8%
LostOp_15yr	Lost opportunity - 15 year	1.2%	1.8%	2.4%	3.0%	3.7%	4.3%	4.9%	5.5%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%	6.1%
LostOp_20yr	Lost opportunity - 20 year	0.6%	1.3%	1.9%	2.6%	3.2%	3.9%	4.5%	5.2%	5.8%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%
LostOp_EmergTech	Lost opportunity - emerging tech	0.10%	0.20%	0.45%	0.70%	1.00%	1.30%	1.6%	1.9%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%	7.7%
NonLostOp_10yr	Non lost opportunity - 10 year	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
NonLostOp_15yr	Non lost opportunity - 15 year	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	6.7%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
NonLostOp_20yr	Non lost opportunity - 20 year	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%	5%
NonLostOp_5yr	Non lost opportunity - 5 year	20%	20%	20%	20%	20%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%

Examples of Sixth Plan EE measures and corresponding ramp rates:

Sixth Plan EMeasure	**Corresponding Sixth Plan Ramp Rate**
Existing SF HVAC Updgrade to HSPF 9.0/SEER 14 Heat Pump	LostOp_20yr
Energy Star Window Air Conditioner	LostOp_10yr
EF- 0.94 Domestic Water Heater	LostOp_10yr
High Efficiency Dryer	LostOp_12yr
Energy Star Dishwasher (EF68)	LostOp_10yr
Energy Star Refrigerator	LostOp_20yr
Self-Cleaning Oven	LostOp_20yr
Microwave Oven	LostOp_10yr
ResComputer	LostOp_ResComputer
ResTV	LostOp_ResTV
Res Set Top Box	LostOp_ResSTB
Single Family Weatherization	NonLostOp_15yr
Showerhead Replacement in Residential Dwellings - Any Showerhead, Electric DHW	NonLostOp_5yr

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 2; Page No.: 16

QUESTION:

For each measure that has had its adoption rate adjusted, please provide the rationale for such an adjustment.

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

It is EnerNOC's typical practice to use a set of publicly available adoption rates for each study as the starting point for a potential study[1]. These starting values are adjusted in consultation with the clients' program managers, to align with past program participation.

For this study, EnerNOC started with the Northwest Power and Conservation Council's "ramp rates" which are categorized according to measure type. These measure types were mapped to individual measures in the Manitoba Hydro study and used as starting values for the MARs (Market Acceptance Rates). Then, working with Manitoba Hydro program staff, the MARs were adjusted to reflect best-case participation by customers in Manitoba Hydro programs. Then, these MARs were used as the starting point for development of participation rates that reflect Achievable Potential. This step relied heavily on Hydro program experience but also referred to participation rates that EnerNOC has used for other studies. This process involved judgment, as is required in all potential studies.

Manitoba Hydro's Response:

[1] The exceptions to this rule are the studies we performed for Ameren Corporation. They have undertaken extensive market research with their own customers to develop take rates for EE programs. We use these values for market adoption in the first program year and we escalate them at 1% per year throughout the study time horizon.

To review and document all changes made to the adoption rate of each technology included in the Demand Side Management Potential Study cannot be reasonably completed within the timelines of this proceeding as the combination of measures and market segments results in a requirement to review over 15,000 data records (please refer to the response to CAC/GAC/MH I-019 a).

In general, adjustments were made to adoption rates to reflect the following types of Manitoba specific conditions:

- Technical limitations as a result of differences in climate. For example, CFL lighting performs poorly in exterior applications during winter in Manitoba. In consideration of this issue, CFLs for this application has not been aggressively promoted, resulting in a low adoption rate in Manitoba. Climate also creates seasonal limitations in industry's ability to perform work; for example limited major building envelope projects and limited ability for drilling for geothermal in winter.
- Local codes and standards. Due to the potential for bacteria growth in hot water tanks, the Manitoba Plumbing Code stipulates a minimum tank temperature that precludes hot water thermostat setback. This measure has been removed from residential potential in order to comply with the code.
- Participation rates in current and previously offered programs. For example, insulation potential was reduced by the number of households that have already insulated under the existing program, as these homes will not be insulated again.
- Manitoba Hydro's past experience with adoption rates. For example, the adoption rates for insulation upgrades in the Education sector in Manitoba was increased due to this specific sector's historic willingness to invest in energy efficiency.

- Regional market readiness and industry capacity differences. For example, the adoption rates for Advanced New Construction Designs were increased due to a growing local industry offering consulting services necessary to support high performance building construction.
- Differences in adoption rates of select technologies across different segments. The factors that differ across sectors include but are not limited to: size of building, vintage of building, hours of use, and occupancy levels, which all may impact adoption rates. For example, the adoption rates for high efficiency motors and variable speed controls for pumps were reduced for specific sectors to reflect that smaller and one-storey buildings are less likely to require this equipment. As well, the adoption rates for Energy Management Systems were reduced for specific sectors to reflect that smaller and less complex facilities are less likely to install an Energy Management System due to the fact that manual operation of controls is simpler and less complex.

REFERENCE: Appendix 7.1 Emerging Energy Technology Review; Page No.: 44

PREAMBLE: In MH's evidence (Appendix 7.1, page 44), the cost of utility-scale solar PV is expected to decline to $0.65/watt by 2020.

QUESTION:

What is the reasonable expectation for further years, e.g. 2025 and 2030?

RESPONSE:

As provided in Appendix 7.2 on page 20 of 367, a decline in the cost of utility-scale solar PV installations consistent with the current trend of an annual reduction of 8%, would result in the installed cost of fixed tilt solar PV reaching $1.93/Watt by 2020 and $0.84/Watt by 2030. There is uncertainty in the current trend continuing as, in addition to the reduction in solar module price, which is largely based on technological advancements, a significant reduction in the balance of plant component costs (typically the civil and electrical works and related labour) is also required. As a result, Manitoba Hydro assumed the current cost of $3.75/watt in the screening process.

A reduction in the installed cost of a utility scale fixed tilt solar PV installation to $0.65/watt by 2020 is considered very optimistic. As indicated in Appendix 7.1, a significant decline in solar costs would require significant improvements in efficiency of solar modules and continuous module price declines with increasing demand and production. A significant assumption in the projected solar module efficiency improvements is the realization of technological advancements such as implementation of nano materials which have currently only been demonstrated in the laboratory and not on a commercial or utility scale. In addition, while some industry activity has been directed towards the development of automated systems for installation and cleaning of panels, there is currently an increasing trend in costs related to civil and electrical works and related labour.

REFERENCE: Appendix 7.1 Emerging Energy Technology Review; Page No.: 44

QUESTION:

Given southern Manitoba's solar radiation as reported in Manitoba Hydro's evidence (1300-1400 kWh/kW – see p. 48), and using Manitoba Hydro's cost of capital and reasonable useful lives of PV systems (generally assumed as either 25 or 30 years), please indicate the anticipated $/kWh cost of solar PV installed in 2020.

RESPONSE:

The following tables provide a range of levelized costs of electricity for a utility scale fixed-tilt solar PV installation based on the information provided in the NFAT filing. Integration and interconnection costs are not available and have not been included in the levelized cost calculations. A capacity factor of 20% is representative of a utility scale PV installation in Manitoba.

Please also see Manitoba Hydro's response to CAC_GAC/MH I-0020a) for additional context for these solar PV costs.

Using an optimistic reduction in installed cost to 2020 ($0.65/Watt):

Criteria	Fixed Tilt
Plant Size	> 10 MW
Plant Life	20 years
Discount Rate	5.05%
Capacity Factor	20%
Installed Cost (2012$/MW)	$650,000/MW
Operation & Maintenance	$19,700/MW/Year
Real Escalation	0%
Levelized Cost Of Electricity (2012$/MW.h)	$41.70 MW.h

Using annual 8% reduction in installed cost to 2020 ($1.93/Watt):

Criteria	Fixed Tilt
Plant Size	> 10 MW
Plant Life	20 years
Discount Rate	5.05%
Capacity Factor	20%
Installed Cost ($2012/MW)	$1,930,000/MW
Operation & Maintenance	$19,700/MW/Year
Real Escalation	0%
Levelized Cost Of Electricity ($2012/MW.h)	$100.50 MW.h

The levelized cost of a fixed tilt solar PV installation as provided in Appendix 7.2 of the NFAT Business Case based on an installed cost of $3.75/Watt is $203 (2012$)/MW.h. As discussed in CAC_GAC/MH I-020a), while there are various projections indicating a reduction in the cost of solar PV installations in the future, there is considerable uncertainty in the achievability of these cost reductions.

It should be noted that levelized cost of energy does not indicate the value of the generation but is a relative measure of the cost associated with a unit of energy. In the NFAT analysis, levelized cost was used as one of the factors considered in an initial high level of screening of resource options.

REFERENCE: Appendix 7.1 Emerging Energy Technology Review; Page No.: 44

QUESTION:

Given PV's intermittency, what is Manitoba Hydro's assumption about the incremental cost of capacity?

RESPONSE:

Manitoba Hydro has not evaluated the incremental cost of capacity to support a solar PV installation.

REFERENCE: Appendix 7.1 Emerging Energy Technology Review; Page No.: 44

QUESTION:

If the forecast is correct, and integrating the assumed cost of additional capacity in 2020, what would be the $/kWh cost of utility-scale solar PV combined with sufficient capacity to offset its intermittency, i.e. to provide a service similar to hydro or gas plants?

RESPONSE:

Manitoba Hydro does not have the levelized cost information requested in this Information Request. As indicated in the response to CAC_GAC/MH I-020c, Manitoba Hydro has not evaluated the incremental cost of capacity required to support a solar PV installation.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 4; Page No.: 3

PREAMBLE: Residential miscellaneous.

QUESTION:

Please confirm that the "Miscellaneous Technology" category of the "Miscellaneous End Use" (Table 4-1, p. 4-3) will represent more than 10% of the residential baseline electricity forecast (962 GWh / 8,831 GWh) by 2031/2032.

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

Confirmed.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 4; Page No.: 2

PREAMBLE: Residential miscellaneous.

QUESTION:

According to point 5 on page 4-2, the miscellaneous use consists of various plug loads including hair dryers, power tools and coffee makers. This description doesn't help to understand why it is constituting such an important part of the total residential load in 2031/2032. Please be more specific in your description and provide a breakdown of this load.

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

In the base year (2010/2011), the miscellaneous load includes hair dryers, power tools and other miscellaneous plug loads. During the forecast period, this end use includes growth in the aforementioned plug loads and all new future uses of electricity. The end uses are not yet known, but based on history it is expected that they will add significantly to overall electricity use.

For example, in the past energy use for consumer electronics (PCs, TVs, etc.) were small and were included in the miscellaneous end use. When these appliances and devices proliferated in the 1990-2005 timeframe, their energy use increased substantially. At present, consumer electronics are broken out of miscellaneous and are forecast separately. It is expected that something similar will happen in the future.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 4; Page No.: 3

PREAMBLE: Residential miscellaneous.

QUESTION:

What are the technical, economic, market and achievable energy efficiency potentials associated with this load (in % of the 962 GWh forecasted load).

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

The study does not include any potential future savings from this load. Since it is not known what new uses will drive the growth, it is not appropriate to make any assumptions about efficiency measures that can offset the growth. In the recent past, referring again to TVs, there was a substantial increase in TV penetration, particularly from flat-screen TVs. The early flat-screen TVs used a lot of electricity and this raised concerns in the industry. Within a few years, PG&E, the U.S. EPA and other government agencies and organizations worked with manufacturers to reduce energy consumption of TVs, resulting in much more efficient TVs for sale today. The degree of increase in load and the respective EE reduction could not have been specifically predicted.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 4; Page No.: 5

PREAMBLE: Commercial miscellaneous.

QUESTION:

Please confirm that the "Miscellaneous Technology" category of the "Miscellaneous End Use" (Table 4-3, p. 4-5) will represent more than 10% of the commercial baseline electricity forecast (601 GWh / 5,655 GWh) by 2031/2032.

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

Confirmed.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 4; Page No.: 5

PREAMBLE: Commercial Miscellaneous.

QUESTION:

Please provide a description of what constitutes this load and a breakdown of the most important technologies/uses.

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

In the base year (2010/2011), this load includes all types of miscellaneous plug loads in commercial buildings that are not elsewhere captured by the end use technologies presented in the table. In all commercial segments it includes water coolers, coffee makers, microwave ovens, power tools, TVs, etc. In the health segment, it also includes medical equipment. In the future, it will include growth in these loads as well as other new uses of electricity.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 4; Page No.: 5

PREAMBLE: Commercial Miscellaneous.

QUESTION:

What are the technical, economic, market and achievable energy efficiency potentials associated to this load (in % of the 601 GWh forecasted load).

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

Please see the response to CAC_GAC/MH I-021c.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 4; Page No.: 5

QUESTION:

Please explain why this load almost triples over the period considered (2010/11 - 2031-32) while the total commercial load is flat during the same period.

RESPONSE:

Please see the response to PUB/MH I-248.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 5; Page No.: 2

PREAMBLE: Energy efficiency measures

QUESTION:

From Table 5-1, it is not clear if the efficient geothermal heat pumps (COP 3.3+) can be applied to a portion of the whole market (including standard furnaces and boilers) or only to existing geothermal heat pumps. Please provide further explanation on the potential market for this technology.

RESPONSE:

Efficient geothermal heat pumps were applied to a portion of the whole market; specifically to residential single-family homes with electric furnaces. Of this subset, the homes in northern Manitoba (North-No-Gas segment) tend to have a lower propensity to switch due to low saturation of air conditioning and higher capital cost for remote installations, therefore a higher incremental cost was used in the northern subset of single detached homes. For homes in southern Manitoba (South-Gas, South-No-Gas, and Winnipeg Segments), an average incremental cost was used to model geothermal heat pumps. However, this cost does not reflect the cost effectiveness assessment for smaller homes or homes with baseboard heating, electric boilers, or existing heat pumps systems, where due to reduced savings or increased associated conversion costs mean the systems are not cost effective for the entire segment. These factors along with land size in urban settings, geological conditions, and lower natural gas prices were considered for the market acceptance of this technology.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 5; Page No.: 2

QUESTION:

Please confirm that heat pump water heaters have not been included for either the residential or the commercial sector. Please explain why.

RESPONSE:

Residential heat pump water heaters were excluded from the study as they are not suited to the Manitoba climate. In Manitoba, hot water heaters are located in a conditioned space. Heat pump water heaters produce cooler air within the space as they extract heat to transfer to the water heater. The extracted heat must then be made up by the building's heating system. Commercial heat pump water heaters were included in the study but did not make it through cost effectiveness screening.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 5; Page No.: 6

QUESTION:

Why was the drainwater heat recovery measure excluded from the existing market?

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

The drainwater heat recovery measure was excluded from the existing market in error. EnerNOC estimates that including the measure for existing homes would increase cumulative energy savings in 2031/32 for Achievable Potential from 7.7 GW.h to 9.1 GW.h and Market Potential from 16.6 GW.h to 19.5 GW.h for drainwater heat recovery.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 5; Page No.: 6

QUESTION:

Please provide a breakdown of residential buildings in Manitoba according to the type of basement (slab, crawlspace, full height basement…) per building type (single family, multifamily…).

RESPONSE:

Based on the 2009 Residential Survey, the breakdown of the total numbers of Residential basement types by dwelling types are as follows:

Dwelling Type	No Basement	Full Basement	Partial Basement	Crawl Space
Single Detached	22,860	280,237	26,644	20,158
Multi-Attached	5,845	21,713	2,124	3,642
Apartment Suite	55,873	0	0	0
Total Province	**84,578**	**301,950**	**28,768**	**23,800**

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 5; Page No.: 6

QUESTION:

For full height basements, please provide the number of basements that are a) unfinished, b) partly finished, or c) fully finished.

RESPONSE:

Based on the 2009 Residential Energy Use Survey, the breakdown of the total number of Residential insulation finishes for full height basements are as follows:

Insulation Level	Number of Full Basements
Not Insulated	29,114
10%-49%	16,013
50%-89%	60,987
90%-100%	169,922
Do Not Know	25,914
Total Full Basements	301,950

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 5; Page No.: 8

PREAMBLE: Energy Efficiency Measures.

QUESTION:

Please explain the difference between the "LED 2010" and "LED 2020" measures in terms of costs, efficiencies and other characteristics. Why isn't there a "LED 2013 (current)" measure?

RESPONSE:

This response is provided by EnerNOC Utility Solutions.

At the time of the analysis, information from a Navigant study was used for two lamps: LED and LED 2020. The LED 2020 is a new technology expected to be available starting in 2020 that is twice as efficient and costs about one third as much as the LED 2010 lamp. The report used was *EIA – Technology and Forecast Updates – Residential and Commercial Building Technologies – Reference Case*, Navigant Consulting, September 2008.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study

PREAMBLE: Energy efficiency potentials

QUESTION:

Please provide the usual ranges of Technical, Economic, Market and Achievable potentials for comparable markets, expressed as a percentage of load forecast, both for 10 yrs and 20 yrs spans where available.

RESPONSE:

The following response is provided by EnerNOC Utility Solutions.

EnerNOC reviewed their recent studies and compiled the ranges of potential estimates for the four types in the table below. Studies from the Northeast, Midwest, Southwest and Southeast regions of the U.S. have been included in the table. The high end of the range comes from studies in the Pacific Northwest that categorize naturally-occurring conservation as part of the potential savings rather than having naturally occurring conservation included in the baseline There were more studies with results on the lower end of the spectrum than at the high end.

Manitoba values in the table below reflect revised potential levels as outlined in the response to PUB/MH I-248.

Potential Level	After 10 years			After 20 years		
	Manitoba	Low	High	Manitoba	Low	High
Technical	24%	13%	32%	30%	20%	30%
Economic	19%	10%	21%	25%	14%	25%
Market	11%	7%	15%	16%	11%	20%
Achievable	5%	4%	9%	8%	6%	11%

REFERENCE: Appendix 4.3 Demand Side Management Potential Study

QUESTION:

Why is the Achievable potential so low in Manitoba? What are the main barriers specific to the Manitoban market that can explain such a result?

RESPONSE:

Referring to the table provided in Manitoba Hydro's response to CAC/GAC/MH I-024(a), Manitoba's potential is within the range for all levels of potential.

For Achievable potential, Manitoba is within the range, although toward the lower end. Manitoba's potential differs by sector and considers several influencing factors.

At the sector level, as outlined in Manitoba Hydro's response to CAC/GAC/MH I-025(a), a few significantly large industrial consumers are considered mature from a DSM perspective or known to be near phase-out, both circumstances will reflect lower potential.

Manitoba's lower energy rate as compared to other jurisdictions will also create additional barriers specific to customers in Manitoba particularly with commercial and industrial customers where ROI and payback results are important criteria for decisions related to investments in energy efficiency as these projects compete with other projects for capital resources including projects at facilities in other jurisdictions.

Another consideration is that Manitoba is in a heat load dependant jurisdiction and the efficiency of electric heating systems is generally considered a high or fixed efficiency measure and any beneficial impacts associated with implementation of high efficiency improvements would be decreased or offset by the “interactive effects” relating to heating. This leads to the understanding that Manitoba can have a significant electrical consumption index and still be very efficient. In addition, some traditional energy efficiency measures used in other jurisdictions are not suitable to Manitoba application (e.g. exterior CFL, air to air heat pumps, etc), and tend to reflect potential toward the lower end of range.

Strategies to address market barriers are currently being considered as Manitoba Hydro undertakes to update the Corporation’s Power Smart Plan, in consultation with the Minister of Innovation, Energy and Mines and responsible for Manitoba Hydro as directed in The Manitoba Energy Savings Act, by March 31, 2014.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study;

PREAMBLE: Energy efficiency potentials

QUESTION:

In assessing the Market and Achievable potentials, have you considered the possibility of new regulations, codes and standards that would go beyond the "Business as Usual" forecast?

RESPONSE:

Market Potential assesses the subset of economic potential that can be obtained through market intervention under ideal market, implementation, regulatory and customer preference conditions; efforts are supported by focused and coordinated efforts across governments, utilities and industry to eliminate all material market barriers. For the purpose of assessing the market potential, the only barrier is assumed to be customer preferences for the technology or measure. While specific strategies to move towards this ideal market were not discussed, it is implied that strategies beyond the “business as usual” would be required.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study;

PREAMBLE: Energy efficiency potentials

QUESTION:

In assessing the Market and Achievable potentials, have you considered the possibility of introducing new enabling strategies?

RESPONSE:

Please see Manitoba Hydro's response to CAC_GAC/MH I-024(c).

REFERENCE: Appendix 4.3 Demand Side Management Potential Study;

QUESTION:

In assessing the Market and Achievable potentials, have you considered the possibility of using rate structures to promote energy efficiency?

RESPONSE:

See Manitoba Hydro's response to GAC/MH I-029d

The following response was provided by EnerNOC Energy Solutions.

Depending upon design, rate structures may encourage increased participation in energy efficiency; however, the impacts of alternative rate designs were not specifically modeled in assessing Market and Achievable potentials. The scope of the study was the analysis of energy-efficiency measures for which the LoadMAP modeling framework is well suited. Estimation of alternative rate-design impacts requires an analysis approach specifically designed for this purpose.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 6; Page No.: 20

PREAMBLE: Industrial sector potential: Industrial processes represent more than half of the industrial load (4,741 GWh / 9,304 GWh in 2031/2032). However, they account for only 14% of the economic potential.

QUESTION:

Please confirm that a large share of the energy efficiency potential for industrial processes is not assessed by the potential study because site-specific opportunities are not assessed. What is the load forecast for industrial processes that are out of scope?

RESPONSE:

A large share of the energy consumption related to Manitoba's industrial processes has been minimized or considered "saturated" in the scope of the study. The majority of energy use in the industrial sector is consumed by a small number of customers. For example, the mining and chemical industries use approximately 60% of the total industrial energy consumption. Of those industries, six customers make up 90% of the energy use in their segment (or 50% of the total industrial sector). The chemical industry makes up a significant portion of process energy use within industrial. It is understood that the DSM savings achieved for the Chemical sector in Manitoba, dominated by two large companies which have participated in Manitoba Hydro's Power Smart Performance Optimization Program for industrial businesses, should be considered mature and transformed for the DSM planning period. It is also understood that the processing elements associated with the large mining companies is considered as mature with a large portion being scheduled for phase-out. The ancillary motive load related to any recurring process load would be identified and pursued as part of the Manitoba Hydro program that supports facility screening and feasibility studies. At the planning level it was the author's choice to assume the residual process savings as immaterial and have a conservative estimate rather than include a small value with little supportable tie to the Manitoba market.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 6; Page No.: 20

PREAMBLE: Industrial sector potential: Industrial processes represent more than half of the industrial load (4,741 GWh / 9,304 GWh in 2031/2032). However, they account for only 14% of the economic potential.

QUESTION:

For what reason(s) were the site-specific opportunities excluded from the scope of the potential study?

RESPONSE:

Looking at the largest customers who make up the majority of the industrial process energy use, as outlined in Manitoba Hydro's response to CAC_GAC/MH I-025(a), significant upgrades which would provide potential energy savings potential are not foreseen in the period of the study potential. The opportunity for economically viable energy conservation measures for site-specific industrial process equipment is during upgrades and replacement cycles. The cost associated with changing out site-specific process equipment can not generally be justified solely on energy savings alone.

Any load expansions or major refurbishments that are not specifically foreseen in the load forecast would most likely have relatively insignificant DSM potential due to the generally higher base cases associated with new processes.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 6; Page No.: 20

PREAMBLE: Industrial sector potential: Industrial processes represent more than half of the industrial load (4,741 GWh / 9,304 GWh in 2031/2032). However, they account for only 14% of the economic potential.

QUESTION:

Wouldn't it be possible to assess the potential for these processes at a high level even if site-specific studies are not conducted? In your knowledge, what are the usual approaches used to assess potentials for industrial processes in other potential studies?

RESPONSE:

The approach taken was to use a global or North American performance metric as an initial base case. An issue with using general industrial process metrics that are derived from national data or US data is that they may differ greatly from industry process potential in Manitoba that is dominated by a few large facilities, a significant portion of which is considered to be mature from a DSM perspective or known to be near phase-out. In this instance, Enernoc began with Pacific Northwest's data and modified from it there to suit available information about the Manitoba industrial load.

Any remaining or residual process-driven savings potential, net of their ancillary loads that are already captured in the motive load measures, will be included in actual program implementation when qualified on a case by case basis during any site specific assessment.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 6; Page No.: 20

PREAMBLE: Industrial sector potential: Industrial processes represent more than half of the industrial load (4,741 GWh / 9,304 GWh in 2031/2032). However, they account for only 14% of the economic potential.

QUESTION:

Are there any other industrial end-uses that could be negatively affected by this decision to exclude site-specific assessments? Please specify the end-uses and the associated 2031/32 load forecasts.

RESPONSE:

In our opinion there would be no negative effects to other industrial end-uses as those ancillary motive loads are captured in their respective end-use elements of the potential study.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study; Section: 6; Page No.: 20

PREAMBLE: "...opportunities to capture these types of process savings are tied directly to specific industry business cycles within each industry sector that dictates major events such as equipment change-outs, plant overhauls, facility expansions, and new plant construction. These cycles are periodic, can stretch across decades and are therefore more difficult to project the size and timing as an energy efficiency opportunity. As a result, in 2031/32, Achievable potential is 250 GWh or 2.7% of the baseline industrial forecast."

QUESTION:

Given that the potential study also stretches over decades (up to 2032), encompassing multiple business cycles, please explain why periodic cycles should have an impact on the Achievable potential.

RESPONSE:

It is expected that periodic cycles will be fully reflected in the realization of the Achievable Potential stated in the DSM Potential Study over several decades. While these periodic cycles have the potential to provide significant incremental savings to Manitoba Hydro, the timing of these investments, which typically represent significant and large capital expenditures for the renewal of facilities and process infrastructure by Manitoba Hydro customers, are not always predictable due to externalities that are beyond the control of the utility. Externalities such as the prevailing economic climate, competitive market conditions, market price and demand predictions, and maintenance/replacement cycles all play a substantive role in the timing of these investments.

REFERENCE: Appendix E 2013- 2016 Power Smart Plan.

PREAMBLE: Power Smart Plan.

QUESTION:

For each program in the Power Smart Plan, please provide: a) an estimate of the total potential market for the promoted measures, b) the penetration (% of participation on total potential) achieved to date by the programs, and c) the additional penetration that is forecasted to be achieved over the next three years.

RESPONSE:

The following presents the market penetration details for each program as presented in the 2013 – 2016 Power Smart Plan.

Commercial Lighting Program

1) The total potential market is estimated to be 52,500 lighting projects.
2) Through to the end of fiscal 2012/13, there have been 12,379 lighting projects thus reaching a current market penetration of 24% (12,379 ÷ 52,500).
3) Over the next three years, 2,151 additional lighting projects are forecast, thus an additional 4% penetration (2,151 ÷ 52,500), equating to total cumulative market penetration of 28% (14,530 ÷ 52,500) through to the end of fiscal 2015/16.

Commercial Building Envelope - Windows Program

a) The total potential market is approximately 750 window replacement projects each year. Since program inception in fiscal 2006/07 through to the end of fiscal 2015/16, this represents 7,500 potential window replacement projects.

b) Through to the end of fiscal 2012/13, there have been 939 window replacement projects of the total potential 5,250 window replacement projects to date achieving 18% penetration (939 ÷ 5,250).

c) Over the next three years, 433 additional window replacement projects are forecast achieving 19% penetration (433 ÷ 2,250) for the period.

Commercial Building Envelope - Insulation Program

a) The total potential market is approximately 400 insulation replacement projects each year. Since program inception in fiscal 2006/07 through to the end of fiscal 2015/16, this represents 4,000 insulation replacement projects.

b) Through to the end of fiscal 2012/13, there have been 648 insulation replacement projects of the total potential 2,800 insulation replacement projects achieving 23% penetration (648 ÷ 2,800).

c) Over the next three years, 253 additional insulation replacement projects are forecast, achieving 21% penetration (253 ÷ 1,200) for the period.

Commercial Geothermal Program

a) The total potential market is approximately 243 electric heating replacement projects each year. Since program inception in fiscal 2007/08 through to the end of fiscal 2015/16, this represents 2,187 electric heating replacement projects.

b) Through to the end of fiscal 2012/13, there have been 121 geothermal installations of the potential 1,458 electric heating replacement projects, achieving 8% penetration.

c) Over the next three years, 51 additional geothermal installations are forecasted achieving 7% penetration (51 ÷ 729) for the period.

Commercial HVAC Program - Chillers

a) The total potential market is approximately 14 chillers replacement projects each year. Since program inception in fiscal 2006/07 through to the end of fiscal 2015/16, this represents 140 chiller replacement projects.

b) Through to the end of fiscal 2012/13, there have been 49 chiller replacement projects of the total potential 98 chiller replacement projects, achieving 50% penetration (49 ÷ 98).

c) Over the next three years, 25 additional chiller replacement projects are forecast achieving 60% penetration (25 ÷ 42) for the period.

Commercial HVAC Program – CO^2 Sensors

a) The total potential market is approximately 328 CO^2 sensors each year. Since program inception in fiscal 2009/10 through to the end of the fiscal 2015/16, this represents 2,296 CO^2 sensor installation opportunities.

b) Through to the end of fiscal 2012/13, there have been 173 CO^2 sensors installed through the program of the total potential 1,312 CO^2 sensors, achieving 13% penetration (173 ÷ 1,312).

c) Over the next three years, 360 additional CO^2 sensors are forecast to be installed through the program, achieving 37% penetration (360 ÷ 984) for the period.

Custom Measures Program

This program is used to support any and all energy saving upgrades not addressed by the existing suite of programs. It serves as a catch-all for sometimes unique upgrades. As such, the program does not define the overall market and market penetration.

Commercial Building Optimization Program

a) The total potential market is approximately 470 buildings meeting the requirements of the program.

b) Through to the end of fiscal 2012/13, there have been 12 buildings of the total potential 470 buildings, achieving 3% penetration (12 ÷ 470).

c) Over the next three years, 24 additional buildings are forecast, achieving an additional 5% penetration (24 ÷ 470), equating to total cumulative market penetration of 8% (36 ÷ 470) through to the end of fiscal 2015/16.

New Buildings Program

a) The total potential market is approximately 200 new commercial building projects each year. Since program inception in fiscal 2009/10 through to the end of fiscal 2015/16, this represents 1,400 new commercial building projects.

b) Through to the end of fiscal 2012/13, there have been 18 participating new commercial building projects of the total potential 800 new commercial building projects, achieving 2% penetration (18 ÷ 800).

c) Over the next three years, 74 additional participating new commercial building projects are forecast, thus achieving 12% penetration (74 ÷ 600) for the period.

Commercial Refrigeration Program

a) The total potential market is approximately 1,600 customers.

b) Through to the end of fiscal 2012/13, there have been 674 customers of the total potential 1,600 customers, achieving 42% penetration (674 ÷ 1,600).

c) Over the next three years, 133 additional customers are forecast, achieving an additional 8% penetration (133 ÷ 1,600), equating to total cumulative market penetration of 50% (807 ÷ 1600) through to the end of fiscal 2015/16.

Commercial Kitchen Appliances Program

a) The total potential market is approximately 40 electric steam cookers replaced each year. Since program inception in fiscal 2008/09 through to the end of fiscal 2015/16, this represents 320 electric steam cookers.

b) Through to the end of fiscal 2012/13, there have been 71 electric steam cookers replaced through the program of the total potential 200 electric steam cookers, achieving 36% penetration (71 ÷ 200).

c) Over the next three years, 63 additional electric steam cookers are forecast to be replaced through the program, thus achieving 53% penetration (63 ÷ 120) for the period.

Network Energy Management Program

a) The total potential market is approximately 300,000 personal computers.

b) Through to the end of fiscal 2012/13, there have been 1,225 personal computers of the total potential 300,000 personal computers, achieving 0.4% penetration (1,225 ÷ 300,000).

c) Over the next three years, 10,000 additional personal computers are forecast, thus an additional 3% penetration (10,000 ÷ 300,000), equating to total cumulative market penetration of 4% (11,225 ÷ 300,000) through to the end of fiscal 2015/16.

Residential Power Smart Programs

Home Insulation Program (HIP)

a) The total potential market is approximately 147,948 homes.

b) Through to the end of fiscal 2012/13, 31,313 homes of the potential 147,948 have participated in the HIP. The insulation retrofit market is unique in that it is reduced in size every year as houses are removed from the grid as a result of fire, demolition or abandonment and replaced with new homes that are not targeted under this market initiative. The total number of homes removed during the total program time period is estimated to be 12,429 reducing the overall market size to 135,519; thus 23% penetration (31,313 ÷ 135,519) has been achieved to 2012/13.

c) Over the next three years, 7,939 additional HIP participants are forecast and 2,850 dwellings are estimated to be removed from the grid; thus an additional 6% penetration (7,939 ÷ 134,198), equating to total cumulative market penetration of 29% (39,252 ÷ 134,198) through to the end of fiscal 2015/16.

Lower Income Energy Efficiency Program (LIEEP)

a) The total potential market of LICO 125 homes in Manitoba is represented by 74,057 owners and 8,044 renters. The primary targets within the LICO 125 market are homes with poor or fair insulation levels and standard efficient furnaces representing 19,065 homes and 18,319 furnaces respectively.

b) Through to the end of fiscal 2012/13, 6,616 homes have participated representing 8% overall penetration (6,616 ÷ 82,101). A total of 4,737 homes have been insulated; 2,700 of those homes represent customers with fair or poor levels of insulation totaling 14% market penetration (2,700 ÷ 19,065). 2,525 furnaces have been installed representing a total of 14% penetration (2,525 ÷ 18,319).

c) Over the next three years, 6,963 additional homes will participate, thus an additional 8% penetration (6,963 ÷ 82,101), equating to total cumulative market penetration of 17% (13,579 ÷ 82,101). For insulation measures, 3,106 additional customers with fair to poor insulation levels will be upgraded representing an additional market penetration of 16% (3,106 ÷ 19,065); totaling 30% penetration (5,806 ÷ 19,065) to end of 2015/16. For heating systems, 2,855 additional furnaces will also be upgraded representing additional market penetration of 16% (2,855 ÷ 18,319); thus a total market penetration for furnaces of 29% (5,380 ÷ 18,319) through to the end of fiscal 2015/16.

Water and Energy Saver Program (WESP)

a) The total potential market is comprised of 515,000 residential dwellings.

b) Through to the end of fiscal 2012/13, there have been 109,978 WESP participants of the total potential 515,000 residential dwellings, achieving 21% penetration (109,978 ÷ 515,000).

c) Over the next three years, 57,600 additional residential dwellings are forecast to participate, achieving an additional 11% penetration (57,600 ÷ 515,000), which equates to total cumulative market penetration of 33% (167,578 ÷ 515,000) through to the end of fiscal 2015/16.

Refrigerator Retirement Program

a) The total potential market is approximately 194,000 refrigerators and 150,000 freezers.

b) Through to the end of fiscal 2012/13, 15,147 refrigerators and 1,870 freezers have been removed from customer homes representing 8% penetration (15,147 ÷ 194,000) for refrigerators and 1% penetration (1,870 ÷ 150,000) for freezers.

c) Over the next three years, 30,000 additional refrigerators and 10,000 additional freezers are forecast to be removed from customer homes. This represents an additional 15% penetration (30,000 ÷ 194,000) for refrigerators and 7% penetration (10,000 ÷ 150,000) for freezers, equating to total cumulative market penetration of 23% (45,147 ÷ 194,000) for refrigerators and 8% (11,870 ÷ 150,000) for freezers through to the end of fiscal 2015/16.

Residential Earth Power Loan

a) The total potential market is approximately 15,300 homes replacing their heating system annually and an estimated 4,550 newly constructed homes each year totally 19,850.

b) Since the beginning of the program in 2002/03 through to the end of fiscal 2012/13, there have been 1,223 participating customers of the total potential 107,500 customers, achieving 1.1% penetration (1,223 ÷ 107,500)

c) Over the next three years, 263 additional participating customers are forecasted, thus achieving 0.4% (263 ÷ (19,850*3)) penetration for the period.

REFERENCE: Executive Summary; Appendix 4.3 Demand Side Management Potential Study

PREAMBLE: MB's Executive Summary (p 10) indicates that the domestic load (before DSM) is expected to grow at an average annual rate of 1.6% for the next 20 years. Over the same time period, the DSM Potential Study forecasts an annual growth rate of only 0.9%.

QUESTION:

Please explain how there can be such a difference in the forecasted growth between Manitoba Hydro's load forecast and the DSM Potential Study Baseline forecast. Notably, please explain why Manitoba Hydro expects growth in all sectors including the commercial sector, while the potential study forecasts a baseline decrease in consumption for this sector.

RESPONSE:

Please refer to Manitoba Hydro's response to PUB/MH I-248.

REFERENCE: Executive Summary; Appendix 4.3 Demand Side Management Potential Study

QUESTION:

Which of these conflicting annual growth rates does Manitoba Hydro consider as valid?

RESPONSE:

Manitoba Hydro's load forecast represents the best estimate of Manitoba's future energy requirements. Please refer to Manitoba Hydro's response to PUB/MH I-248.

REFERENCE: Executive Summary;. Appendix 4.3 Demand Side Management Potential Study

QUESTION:

Please submit, if required given your answers to the two previous questions, an updated Demand Side Management Potential Study based on updated growth rates for the Electric Baseline Forecast.

RESPONSE:

Please refer to Manitoba Hydro’s response to PUB/MH I-248.

REFERENCE: Executive Summary; Page No.: 31

PREAMBLE: "The sensitivity and stress test demonstrated that increasing the DSM within a reasonable range (1.5 times) and for an ideal range (4.0 times)…" (Executive Summary, p.31)

QUESTION:

What is the exact meaning of "ideal range"?

RESPONSE:

The “ideal” range noted at line 28 of page 31 of the Executive Summary was intended to represent a proxy for the “Market Potential” as defined on page 1-1 of the Appendix 4.3 – DSM Potential Study (i.e. “under ideal market, implementation, regulatory and customer preference conditions”).

REFERENCE: Executive Summary; Page No.: 31

PREAMBLE: "The sensitivity and stress test demonstrated that increasing the DSM within a reasonable range (1.5 times) and for an ideal range (4.0 times)…" (Executive Summary, p.31)

QUESTION:

Under which criteria did Manitoba Hydro establish that 4 times the 2013 DSM forecast was an "ideal range" for sensitivity analysis?

RESPONSE:

Please refer to Manitoba Hydro's response to CAC_GAC/MH I-029a.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study;

PREAMBLE: AMI Smart Grids

QUESTION:

Manitoba Hydro ran a pilot project regarding Advanced Metering Infrastructure and smart meters from 2006 to 2009. What were the main objectives for running this pilot program? Please provide an explanation of how the results of the pilot were used. Have any studies been done on the results of the pilot? If so, please provide us a copy of the study. If not, then please explain why not.

RESPONSE:

Manitoba Hydro undertook an Advanced Metering Infrastructure (AMI) pilot program for the purpose of testing two smart metering technologies available at the time and to assess the various benefits and/or potential issues associated with the technology. Implementation began in January 2007 with approximately 4,500 electric smart meters and 950 natural gas smart modules co-located in Winnipeg, and with approximately 200 electric smart meters in a rural area near Landmark. In Winnipeg, the pilot used pre-production wireless communication. In rural Manitoba, the pilot used established powerline carrier communication.

The pilot program ended in the summer of 2009 with successful laboratory testing of the communication capabilities of production ready electric smart meters and natural gas smart modules. This testing also examined the data collection engine and commercially available home area network devices, such as thermostats, displays, and load controllers. Delays were experienced in obtaining Measurement Canada approvals and by 2009 the wireless equipment was no longer commercially available.

The pilot program demonstrated successful communication between electric meters and a central location, operation in Manitoba weather, and collection engine communication of temperature or cycling commands to thermostats, information messages to displays, and on/off commands to load controllers. The pilot also provided valuable operational data, enabling Manitoba Hydro to experience many of the enhanced functions offered by an AMI system to:

- Receive accurate electricity readings and events,
- Store and review regular electricity data population in the meter data management system,
- Update meter firmware remotely,
- Disconnect/reconnect and load limit electricity meters remotely,
- Identify electricity supply issues through blink counts,
- Identify occurrences of concern through volt and tamper detection, and
- Better define process and operational impacts of automated meter communication.

Attached is a status report dated February 2, 2010.

In 2012, Manitoba Hydro proceeded to integrate the readings received from the electric smart meters into its billing system, reducing estimated bills for the majority of the electric smart meters still in use and improving the read to bill lag by two to four days on most meters billed to an AMI reading.

Manitoba Hydro continues to assess the business case and timing for AMI based on the operational findings of the pilot and by monitoring AMI implementations at other utilities.

PUB/CENTRA I-73

Subject: **Tab 9: Rate Base**

Reference: **Tab 9 Page 17 of 63**

b) Please provide Centra's most recent status report and business plan on AMI.

ANSWER:

Attached is the most recent status report on AMI as filed on February 2, 2010 in response to Directive 13 from Board Order 128/09, with respect to Centra's 2009/10 & 2010/11 General Rate Application.

Manitoba Hydro

PO Box 815 • Winnipeg Manitoba Canada • R3C 0G8
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February 2, 2010

PUBLIC UTILITIES BOARD OF MANITOBA
400-330 Portage Avenue
Winnipeg, Manitoba
R3C 0C4

ATTENTION: Mr. H. M. Singh, Acting Secretary and Executive Director

Dear Mr. Singh:

RE: CENTRA GAS MANITOBA INC. ("CENTRA")
ADVANCED METERING INFRASTRUCTURE

On September 16, 2009 the Public Utilities Board issued Order 128/09 with respect to Centra's 2009/10 & 2010/11 General Rate Application in which it directed Centra to file a business plan with respect to Advanced Metering Infrastructure ("AMI"). In Centra's 2010/11 Cost of Gas Application, filed December 23, 2009, Centra provided information in response to this directive in Tab 9 of the Application and advised of its intentions to file a status report on AMI.

The status report, included as an attachment to this letter, provides Centra's findings and results of the AMI pilot project, an assessment of the anticipated feasibility of current AMI product costs and benefits, and future technical factors and considerations which may impact the feasibility of the business plan in the future.

Centra is mindful of the PUB's direction and requirement to submit a business case prior to deployment of further AMI investment. Preliminary evidence and a thorough examination of the AMI industry suggests circumstances may develop in the future which will enhance the feasibility of this technology. Centra is therefore providing the enclosed status report and will keep the PUB apprised if future developments warrant revisiting of further AMI investment.

Should you have any questions regarding this submission, or prefer a paper copy, please contact the writer at 360-3468 or Greg Barnlund at 360-5243.

Yours truly,
MANITOBA HYDRO LAW DEPARTMENT
Per:

M Murphy

Marla D. Murphy
Barrister and Solicitor
Att.

Cc: Mr. B. Peters, Fillmore Riley
Mr. R. Cathcart, Cathcart Advisors Inc.
Mr. B. Ryall, Energy Consultants Inc.

EXECUTIVE SUMMARY

The current state of technology pricing, functionality and associated benefits of an Advanced Metering Infrastructure (AMI) solution for natural gas metering in Manitoba does not support an overall deployment strategy at this time. Manitoba Hydro will continue to monitor the AMI industry and through discussions with industry associations and vendors encourage improved functionality and lower pricing. When Manitoba Hydro can reasonably demonstrate an overall favorable strategy for the deployment of an AMI technology solution, Centra will provide a business case to the Public Utilities Board, prior to proceeding beyond the pilot project expenditures, as directed in Order 128/09.

What is AMI?
Advanced Metering Infrastructure (AMI) refers to systems that measure, collect and analyze energy usage from advanced devices such as electricity meters, gas meters, and/or water meters, through various communication media on request or on a pre-defined schedule. The network between the measurement devices and business systems allows information to be communicated from the meter to the utility and from the utility to the meter.

Preliminary Results - Benefit Assessment
Preliminary examination of the projected benefits and costs of an AMI solution for the natural gas system do not support deployment at this time. Under current product costing and functionality, Centra is projecting a net cost for natural gas AMI in Manitoba.

Preliminary examination of the projected benefits and costs of an AMI solution for Manitoba Hydro's electric system appear positive. Under current product costing and functionality, Manitoba Hydro is projecting a net benefit for electric AMI in Manitoba.

When natural gas and electricity net benefits are combined, preliminary examination projects a small net benefit.

The cost to install AMI equipment, software, hardware, and communication is considerably higher than the cost to install the more established Automated Meter Reading (AMR) technology for both natural gas and electric systems. However, the AMI functionality for electric systems is considerably more enhanced than that provided by the AMR systems while current AMI functionality for natural gas systems is only slightly more beneficial than offered by AMR.

Manitoba Hydro will continue to monitor the market and through discussions with industry associations and vendors encourage improved functionality and lower pricing.

Summary of Pilot Findings

The purpose of the AMI pilot project was to assess the latest technology solutions for operability and functionality in Manitoba's climate and service territory and to explore the impact of an automated meter communication system on Manitoba Hydro's overall operations and information systems.

In January 2007, Manitoba Hydro began implementation of its AMI pilot project. Under the pilot, 4,500 pre-production Itron OpenWay electricity meters and 950 co-located Canadian Meter natural gas meters retrofitted with the Itron OpenWay Index were installed within Winnipeg and 198 Itron Centron electricity meters equipped with Cannon PowerLine Carrier technology were installed near Landmark, Manitoba. In Winnipeg, the pilot used Itron's latest wireless communication technology, the OpenWay meter. In rural Manitoba, the pilot used Cannon's established powerline carrier communication technology. The powerline system offers many similar features as the wireless system, but is more suited to regions with sparse population density.

Itron's Enterprise Edition Meter Data Management (MDM) and OpenWay Collection Engine systems were installed to store and manage the data. The MDM stores data from both Itron and Cannon meters and provides the OpenWay remote disconnect/reconnect function. The OpenWay Collection Engine controls reading and other communications with the meters.

The urban and rural AMI systems were tested to validate features available with the advanced meters. Both systems passed all required electric system tests. However, operational testing of the electric Itron OpenWay meters found that less than 10% of natural gas meters communicated with the electricity meters provided for the pilot project. Communication was possible only in situations where the natural gas meter was directly in the electricity meter's line of sight. Due to the fact that the units were pre-production models, there were different vintages of the ZigBee RF communication protocol in Itron's electricity and natural gas meters. Itron has made additional changes to the ZigBee RF communication with the newly released R7 electric OpenWay meter and these units were tested in Manitoba Hydro's Meter Shop during the summer of 2009. Testing confirmed the improved communication capabilities over significant distances and obstacles.

The pilot was effective in that Manitoba Hydro accomplished its objective of successfully installing an urban RF AMI system and a rural PLC system and exploring the available functionalities. Through the pilot, Manitoba Hydro has confirmed that moving to a broader deployment of an AMI solution for Manitoba Hydro's electricity and natural gas systems may offer significant benefits. The pilot project demonstrates that the technologies supporting an electric and natural gas solution are still evolving and that Manitoba Hydro has the opportunity to benefit from experiences in other jurisdictions.

As more of the larger utilities purchase, use and enhance the AMI solutions, Manitoba Hydro anticipates that:

- the unit cost of production AMI meters will decrease,
- options and functionality will increase, and
- many of the anticipated benefits will be validated.

Industry

To date, the main focus of market development for AMI has been for electric systems, with offerings for water and natural gas systems being limited primarily to meter reading.

Provincial and state government energy policies are driving AMI adoption in other jurisdictions. In those jurisdictions AMI is viewed as a means of addressing significant forecasted electricity capacity and supply constraints. Utilities appear to be investing in AMI in those jurisdictions (particularly in the United States) where utilities are capacity constrained and where government funding has been made available to support Smart Grid infrastructure investment.

Generally speaking, most natural gas utilities are not pursuing AMI at this time. Those choosing to invest in metering systems are either deploying AMR for the first time or enhancing their existing AMR system. Publicly available information suggests that some natural gas utilities, such as Terasen Gas in British Columbia and Alabama Gas Corporation in Alabama, are pursuing Mobile AMR technologies. Where legislative support exists allowing for investment recoveries, some utilities, such as the Southern California Gas Company, are investing in AMI for their natural gas system.

Future in Manitoba

AMI for electricity and natural gas services offers considerable potential for enhanced customer service offerings. Due to the significant investment and commitment required under an AMI deployment, Manitoba Hydro will require further confirmation of the anticipated future benefits and a more detailed analysis of the project risks before a strategy and supporting business case can be completed.

When a substantive business case supporting AMI can be achieved, Corporate approval of the strategy, budget and schedule will be sought. Following that approval, Centra will submit its business case to the PUB. The cost consequences of any subsequent deployment of AMI for the natural gas business will be addressed in subsequent General Rate Applications brought forth by Centra.

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1.0 Status Statement

The current state of technology pricing, functionality and associated benefits of an Advanced Metering Infrastructure (AMI) solution for natural gas metering in Manitoba does not support an overall deployment strategy at this time. Manitoba Hydro will continue to monitor the market and through discussions with industry associations and vendors encourage improved functionality and lower pricing. When Manitoba Hydro can reasonably demonstrate an overall favorable strategy for the deployment of an AMI technology solution, Centra will provide a business case to the Public Utilities Board prior to proceeding beyond the pilot project expenditures as directed in Order 128/09.

2.0 Background

2.1 Current Meter Reading Practice

Manitoba Hydro outsources the majority of its meter reading requirements to Manitoba Hydro Utility Services (MHUS), a wholly owned subsidiary of Manitoba Hydro. Generally, a customer's meter is manually read by MHUS staff every second month. Meter readers typically use portable hand-held devices to enter meter read data. Bills are presented to customers on a monthly basis and thus a bill based upon estimated consumption is prepared for the months in which meters are not read.

In addition, Manitoba Hydro has over 74,000 "self read" customers who are asked to provide regular meter readings. These customers are primarily located in low density, rural areas of the Province.

2.2 What is Advanced Metering Infrastructure (AMI)?

Advanced Metering Infrastructure (AMI) refers to systems that measure, collect and analyze energy usage from devices such as advanced electricity, natural gas and/or water meters through various communication media on request or on a pre-defined schedule. This infrastructure includes hardware, software, communications systems, associated customer information and billing systems and meter data management (MDM) software.

AMI is notably characterized as a system that facilitates two-way communication between customers and the utility. The network between the measurement devices and business systems allows information to be communicated both from the customer to the utility and from the utility to the customer. This enables customers to either participate in, or provide, demand response solutions, products and services. By providing information to customers, the system can assist a change in energy usage from their normal consumption patterns, either in response to changes in price or as incentives designed to encourage lower energy usage use at times of peak-demand periods or higher wholesale prices or during periods of low operational systems reliability.

2.3 Technology Options

Automated Meter Reading (AMR) represents meter reading technologies with one-way communication of the meter data. Advanced Metering Infrastructure (AMI) represents technologies that provide two-way communication from the utility to the meter and the meter to the utility.

2.3.1 Mobile AMR

Under this configuration, an electronic receiver/transmitter (ERT) meter communicates a reading to a mobile unit, either a person walking by with the handheld unit or a vehicle driving by with a personal computer. As the mobile unit passes the meter, it sends a signal to "wake-up" the meter, and then the meter sends the reading.

2.3.2 Fixed Network AMR

Under this configuration, the meter communicates a meter reading over a communication network (e.g. radio frequency, telephone, cellular, powerline carrier, etc) when it receives a signal to "wake-up". This system supports one way communication from the meter to the utility.

2.3.3 Fixed Network AMI

Under this configuration, data communication is two-way. Both the utility and the meter communicate over a communication network (e.g. radio frequency, telephone, cellular, powerline carrier, etc) with data able to move from the meter to the utility and from the utility to the meter.

3.0 Manitoba Hydro AMI Pilot Project

Developments in the communication technology and functionality of AMR and AMI have increased the potential benefits. Manitoba Hydro has and continues to explore the feasibility and business justification for automating meter communication.

3.1 Pilot Project Objectives

The purpose of the AMI pilot project was to assess the latest technology solutions for operability and functionality in Manitoba's climate and service territory, and to explore the impact of an automated meter communication system on Manitoba Hydro's overall operations and information systems.

3.2 Pilot Project Background

In 2004, Fixed Network AMR technologies appeared to be highly promising and Manitoba Hydro proposed to explore this opportunity under a pilot project, looking at the best technology solutions available for Manitoba Hydro's operating conditions and business environment.

In May 2006, prior to pilot initiation, Itron introduced the OpenWay Advanced Metering Infrastructure (AMI) concept to replace their Fixed Network AMR product. Although not commercially available, the OpenWay AMI meters offered more potential benefits. The additional benefits of the AMI system included a two-way communication network that could be utilized not only for electric and natural gas meter communication but also for home area network and potentially water meter reading and distribution automation. Other features fully incorporated within the physical meter included the ability to remotely load limit, disconnect, and reconnect meters.

In January 2007, an agreement for the pilot project was signed by Manitoba Hydro and Itron Canada Ltd to explore a hybrid solution for Manitoba. Under the pilot agreement, up to 5,000 pre-production wireless Itron OpenWay electricity meters and 1,000 co-located Canadian Meter natural gas meters retrofitted with the Itron OpenWay Index were to be installed within Winnipeg and up to 200 Itron Centron electricity meters equipped with established Cannon PowerLine Carrier technology were to be installed near Landmark, Manitoba. The powerline carrier (PLC) system offers many similar features as the wireless system, but is more suited to regions with sparse population density. Itron and Cannon were co-operative business partners.

The pilot ended in the summer of 2009 with the laboratory testing of the improved communication capabilities of the new production ready Itron OpenWay R7 electric and natural gas meters.

3.2 Pilot Project Technical Infrastructure

Under the pilot, approximately 4500 Itron OpenWay Radio Frequency (RF) electricity meters and cellular telephone relay meters were installed in higher density areas of central Winnipeg (i.e. North River Heights, West End, North End, West Kildonan and Maples). In addition, approximately 950 Canadian Meter natural gas meters equipped with the Itron OpenWay RF Indexes were installed at locations with the OpenWay electricity meters. The electricity meters communicated with the natural gas meters through a 2.4GHz Zigbee[1] RF.

[1] ZigBee is a specification for a communication protocol using small, low-power digital radios based upon an IEEE standard.

In addition, 198 Itron Centron electricity meters equipped with Cannon PowerLine communication technology were installed in the area outside of Landmark, Manitoba to test their suitability in low density rural areas.

Itron's Enterprise Edition Meter Data Management (MDM) and OpenWay Collection Engine systems were installed in order to store and manage the data. The MDM stores data from both Itron and Cannon meters and provides the OpenWay remote disconnect/reconnect function. The OpenWay Collection Engine controls reading and other communications with the meters.

3.4 Pilot Project Findings

Manitoba Hydro accomplished its objectives of successfully installing an urban RF AMI system and a rural PLC system and exploring the available functionalities of automated meter communication.

3.4.1 Technical Performance

Technical testing of the electric and natural gas AMI systems were undertaken through the pilot project.

Electric AMI Meters - The urban and rural AMI systems were tested to validate features available with the advanced meters. The urban OpenWay System from Itron passed all tests. The Power Line Carrier system from Cannon did not include the remote load limiting, disconnection and Time of Use (TOU) metering function that was available with the Itron OpenWay Models.

Testing for both the urban and rural systems included an evaluation of the read reliability rate, read accuracy, on demand read, read retrieval, end point voltage, net metering, time synching, outage status, and tamper flags. The urban system testing also included disconnect/reconnect, load limiting, and TOU rates functionality.

Natural Gas AMI Meters - Operational testing of the electric Itron OpenWay meters found that less than 10% of natural gas meters communicated with the AMI pilot electricity meters. Communication was possible only in situations where the natural gas meter was directly in the electricity meter's line of sight. Due to the fact that the units were pre-production models, there were different vintages of ZigBee RF communication protocols in Itron's electricity and natural gas meters. Itron has made additional changes to the ZigBee RF communication with the newly released R7 electric OpenWay meter and these units was tested in Manitoba Hydro's Meter Shop during the summer of 2009. Testing confirmed the improved communication capabilities over significant distances and obstacles.

Home Area Network Devices - Operational testing of the OpenWay collection engine was also undertaken during the summer of 2009 within a lab setting for commercially available Home Area Network Devices, such as thermostats, displays and load controllers. Laboratory results showed that the collection engine could communicate temperature or cycling commands to thermostats, information messages to the displays, and on/off commands to the load controllers.

3.4.2 Implementation Findings

Manitoba Hydro gained valuable knowledge and experience with regards to the process of implementing the technology infrastructure to support an AMI system in Manitoba. This experience included coordinating a large number of meter exchanges for both electric and gas, setting up the MDM and collection engine for managing data, operating the MDM and collection engine, and communicating consistent messages with staff and customers to support the deployment.

Through the pilot, Manitoba Hydro was able to experience many of the enhanced functions offered by an AMI system. Manitoba Hydro was able to:

- Receive accurate electric readings and events,
- Store and review regular electric data population in the MDM system,
- Update meter firmware remotely
- Disconnect/reconnect and load limit electricity meters remotely,
- Identify electric supply issues through blink counts,
- Identify occurrences of concern through volt and tamper detection, and
- Better define process and operational impacts of automated meter communication.

3.4.3 Lessons Learned

Through the pilot project a number of learnings were highlighted which should be taken into consideration prior to a broader deployment of this type of technology solution:

- Technologies and software will continue to evolve over the implementation period of a broader deployment, therefore, the utility must recognize this and factor into the AMI solution chosen;
- Infrastructure cost of AMI is greater than that of AMR;
- Deployment timelines may be affected by delays in Measurement Canada approvals on "next generation" or evolving technology meters;
- It may be more cost effective and may result in less customer disruption in the course of implementation if the Corporation obtains Measurement Canada certification for field exchange and resealing of natural gas indices;
- Purchasing commercialized production meters provides operational benefits and reduces project risks;
- Technology costs or the available functionality of natural gas AMI offerings may change such that the systems may become more cost effective;

- An internal and external communication plan is important for successful implementation;
- A designated workforce is required to support effective mass deployment; and
- A well defined and flexible data communication configuration is required to ensure effective and consistent communication now and in the future (e.g. data priority on cellular communication networks, optimal location for cell relays).

While moving to full deployment of an AMI solution for Manitoba Hydro's electricity and natural gas systems may offer significant benefits, the experience of the pilot project demonstrates that the technologies supporting an electric and natural gas solution are still evolving and that Manitoba Hydro has the opportunity to benefit from experiences in other jurisdictions.

As more of the larger utilities purchase, use and enhance the AMI solutions, Manitoba Hydro anticipates that:

- the unit cost of production AMI meters will decrease,
- options and functionality will increase, and
- many of the anticipated benefits will be validated.

4.0 The AMI Industry

To date, the main focus of the marketplace for AMI has been for electric systems, with offerings for water and natural gas systems being limited to meter reading.

4.1 Government Perspectives

Provincial and state government energy policies are driving AMI adoption in other jurisdictions, with the focus on managing electricity capacity concerns. Ontario and British Columbia have established provincial policies on the implementation of AMI as a means of alleviating significant forecasted electricity capacity constraints. Both Ontario and British Columbia have mandated the implementation of smart meters. Ontario was the first province to mandate implementation with the focus of the technology being to allow for measurement in hourly intervals, data storage, and transmission of meter readings to a central billing system on a daily basis for customer access and billing purposes. British Columbia was the second province to mandate implementation. BC Hydro received proposals for an AMI solution in July 2008; however, as of January 2010 a contract has still not yet been awarded. Alberta has not mandated implementation of smart metering at this time; however, they have established a provincial energy strategy supporting adoption.

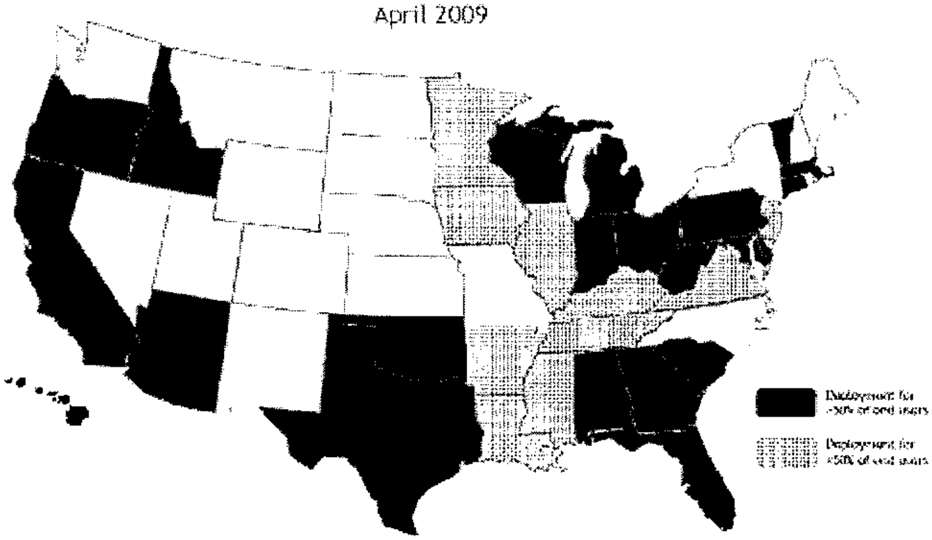
Manitoba and Quebec do not face the same immediate electricity capacity constraints. As such, the business case supporting AMI in Manitoba is based upon reductions in operating costs and improved revenue collection, not demand reduction or avoided generation costs. Hydro Quebec has initiated a pilot project, targeted to end in March 2010, to assess the benefits of TOU metering and rates and critical peak pricing within their market. At this time, Hydro Quebec has not determined whether the additional functionalities of AMI will provide benefits which offset the costs of AMI infrastructure.

4.2 *Utility Perspectives*

The direction of electric, natural gas and combined electric/gas utilities differs as a result of differences in the local market situation and business environment from jurisdiction to jurisdiction.

- *Electric Utilities*: In the United States, several electric utilities are implementing AMI systems, particularly in situations where there are electricity capacity constraints and where government funding is available to support Smart Grid infrastructure installations. This is evident in several jurisdictions across the United States (refer to Figure 1.1). Examples include Southern California Edison and Sacramento Municipal Utility District in California and Georgia Power in Georgia. In Canada, the largest area of deployment is in Ontario where energy policies support infrastructure investment and includes adoption by utilities such as Toronto Hydro, Power Stream, Horizon and Hydro One.

Utility-Scale Deployment of Smart Meters
April 2009



Source: EEI

- *Natural Gas Utilities*: Most natural gas utilities are not pursuing AMI at this time. Publicly available information suggests that some natural gas utilities, such as Terasen Gas in British Columbia and Alabama Gas Corporation in Alabama, are still pursuing Mobile AMR technologies. Where legislative support exists allowing for investment recoveries, some utilities, such as the Southern California Gas Company, are investing in AMI for their natural gas system.

- *Combined Electric/Gas Utilities*: Where utilities are capacity constrained and where government policy or funding supports exist, utilities are exploring AMI systems. Some utilities which had already converted to mobile AMR, such as Xcel Energy in Minnesota, are investing in AMI for their electric system and planning to enhance their existing AMR system for natural gas.

4.3 Vendors/Suppliers

The main focus of meter manufacturers for AMI systems has been on electricity. This focus arises from demand in larger markets, such as California, the northeastern states and Ontario, where electric utilities are facing significant capacity constraints and where state and provincial governments have mandated Smart Metering requirements. Most regions facing these circumstances are pursuing TOU Rates and Critical Peak Pricing to provide customers with the appropriate price signals as to the cost of providing power. AMI provides these utilities with the ability to measure energy usage by time periods and bill the customer accordingly with the goal of shifting energy use to off-peak periods.

Prior to Manitoba Hydro undertaking a broader implementation of AMI the Corporation will pursue a competitive bid process to obtain the most beneficial combination of pricing and enhanced functionality. A number of consultants, meter/equipment manufacturers, communication providers and software vendors operate within in the North American marketplace. These vendors/suppliers continue to enhance and expand their service offerings to meet the evolving needs of customers and utilities.

4.4 Product Functionality & Associated Benefits

As mentioned, the primary focus of vendor/supplier product enhancements and research/development to date has been in the area of electricity supply. This is evident in the list of available features.

Electricity Meters - The functionality and benefits available to Manitoba Hydro through the current electric AMI solutions are as follows:

- Regular Meter Readings
  - Reduced data collection costs

    - More frequent meter reading with fewer data entry errors
    - Interval readings
- Customer Billing
    - Reduced lag in the "read-to-bill" cycle
    - Reduced costs associated with reductions in re-billing for meter reading corrections
- Account Management (Remote disconnect/load limit/reconnect)
- Tamper & Theft Detection
- Customer Inquiry & Administrative Support
- Distribution System
    - Locating intermittent faults
    - Voltage recording
    - Peak load data
    - Feeder outage detection
    - Ice melt switching

In addition, AMI is the leveraging technology that is expected to support the overall development of Smart Grid. The two-way communication and data exchange supports future product offerings, such as Home Area Networks, and will help utilities manage emerging system demands, such as plug-in hybrid vehicles, and distributed generation. For additional information on emerging matters, please refer to Section 6.0.

Natural Gas Meters - The functionality and benefits available to Manitoba Hydro through the current natural gas AMI solutions are as follows:

- Regular Meter Readings
    - Reduced data collection costs
    - More frequent meter reading with fewer data entry errors
- Customer Billing
    - Reduced lag in the "read-to-bill" cycle
    - Reduced costs associated with reductions in re-billing for meter reading corrections
- Account Management
- Tamper & Theft Detection
- Customer Inquiry & Administrative Support

As mentioned, to date, the AMI industry has invested less effort in enhancing functionality for natural gas AMI solutions when compared to electric AMI applications.

5.0 Costs & Benefits Assessment

Manitoba Hydro's approach to assess the feasibility of AMI in Manitoba is to ensure that the recommended direction will benefit ratepayers. As such, the benefits being examined are categorized as:

1. Financial - cost reductions and improved revenue streams.

2. Productivity/Operational - productivity improvements.
3. Qualitative - non-quantifiable benefits.

5.1 Preliminary Financial Assessment

In PUB Order 128/09, Centra was directed to file a business plan with respect to the AMI project by January 15, 2010, and prior to proceeding beyond the pilot project expenditures. The PUB indicated that the business plan should include an assessment of the economic and non-economic benefits of AMI, including safety-related matters, for both the meter reader and for Centra's customers. Although Manitoba Hydro and Centra have determined not to proceed with a formal business plan with respect to AMI expenditures at this point, the following information has been provided to the PUB to address the matters raised in Order 128/09.

Preliminary examination of the benefits and costs of an AMI solution for the natural gas system do not support deployment at this time. Under current product costing and functionality, Centra is projecting a net cost. The cost to install AMI equipment, software, hardware, and communication is considerably higher than the cost to install the more established AMR technology, with current AMI functionality being only slightly more beneficial than AMR.

Preliminary examination of the benefits and costs of an AMI solution for Manitoba Hydro's electric system appear positive. Under current product costing and functionality, Manitoba Hydro is projecting a net benefit. The cost to install AMI equipment, software, hardware, and communication is considerably higher than the cost to install the more established AMR technology; however, the AMI functionality for electric systems is considerably more enhanced than that provided by the AMR systems.

When natural gas and electricity net benefits are combined, preliminary examination projects a small net benefit.

Manitoba Hydro continues to detail project impacts and risks prior to providing a strategy and supporting business case for corporate review.

The current state of technology cost, functionality and associated benefits from an AMI solution for the natural gas system in Manitoba do not support an overall deployment strategy at this time. Manitoba Hydro will continue to monitor the developments in the AMI industry and through discussions with industry associations and vendors encourage improved functionality and lower pricing.

5.2 Productivity/Operational Benefits

Productivity benefits include reductions in the time that staff spend on meter reading, collection and inquiry support in situations where the reduction in those activities could present opportunities for other valued-added work to be completed. Preliminary analyses suggest material productivity gains may be possible after full AMI deployment.

5.3 Qualitative Benefits

Qualitative benefits of implementing an AMI system in Manitoba would include improvements to customer and employee safety and reduction in environmental impacts.

Safety - Reduction in injuries and lost time for staff driving or walking on site to access meters to obtain meter readings.

Environment - Manual meter reading operations require meter readers to travel from location to location to perform readings. In the 2008/09 fiscal year, MHUS staff travelled approximately 734,000 km to perform meter reading activities. The adoption of AMI may significantly reduce this travel requirement, therefore resulting in an estimated annual reduction of approximately 250 tonnes of CO_2 equivalent emissions.

6.0 Future Considerations

There are potential industry developments that may have an impact on the future feasibility of the implementation and operation of AMI systems for both natural gas and electric meters in Manitoba. Some of these developments are noted in the sections below.

6.1 Measurement Canada

- Manitoba Hydro may consider exploring the requirements necessary to obtain Measurement Canada accreditation to perform in-field retrofits and resealing of natural gas meters as the preferred approach under a broader deployment of a natural gas AMI solution.

- Measurement Canada has proposed changes to the requirements of their Compliance Sampling Program in order to improve the statistical validity of the sampling program. It is expected that these changes, if implemented, will substantially increase the number of electric and natural gas meters exchanged annually. Consequently the business case supporting AMI may become more favorable as the analysis may include only the incremental cost of installing the AMI meter versus non-AMI meters for a larger number of customers

6.2 *Product Enhancements*

The industry is recognizing that additional functionalities are required to further justify utility investment in natural gas AMI systems. Based upon discussions with industry participants, the following list of potential and preferred natural gas functionalities are being or are expected to be considered by AMI system vendors/suppliers:

- Pressure sensor devices on metering and regulation apparatus
- Corrosion detection devices
- Carbon Monoxide or natural gas emission detectors
- "Strained riser" detection devices
- Remote disconnect of the natural gas service
- Daily metering information to facilitate settlement with natural gas commodity supply contracts
- Distribution system load analysis and modeling
- Software to set min/max for typical use on a service and report unusual use to the customer and/or utility
- Software to use the more granular resolution on AMI meters to facilitate leak detection

Although industry participants have identified interest in these desired options, no AMI vendor has committed to delivery of any of these options within any specific time frame or cost. Recently, Itron announced that it is currently developing systems to allow their long-established Fixed Network AMR solution to gather pressure data and to monitor cathodic protection. It is anticipated, that once proven, this functionality will be configured to work within Itron's OpenWay natural gas AMI solution.

6.3 *Time of Use Rates*

As mentioned, the focus of AMI deployment is in jurisdictions facing electricity capacity constraints. Utilities are looking to TOU Rates and Critical Peak Pricing as one more tool to assist in managing these significant concerns.

The PUB has directed Manitoba Hydro to investigate the implementation of TOU electricity rates for large industrial customer classes, which already utilize sophisticated metering technology. Manitoba Hydro is currently investigating TOU rate alternatives for the 43 General Service Large customers with service of at least 30 kV. These customers are already equipped with MV90 interval metering.

TOU Rates and Critical Peak Pricing strategies are not required nor are they generally applicable to the natural gas industry and are therefore not a significant driver behind natural gas AMI implementation.

6.4 Smart Grid and the Application of AMI Technologies

The Smart Grid is a bi-directional electricity and communication network that provides the ability of the distribution and transmission systems to self diagnose and to adjust energy flows. It includes software and hardware applications for a dynamic, integrated, and interoperable optimization of electric system operations, maintenance, and planning; distributed generation interconnection and integration; and feedback and controls at the consumer level.

The ability of the system to self-diagnose and adjust energy flows will result in higher reliability and a reduction in restoration times. Service interruptions can create customer dissatisfaction and more specifically for commercial/industrial customers may have significant financial impacts such as lost productivity.

AMI is one of the enabling technologies supporting Smart Grid. AMI creates the critical link for the distribution system to interact with Home Area Networks (HAN) allowing the customer to access new technologies and energy service options. AMI provides customers with the ability to install HAN which interconnect appliances throughout the home and are capable of interacting on a real-time basis with the electric system infrastructure. This technology would allow customers to view, analyze and adjust their energy use patterns. AMI and HAN technologies provide the opportunity to present new choices for customers, such as TOU rates and the ability to modify energy consumption to limit peaks or shift loads and, in the future, integrate sources of renewable energy such as small wind and solar generation or supply energy to the grid from electric storage devices such as plug-in hybrid electric vehicles.

7.0 Conclusion & Next Steps

AMI for electricity and natural gas services offers considerable potential for enhanced customer service offerings. Due to the significant investment and commitment required under an AMI deployment, however, Manitoba Hydro requires further confirmation of the future benefits and a more detailed analysis of the project risks before a strategy and supporting business case can be completed.

Manitoba Hydro will continue to monitor the AMI industry, the progress of Measurement Canada changes and the emergence of additional natural gas functionalities. When a substantive business case supporting AMI can be achieved, corporate approval of the strategy, budget and schedule will be sought. Following corporate approval of the business case, project strategy and budget, Centra will submit a business case to the PUB. The cost consequences of any deployment of AMI for the natural gas business will be addressed in subsequent General Rate Applications brought forth by Centra.

Once approved, implementation of the AMI strategy will occur with the issuance of RFPs for equipment, installation, software, and consulting; the selection of consultants and vendors; and ultimately the implementation of the AMI technology solution.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study

QUESTION:

Has Manitoba Hydro completed any studies regarding the impact of introducing more Demand Response programs including, but not limited to, Time of Use Rates, Real Time Pricing, Critical Peak Pricing or Direct Load Control? If so please provide us with these studies. If not, please explain why not.

RESPONSE:

Manitoba Hydro defines demand response programs as initiatives specifically intended to relieve capacity constraints during periods of peak system demand. Manitoba Hydro has not prepared specific reports related to demand response programs.

Currently, the need for new Manitoba Hydro generation resources is driven by future requirements for dependable energy supply, not by requirements to meet peak system loads. As a result, Manitoba Hydro has not experienced a strong driver to invest in programs or generation for capacity or load shifting purposes.

Demand response provides opportunity to reduce system demand during peak periods via curtailment of load and/or transfer of load to lower loading or off-peak periods. Such measures reduce system capacity requirements, but do not significantly reduce the overall energy requirements of participating customers, particularly where load shifting is enabled.

There may be export benefits from shifting loads to lower load off-peak periods, however the energy made available through demand response alone is generally viewed as insufficient to support the investment required to create and maintain a comprehensive Demand Response System program. By its nature, demand response is primarily a capacity tool.

Internal analysis and discussions with large customers served at sub-transmission and transmission levels have been undertaken in respect to time-of-use rates. The purposes of these discussions were not related to the demand response capability that such a rate structure may provide. The focus of these discussions was primarily on price signals related to domestic energy consumption and the relative value of that energy in the export market. As such, consideration for implementing time-of-use rates was focused more on longer term energy requirements and valuation rather than capacity requirements. Manitoba Hydro filed a Time-of-Use Rate application for General Service Large customers served at greater than 30 kV as part of its most recent General Rate Application. Consideration of that application by the Public Utilities Board is pending subject to a review of Manitoba Hydro's Cost-of-Service Study.

Manitoba Hydro's rate discussions have not progressed into studies on the benefits and costs of rate-related demand response programs such as Real Time Pricing and Critical Peak Pricing or Direct Load Control.

Please also refer to CAC/MH I-229b.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study

PREAMBLE: General/Current Demand Response Offerings

QUESTION:

Has Manitoba Hydro compared its current Demand Response offerings to its neighbouring jurisdictions? If so please provide documents related to this comparison. If not, please explain why not.

RESPONSE:

Manitoba Hydro has not prepared documents comparing its current demand response offerings (Curtailable Rates Program) to those of other jurisdictions. The design of Manitoba Hydro's Curtailable Rates Program is based on the specific needs and benefits for Manitoba Hydro, which may not be comparable to the specific needs and benefits of other jurisdictions. Such comparisons may therefore not provide particularly useful information, other than to establish comparative operational requirements and incentive values.

Please see Manitoba Hydro's response to CAC/GAC/MH I-030(b)

REFERENCE: Appendix 4.3 Demand Side Management Potential Study

PREAMBLE: General/Current Demand Response Offerings.

QUESTION:

Please confirm that the only Demand Response program currently offered by Manitoba Hydro is curtailable rates for industrial customers whose connected load exceeds 5,000 kilowatts. Please confirm if any new Demand Response program offerings are being developed and/or planned for the future for any sector (industrial, commercial, residential). If not, please explain why not.

RESPONSE:

The Curtailable Rates Program is the only demand response program offered by Manitoba Hydro. At present, no new demand response program offerings are under development. Please see Manitoba Hydro's response to CAC_GAC/MH I-030b.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study

PREAMBLE: General/Current Demand Response Offerings.

QUESTION:

The study "A National Assessment of Demand Response Potential" published by FERC in 2009 states that in 2014 the Demand Response (as a percentage of total load) for Minnesota, (a bordering state and significant export market for Manitoba Hydro) is 12% under a "Business as Usual" scenario and 15% as an achievable potential.

Using data from Manitoba Hydro's Electric Load Forecast and the 2013 - 2016 Power Smart Plan, Manitoba Hydro's Demand Response capability in 2014 as a percentage of total load will be approximately 3.6%. Please provide an explanation regarding the differences in outcomes between the current Minnesota Demand Response programs and Manitoba Hydro's Demand Response programs.

RESPONSE:

The 2009 FERC report is a potential study that provides an estimate of the demand response potential for peak system demand reduction in Minnesota (2014) under a “Business-as-Usual” scenario at approximately 12 percent with an “Achievable Participation” potential of approximately 15 percent. These values are identified as potential opportunities for demand response programs, rather than results from existing or planned programs. The report does state that the potential study includes estimates for existing programs, but it does not provide for the planned levels of reductions for these programs in either 2014 or 2019.

The 2013-16 Power Smart Plan identifies planned savings for the Curtailable Rates Program of approximately 161 MW at generation in 2014/15, or 3.44 percent of the projected Gross

Domestic System Peak of 4680 MW projected for this period in the 2013 Load Forecast. This planned level of savings in 2014/15 is not an estimate of demand response potential in Manitoba, but rather a planned level for an existing program based upon the current needs of the Corporation (please see Manitoba Hydro's response to CAC-GAC/MH I-030b). It should therefore not be used for comparative purposes with the potential estimates provided for in the FERC report.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study;

QUESTION:

How many Demand Response events did Manitoba Hydro call during 1) this year, 2) the previous 5 years, 3) the previous 10 years. What was the average load shed per event for each of the above time periods?

RESPONSE:

1) Manitoba Hydro has called 12 curtailments (demand response events) so far this fiscal year (2013/14) which have averaged 50 MW per curtailment.

2) Over the past 5 fiscal years (2008/09 to 2012/13) there have been a total of 37 curtailments, each averaging 53 MW.

3) Over the past 10 fiscal years (2003/04 to 2012/13) there have been 88 curtailments, each averaging 63 MW.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study

QUESTION:

Has Manitoba Hydro completed any studies comparing the benefit and costs of increasing Demand Response capacity rather than expanding generation? If so please provide these studies. If not, please explain why not.

RESPONSE:

Please refer to the responses for CAC-GAC/MH I-030b.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study

QUESTION:

Does MB have targets regarding the amount of DR capacity as a percentage of total load? If so please provide those targets. If not, please explain why not.

RESPONSE:

The 2013-16 Power Smart Plan provides planned demand reductions for the Curtailable Rates Program of approximately 147 MW from fiscal year 2015/16 through to the benchmark fiscal year of 2027/28. This level of savings at the meter equates to approximately 162 MW at generation.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study

QUESTION:

Please provide an explanation for the main objectives of Manitoba Hydro's current Demand Response program offerings. Please describe the circumstances for which Manitoba Hydro issues a Demand Response event.

RESPONSE:

The main objective of Manitoba Hydro’s Curtailable Rates Program is to maintain generation reserves, thereby minimizing disruptions to firm customers in the event of loss of generation or transmission, or an unexpected increase in firm load. A secondary objective is to fulfill Manitoba Hydro’s commitment to maintain a specific level of planning reserves and operating reserves as part of its reliability obligations with the Mid-Continent Area Power Pool – Generation Reserve Sharing Pool.

Dependent on the Curtailment Option selected by the participant, Manitoba Hydro will curtail customers in response to system emergencies and to maintain planning and operating reserves. Option A and C curtailable load will be used to meet reliability obligations only, Option R curtailable load will be used to maintain contingency reserves and Option E will be initiated to meet firm energy requirements.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study

QUESTION:

Please include an explanation with respect to how Demand Response is used in relation to: 1) maintaining system reserves, 2) preventing system shortages, 3) economic reasons.

RESPONSE:

Please refer to the response for CAC_GAC-0031g.

REFERENCE: Appendix 4.3 Demand Side Management Potential Study

QUESTION:

Does Manitoba Hydro foresee any changes in the future regarding its policies with respect to the above reasons? If so, please provide an explanation. If not, please explain why not.

RESPONSE:

Please see Manitoba Hydro's response to CAC-GAC/MH I-030b. As circumstances change, Manitoba Hydro will continue to review opportunities for future demand response programs.