Section:	Appendix 3 PCOSS 14	**Page No.:**	
Topic:	Marginal Costs		
Subtopic:	Marginal Energy Weighting		
Issue:	12 SEP Weighting		

PREAMBLE TO IR (IF ANY):

Current 12 SEP data used for weighting energy currently employs pre 2008/09 data.

QUESTION:

a) Please provide Manitoba Hydro's forecasted marginal values for generation and transmission by season and time period (peak, off-peak, shoulder). If required, the response can be filed in confidence.

b) Please provide the Surplus Energy Program prices for each of the 12 periods and for each of the years that are used in the calculation of the proxy prices used for calculating the energy weightings in PCOSS14 (in Excel format).

c) If different SEP prices are used in the calculation of proxy prices for calculating the energy weightings in PCOSS14 Amended compared to PCOSS14, please file the corresponding data for PCOSS14 Amended as filed in (b) (in Excel format).

d) Please make a comparison table showing the forecasted marginal values in (a) and the SEP-based proxy prices in (b) and (c) by period and show the variances.

e) Please file SEP-based proxy prices and supporting calculations for the energy weightings based on the use of only post-2008/09 SEP data.

RATIONALE FOR QUESTION:

To understand the impact of using more current information in the weighting of energy and capacity for establishing the allocation of energy and demand costs.

RESPONSE:

a) Manitoba Hydro does not prepare forecasted short run marginal values for the Surplus Energy Program (SEP) for the upcoming season and hence cannot provide the requested information.

The SEP Program is a revenue neutral program that offers customers choice and access to surplus energy at prices that reflect Manitoba Hydro's short term marginal cost of energy. Each Wednesday Manitoba Hydro applies to the Public Utilities Board for interim ex parte approval of the SEP Energy Rates to be in effect the following Monday through Sunday.

Each week, Manitoba Hydro does forecast short run marginal values for the Surplus Energy Program for the upcoming week, and these forecasts are filed immediately with the Public Utilities Board. Beyond the upcoming week, SEP short run marginal values are subject to near term weather variations and other uncertainties which make forecasting more difficult and less useful. The weather variations will tend to average out over multi-year periods.

b) Please see the Excel model titled 'Derivation of Energy Weights for PCOSS14.xlsx', provided on March 11, 2016.

c) The same SEP prices were used for PCOSS14 and PCOSS14-Amended.

d) As indicated in the response to part a), Manitoba Hydro does not prepare forecasts for SEP prices beyond the current week and is therefore unable to make the requested comparison of forecast to actual values.

e) The weightings used in PCOSS14 were based on eight years of SEP prices from April 1, 2004 to March 31, 2012. The model, noted above, was updated to include only SEP prices from April 1, 2009 to March 31, 2012, yielding updated weightings as follows:

Marginal Cost Weighting

	Peak	Shoulder	Off
Spring Season:	2.943	2.563	1.519
Summer Season:	3.588	2.424	1.000
Fall Season:	3.057	2.443	1.324
Winter Season:	3.897	2.885	2.154

Section:	PUB- MFR 9	**Page No.:**	
Topic:	Cost of Service Study		
Subtopic:	PCOSS08 - March 2009		
Issue:	Compliance with Board Directives from Orders 117/06 &116/08		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please file the complete PCOSS08 dated March 2009.

b) Please explain why MH believes that it is inconsistent from a cost causation principle to direct assign thermal plant costs to the Export Class, or to assign any fixed costs to opportunity sales.

RATIONALE FOR QUESTION:

To understand the impact of using the Board-directed methodology.

RESPONSE:

a) Much of PCOSS08 was previously provided in PUB MFR 8 and PUB MFR 9. The remaining PCOSS08 'Allocation Program' was provided in response to MIPUG/MH I-5.

b) Manitoba Hydro implemented an export class to moderate potentially unfair class revenue requirements that occur~~s~~ from incorporating significant revenue generated from selling surplus energy at market prices above embedded (original accounting costs) cost in the cost of service study. The cost of service study does not drive export rates. The intent of the export class is to give adequate cost recognition to exports such that the residual export revenue can be used to moderate the distortions.

The driver behind resources is the need to serve Manitoba load, in all conditions, at least cost. To meet Manitoba load reliably, Manitoba Hydro must put resources in place not

only to meet annual energy requirements, it must also put resources in place to meet the energy needs of its customers in every hour of the year (demand) and these requirements must be met even in lowest flow conditions. The outcome of this planning is that surplus energy is available temporarily in a hydraulic facility.

It is difficult, perhaps not possible, to precisely allocate cost to the export class given no facilities are driven by exports. To accommodate the allocation of cost to the export class for its intended purpose, Manitoba Hydro has elected to draw a distinction between the surplus energy types to recognize differences in the firmness, in other words differences in service levels. Manitoba Hydro has adopted a convention that dependable sales be assigned a full share of embedded cost responsibility. In PCOSS14-Amended, Manitoba Hydro has pooled all generation resources, including thermal (coal and natural gas) and hybrids, a pro-rata share of which has been allocated to dependable exports.

This cost treatment puts dependable exports on equal footing compared to domestic customers even though resources are put in place to serve Manitoba load and have priority to all output. And in some cases as discussed below, it would be reasonable to conclude based on cost causation that no cost assignment be made to exports. However, this treatment accommodates the following perspectives:

- in most conditions Manitoba Hydro intends to support its dependable export sales;
- some level of cost above variable costs may be incurred to export surplus;
- dependable exports may drive decisions to advance plant ahead of what is needed for Manitoba load; and
- undertaking export sales involves risk.

<u>Thermal Generation</u>

Thermal generation forms part of the generation portfolio of assets. Cost causation principles would require that only those costs attributed to a class would be assigned to that class. In the circumstance of thermal costs there are two types of costs, fixed costs and variable costs which potentially could be assignable.

With regard to embedded fixed costs Manitoba Hydro's treatment of thermal resources are no different than its other generation resources. These were put in place, some as many as 60 years ago, to serve Manitoba load. At that time they were routinely operated as a cost effective supply energy. However over time they have been used less and less

due to regulatory and cost issues, mainly in that less expensive supplies of electricity are available in the MISO market.

In today's environment, Manitoba Hydro's thermal resources serve three primary purposes. They are a source of capacity and dependable energy, both in the role as backstops to the hydraulic generating system which normally fills the needs of domestic load. A third purpose is to back up the transmission system by providing local Manitoba generation and voltage support in circumstances when the transmission system serving Manitoba load is threatened or out of service.

Capacity is required to serve peak demands and to satisfy Manitoba Hydro's minimum capacity planning criteria of 12%. Because of hydraulic generation's low variable cost, winter peak domestic demand is normally completely served from hydro capacity resources leaving thermal and import capacity resources in reserve. For example normal winter hydraulic generating output is 4,800 MW which on peak day is sufficient to supply all 4,700 MW of domestic load. Because all exports are curtailable to the extent necessary to serve domestic load, this normally leaves all thermal and import capacity resources available in reserve. So in the event of a major emergency such as on the HVDC system when access to significant hydro resources is lost, these capacity reserves can be called upon to maintain supply to Manitobans.

The energy needs of Manitoba are also almost completely met in normal circumstances from hydraulic generation. For example in 2014/15 hydraulic generation was 34,975 GWh which compares to domestic demand of 24,543 GWh. Again because all exports are curtailable to the extent necessary to serve domestic energy requirements, this normally leaves all thermal and import energy resources available in reserve. So in the event of a major drought, the dependable energy resources available from the thermal stations can be called upon to maintain supply to Manitobans.

But this raises the question of whether the dependable energy from the thermal stations enables Manitoba Hydro to enter into additional long term export sales that it would not if the thermal resources were not there. The answer to that question is no. All recent long term sales are supported by dependable energy and capacity resources supplied by the purchaser (i.e. hybrid sales) or they were negotiated based upon Manitoba Hydro's commitment to build new hydro facilities which provide sufficient new hydraulic dependable energy and capacity (i.e. Keeyask and the 250 MW MP sale, the 125 NSP

sale, the 100 MW WPS sale and the 100 MW SaskPower sale). Export customers have no interest in sales agreements from MH's dependable wind or dependable thermal resources.

So from the three perspectives, capacity, energy and local generation support, the only role for Manitoba thermal resources is to provide service to domestic customers. And therefore there is no reason, from a cost causation perspective, to assign or allocate any thermal generation costs to the export class.

With regard to assigning variable costs associated with thermal station operation to the export class, there could be justification from a cost causation perspective to do so if it was normal for the thermal stations to be dispatched to serve export opportunities. However given regulatory restrictions and the very expensive cost of thermal generation in Manitoba, it rarely makes financial sense to make incremental exports using Manitoba Hydro's thermal units. Rather in times when the hydraulic system is short of energy, purchases from MISO are usually 50% or more less costly than burning natural gas at the thermal stations. For that reason there is no cost causation justification to charge any of MH's thermal generation variable costs to exports. All these costs are most appropriately charges to domestic load.

Opportunity Sales

Similar to the earlier discussion on thermal costs, cost causation principles would require that only those costs attributed to opportunity sales would be assigned to that class. As opportunity sales may be supported by variable costs, they should be assigned to the opportunity sales.

To the extent that Manitoba Hydro were to make investments, and as a result incur embedded costs in order to secure opportunity sales, cost causation principles would require that those embedded costs be assigned or allocated to the opportunity class. However, because the vast majority of Manitoba Hydro's embedded costs have been incurred for the purpose of meeting Manitoba firm load and energy needs, cost causation principles do not support any assignment of embedded costs to opportunity sales.

In the short run relative to the long life of Manitoba Hydro's generation and transmission assets there may be firm capacity and dependable energy surpluses available that can be used to support firm export sales. In that circumstance Manitoba Hydro could support an

allocation of a share of embedded costs to firm exports and has done so in its cost of service methodology.

There are reasonable arguments for allocating less than a full pro-rata share of embedded costs to dependable exports. Firm exports are not equivalent to firm domestic load in many ways but for simplicity reasons they are treated in the PCOSS as if they were. In a comparison, domestic customers would pick up greater cost responsibility than a pro-rata share for the following reasons:

- All energy is for Manitobans first (please see Manitoba Hydro's response to COALITION/MH I-22a-h)
- Manitoba Hydro carries planning, regulating and contingency reserves for domestic load
- Manitobans receive priority transmission service on the HVDC system
- Individual Manitoba customers have no requirement on a long term basis to financially commit to Manitoba Hydro (firm export contracts are take or pay)

As a result of these factors treating firm export load on an equivalent basis as firm domestic load over allocates costs to the firm export load. In this circumstance, to assign full embedded costs to opportunity sales is extremely difficult to rationalize and cannot be supported. This would result in an equal cost framework for all exports and domestic customers even though the levels of service range significantly. Opportunity sales result from salvaging temporary energy and capacity unused by Manitobans which are made from water flows which cannot be reliably counted on. Dependable sales, while largely firm, do not take priority over Manitoba load, and also are provided a lower level of service. There is no discretion in providing service to domestic customers for whom the system is built and provided service on demand in all conditions.

The allocation of cost to an export class, regardless of the rationale used, impacts only domestic customer cost responsibility. The allocation of cost to the export class has no bearing on export rates as export rates are determined in the competitive market. Manitoba Hydro's treatment has resulted in a demarcation point drawn where approximately half of its export sales are costed out on an equivalent basis as domestic customers. The other half are treated as a by-product and assigned variable cost. To go further risks over allocating cost to exports, which are actually a net benefit of selling at market prices above embedded cost. More importantly, the result would be to under-

allocate embedded cost to domestic customer classes and the flexibility lost to use the residual NER to moderate the potentially unfair class revenue requirements.

Section:	PUB- MFR 9	**Page No.:**	page 3
Topic:	Cost of Service Study		
Subtopic:	DSM cost allocation		
Issue:	Compliance with Board Directives		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please indicate to what extent the forecast share of DSM class savings has changed since PCOSS08 and explain what factors have resulted in any changes in allocation by customer class.

b) Please indicate to what extent MH is tracking savings by customer class for current and new targeted DSM programs.

c) Please provide a table indicating the DSM forecast savings by customer class in each successive PCOSS since PCOSS08.

d) Please provide a table indicating the DSM forecast savings by customer class and reconcile with DSM savings by sector in the Power Smart Plan in PCOSS14 Amended.

RATIONALE FOR QUESTION:

To understand the allocation of DSM savings in the PCOSS.

RESPONSE:

a) The response to part c) outlines the changes in the share of DSM class savings since PCOSS08. The allocation by customer class is based on the forecast energy savings in the Power Smart Plan each year, which forecast energy savings are developed based on updated information about the market. In general the changes to the allocation by

customer class are minimal, with the current PCOSS14 forecast share of DSM savings in each customer class being +/- 5% different from those used in PCOSS08.

b) Manitoba Hydro tracks actual savings achieved through DSM programs by customer sector. As there is only one residential rate class, energy savings resulting from DSM programs are available for this rate class. For the commercial and industrial sector, the energy savings resulting from current and new DSM programs is estimated based on the rate class distribution of the applicable target market for that particular program.

c) The table below shows the forecast DSM savings by customer class for PCOSS prepared since PCOSS08.

	PCOSS08	PCOSS08	PCOSS10	PCOSS11	PCOSS13	PCOSS14	PCOSS14
	Response Order 117/06	Response 116/08			Methodology Changes		Amended
	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
	DSM KW.h	DSM KW.h	DSM KW.h	DSM KW.h	DSM KW.h	DSM KW.h	DSM KW.h
	Savings	Savings	Savings	Savings	Savings	Savings	Savings
GSS ND	28,471,900	28,471,900	23,568,128	39,915,532	28,453,512	16,843,257	16,843,257
GSS D	29,584,900	29,584,900	37,607,114	37,235,073	37,820,899	28,115,316	28,115,316
GSM	38,282,780	38,282,780	43,845,243	64,042,794	41,789,884	28,432,707	28,432,707
GSL 0-30	24,523,120	24,523,120	24,233,631	37,671,495	22,668,702	13,856,728	13,856,728
GSL 30-100	2,327,780	2,327,780	2,444,554	6,771,513	12,979,369	6,359,917	6,359,917
GSL >100	10,469,520	10,469,520	7,078,850	44,066,455	72,125,277	16,737,293	16,737,293
Res	42,040,000	42,040,000	42,472,480	159,699,008	45,239,771	41,215,066	41,215,066
A&R Lighting	-	-	-	-	-	-	-
Total	175,700,000	175,700,000	181,250,000	389,401,870	261,077,414	151,560,284	151,560,284

d) The following table provides the DSM savings by class for each Power Smart program which reconcile with the 2012 DSM savings shown in PCOSS14 Amended. These figures can also be found in Appendix A.2 “2012/13 Power Smart Annual Energy Savings (GWh)” in the 2013/14 column, which is provided as Attachment 2 in response to PUB/MH I-59b.

2013/14 DSM Energy Savings By Program By Class (kWh)

Program	Total Program Energy Savings	Small Demand <50 kVA	Small Demand >50 kVA	Medium Demand	Large Demand <30 kV	Large Demand 30-100 kV	Large Demand >100 kV	Residential
Performance Optimization	19,866,593	0	993,330	4,966,648	5,959,978	3,973,319	3,973,319	0
Bio-energy Optimization	15,546,442	0	621,858	932,787	777,322	777,322	12,437,154	0
Commercial Lighting	34,608,246	9,517,268	9,517,268	9,240,402	4,602,897	1,453,546	276,866	0
Commercial Custom Measures	1,518,646	37,966	607,458	759,323	75,932	37,966	0	0
Commercial Windows	3,263,624	1,142,268	1,142,268	815,906	130,545	32,636	0	0
Commercial Chillers	1,451,069	0	0	623,960	827,110	0	0	0
Parking Lot Controllers	2,242,722	784,953	784,953	538,253	89,709	22,427	22,427	0
Comm. Refrigeration	1,923,865	480,966	480,966	961,933	0	0	0	0
Comm. Insulation	3,517,371	1,231,080	1,231,080	879,343	140,695	35,174	0	0
Comm. Earth Power	2,805,466	981,913	1,066,077	673,312	56,109	14,027	14,027	0
New Buildings	15,255,259	1,525,526	9,381,984	3,966,367	381,381	0	0	0
City of Wpg PS Agreement	377,927	377,927	0	0	0	0	0	0
Comm. Building Optimization	1,615,024	0	293,934	881,803	439,287	0	0	0
Comm. Rinse and Save	1,999	1,099	600	300	0	0	0	0
Comm. Kitchen Appliances	412,694	90,793	214,601	103,174	4,127	0	0	0
Comm. Clothes Washers	178,158	83,200	38,393	54,819	0	873	873	0
Network Energy Management	2,446,300	122,315	122,315	2,201,670	0	0	0	0
CO2 Sensors	187,413	0	52,663	124,442	10,308	0	0	0
Internal Retrofit	1,262,693	391,435	391,435	391,435	63,135	12,627	12,627	0
Agricultural Heat Pad	1,863,704	74,548	1,174,133	316,830	298,193	0	0	0
Refrigerator Retirement	23,845,324	0	0	0	0	0	0	23,845,324
Water and Energy Saver	4,801,332	0	0	0	0	0	0	4,801,332
Power Smart Res. Loan	584,897	0	0	0	0	0	0	584,897
Solar Water Heaters	2,481,377	0	0	0	0	0	0	2,481,377
Home Insulation	5,610,680	0	0	0	0	0	0	5,610,680
Lower Income	3,891,457	0	0	0	0	0	0	3,891,457
Total	151,560,283	16,843,257	28,115,316	28,432,707	13,856,728	6,359,917	16,737,293	41,215,066

Section:	PUB- MFR 9	**Page No.:**	page 3
Topic:	Cost of Service Study		
Subtopic:	DSM cost allocation		
Issue:	Compliance with Board Directives		

PREAMBLE TO IR (IF ANY):

QUESTION:

e) Please provide the supporting tables in the form of tables 1, 2, and 3 from PUB MFR 9 to support the changed energy assignments by customer class since PCOSS08 and explain any changes in PCOSS14.

RATIONALE FOR QUESTION:

To understand the allocation of DSM savings in the PCOSS.

RESPONSE:

The tables below show the analysis used to convert the cumulative DSM savings tracked by sector into an estimate of class-by-class savings for use in the PCOSS. The approach used in PCOSS14 is consistent with that used in PCOSS08, with class share of forecast sector savings in PCOSS14 based on six studies instead of the four studies previously used.

Table 1 – Cumulative DSM Energy Savings Forecast to 2013/14 (GWh @ Generation)

	Program Savings by Sector	Codes & Standards Savings Attributed to Sectors	Total Savings by Sector
Residential	303	475	778
Industrial	503	-	503
Commercial (less A&R Lighting)	648	167	815
A&R Lighting	43		43
Total Energy Savings	1,497	641	2,138

Table 2 – Average Class Share of Forecast Sector Savings in PCOSS

	GSS ND	GSS D	GSM	GSL 0-30	GSL 30-100	GSL >100	Res	A&R Lighting	Total
Industrial	1.7%	2.4%	19.8%	20.6%	5.8%	49.8%	0.0%	0.0%	100%
Commercial	25.5%	29.5%	33.8%	8.8%	1.5%	0.6%	0.4%	0.0%	100%

Table 3 – Sector Energy Savings Assigned to Classes (GW.h @ Generation)

	GSS ND	GSS D	GSM	GSL 0-30	GSL 30-100	GSL >100	Res	A&R Lighting	Total
Residential							778		778
Industrial	8	12	100	104	29	251	-		503
Commercial	208	241	275	72	12	5	3		815
A&R Lighting								43	43
Total Savings	216	252	375	175	41	256	781	43	2,138

Section:	PCOSS 14; PUB MFR 9	**Page No.:**	page 50-51
Topic:	Development of Class Loads		
Subtopic:	DSM Allocation		
Issue:	DSM Savings Allocation		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a table of cumulative DSM savings forecast at Generation, Average Class Share of forecast savings, and the assignment to the customer class of both energy and capacity used in PCOSS14 Amended and compare with that used in PCOSS08 (PUB MFR 9) and explain any differences.

b) Please describe any changes to the method of DSM savings assignment other than those described in MFR 9.

RATIONALE FOR QUESTION:

RESPONSE:

a) Please see the tables below.

	PCOSS14 116/08	PCOSS08 116/08	PCOSS08-PCOSS14	PCOSS14-Amended	PCOSS14-Amended
	Cumulative Energy at Generation (GW.h) to 2013/14	Cumulative Energy at Generation (GW.h) To 2007/08	Average Forecast Energy at Meter (GW.h)	Forecast Energy at Meter (GW.h)	Forecast Demand at Meter (MW)
GSS ND	216	148	27	17	4.5
GSS D	252	157	34	28	6.9
GSM	375	259	43	28	6.8
GSL 0-30	175	112	25	14	2.7
GSL 30-100	41	30	6	6	1.2
GSL >100	256	206	30	17	2.1
Residential	781	396	66	41	8.5
A&R Lighting	43	43	-	-	-
Total	2,139	1,351	231	151	32.7

	PCOSS14 116/08	PCOSS08 116/08	PCOSS08-PCOSS14	PCOSS14-Amended	PCOSS14-Amended
	Class Share of Cumulative Energy at Generation to 2013/14	Class Share of Cumulative Energy at Generation To 2007/08	Class Share of Average Forecast Energy at Meter	Class Share of Forecast Energy at Meter	Class Share of Forecast Demand at Meter
GSS ND	10%	11%	12%	11%	14%
GSS D	12%	12%	15%	19%	21%
GSM	18%	19%	19%	19%	21%
GSL 0-30	8%	8%	11%	9%	8%
GSL 30-100	2%	2%	3%	4%	4%
GSL >100	12%	15%	13%	11%	6%
Residential	37%	29%	29%	27%	26%
A&R Lighting	2%	3%	0%	0%	0%
Total	100%	100%	100%	100%	100%

Please see Manitoba Hydro's response to PUB/MH I-3a for a discussion of the changes in class DSM savings between PCOSS08 and PCOSS14.

b) The method of assigning forecast DSM energy and demand savings to domestic classes has not changed between PCOSS08 and PCOSS14-Amended.

Section:	Appendix 3.1, PCOSS14	**Page No.:**	pg. 48-49
Topic:	Load Forecast		
Subtopic:	Demand Allocation		
Issue:	Coincident & Non-Coincident Peak Load Forecast		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please file copies of all the Peak Load Responsibility Studies used to determine the average results for class demand PCOSS14 Amended and PCOSS08 (Mar 2009) for coincident peak and non-coincident peaks. Please provide the supporting calculations for the averages.

b) Please explain the correction in the definition in peak hours.

c) Please provide the supporting calculations for the average seasonal class demand.

d) For the energy allocators (E12) and (E13) and demand allocators (D13) and (D14), please provide the allocation percentages by class and subclass, similar to that provided in MIPUG/MH I-23 (a) in the 2010/11 & 2011/12 GRA Proceeding.

RATIONALE FOR QUESTION:

To understand the reasonableness of the averages used in forecast energy and peak demand weightings.

RESPONSE:

Response to parts a) to d):

PCOSS08 (116/08) dated March 2009 used results from the 2005/06 Load Research study to estimate coincident peaks as well as non-coincident peaks.

In PCOSS10 Manitoba Hydro introduced the use of averaged results from multiple Load Research studies to minimize year-to-year variation in the factors used to estimate class demand. In PCOSS14-Amended factors used to estimate non-coincident peaks are based on the eight year average of 2004/05 to 2011/12 Load Research studies. The calculation of the class averages as used in Schedule D5-Amended are shown below.

Calculation of Class Average Coincident Peak Load Factor

Load Research Study	Residential	GS Small Non Demand	GSS Demand	GS Medium	GSL 750-30kV	GS Large 30-100kV	GS Large 30-100 kV Curtailable	GS Large > 100kV	GS Large > 100 kV Curtailable	GS Medium SEP	GS Large Sep
04/05	49.0%	64.4%	60.8%	70.1%	78.4%	96.1%	101.4%	90.2%	100.4%	51.3%	70.5%
05/06	53.6%	61.6%	68.1%	73.6%	81.2%	83.2%	98.0%	87.0%	97.3%	44.8%	88.8%
06/07	51.1%	61.0%	67.6%	72.6%	79.7%	92.4%	104.9%	93.6%	97.4%	49.4%	74.7%
07/08	51.4%	61.1%	65.4%	73.0%	80.3%	92.4%	96.6%	93.2%	98.6%	43.1%	88.5%
08/09	50.2%	61.7%	66.4%	72.4%	80.2%	85.9%	96.7%	95.5%	103.6%	46.5%	105.5%
09/10	47.9%	60.0%	66.3%	72.6%	79.0%	96.0%	96.9%	92.3%	97.5%	50.7%	146.9%
10/11	50.6%	64.4%	67.5%	73.0%	79.3%	89.0%	96.2%	87.5%	94.1%	45.3%	137.3%
11/12	50.7%	62.0%	65.8%	72.0%	78.5%	93.1%	100.8%	88.4%	105.8%	43.8%	218.0%
Average	50.5%	62.0%	66.0%	72.4%	79.6%	91.0%	98.9%	91.0%	99.3%	46.9%	116.3%

Calculation of Class Average Coincident Factors

Load Research Studies	Residential	GS Small Non Demand	GSS Demand	GS Medium	GSL 750-30kV	GS Large 30-100kV	GS Large 30-100 kV Curtailable	GS Large > 100kV	GS Large > 100 kV Curtailable	GS Medium SEP	GS Large Sep
04/05	91.7%	84.1%	88.7%	92.7%	87.8%	71.8%	91.6%	90.7%	83.3%	78.6%	21.3%
05/06	87.8%	83.0%	87.2%	90.6%	84.2%	77.7%	94.1%	91.8%	95.8%	78.7%	18.0%
06/07	90.5%	88.5%	89.2%	91.6%	89.1%	72.2%	89.1%	86.1%	56.2%	68.8%	17.8%
07/08	89.6%	88.7%	92.5%	92.8%	88.7%	72.4%	96.3%	90.6%	84.4%	81.6%	17.6%
08/09	92.1%	84.8%	89.6%	89.9%	90.6%	83.2%	90.4%	83.2%	83.5%	81.7%	12.7%
09/10	91.5%	86.0%	90.5%	90.5%	92.1%	72.1%	95.9%	86.2%	78.0%	77.1%	8.8%
10/11	89.1%	88.5%	91.4%	92.2%	91.0%	69.9%	98.8%	85.9%	87.6%	90.6%	11.0%
11/12	89.2%	86.4%	89.5%	91.9%	91.3%	73.0%	92.4%	84.6%	80.5%	90.8%	7.3%
Average	90.2%	86.3%	89.8%	91.5%	89.3%	74.0%	93.6%	87.4%	81.2%	81.0%	14.3%

Prior to the 2011/12 Load Research study, system peak was defined as the average of the top 50 Generation Peak times including hydraulic and thermal generation and excluding wind generation and imports. Excluding wind generation and imports from the determination of peak hours was consistent with the resources included in the generation pool in previous versions of the Cost of Service Study which assigned wind generation and imports costs

directly to the Export Class, but was inconsistent with current use of the load research results based on generation peaks only in the allocation of Transmission costs.

PCOSS14-Amended used only the single year of Load Research for 2011/12, which incorporated wind and imports into definition of peak, to estimate the seasonal class coincident-peak demands. Future studies will be based on the average of the past eight years of Load Research results, which will be phased in as data becomes available.

The following tables show class share of Weighted Energy and 2CP Demand for PCOSS14-Amended as percentages:

	E12 Weighted Energy	E13 Weighted Energy	D14 2CP Demand	D13 2CP Demand
Residential	28.8%	25.0%	32.6%	28.8%
Residential Seasonal	0.3%	0.3%	0.2%	0.2%
Residential FRWH	0.1%	0.0%	0.0%	0.0%
GSS Non Demand	6.3%	5.5%	7.0%	6.2%
GSS Demand	7.9%	6.9%	8.3%	7.3%
GSS Seasonal	0.0%	0.0%	0.0%	0.0%
GSS FRWH	0.0%	0.0%	0.0%	0.0%
GSM	12.2%	10.6%	12.7%	11.2%
GSL 0-30kV	6.4%	5.6%	6.6%	5.8%
GSL 30-100kV	4.7%	4.0%	4.1%	3.6%
GSL >100kV	16.9%	14.7%	14.3%	12.6%
A&R Lighting	0.3%	0.3%	0.2%	0.2%
Exports	16.0%	27.2%	14.0%	24.1%
Total	100.0%	100.0%	100.0%	100.0%

The eight years of Load Research at common bus peak, as well as the two years of Load Research at generation peak, used in PCOSS08 (Order 116/08) and PCOSS14-Amended are attached to this response.

Load Research Results Average 2004/2005
Corresponding to Highest 50 System Loads

	Customer Months	Billed Energy	Average Energy	CP Load kW	Avg CP Load	CP Load Factor	NCP Load	Winter CF
Residential	420,832	6,274,665,862	14,910	1,462,736	3.5	48.97%	1,595,048	91.7%
GS Small Non Demand	51,260	1,399,998,170	27,312	248,267	4.8	64.37%	295,134	84.1%
GS Small Demand	7,575	1,824,915,571	240,902	342,842	45.3	60.76%	387,647	88.4%
GS Small Demand LUBD	75	6,688,980	89,286	915	12.2	83.49%		
GSS Demand (Incl LUBD)	7,650	1,831,604,551	239,418	343,757	44.9	60.82%	387,647	88.7%
GS Medium	1,730	2,851,470,222	1,647,852	464,593	268.5	70.06%	502,346	92.5%
GS Medium LUBD	22	6,556,950	294,694	896	40.3	83.49%		
GSM (Incl LUBD)	1,753	2,858,027,172	1,630,674	465,490	265.6	70.09%	502,346	92.7%
GS Medium SEP	25	22,929,389	917,176	5,106	204.3	51.26%	6,495	78.6%
GS Large 750-30 kV	227	1,485,870,317	6,543,282	216,464	953.2	78.36%	246,673	87.8%
GS Large 750-30 kV LUBD	15	1,101,460	71,446	151	9.8	83.49%		
GSL 750-30kV (Incl LUBD	243	1,486,971,777	6,131,842	216,615	893.3	78.36%	246,673	87.8%
GS Large 750-30 kV SEP	6	2,442,943	407,157	396	65.9	70.48%	1,859	21.3%
GS Large 30-100kV	28	556,347,390	19,869,550	66,061	2,359.3	96.14%	92,025	71.8%
GS Curtailable 30-100kV	1	226,081,148	226,081,148	25,444	25,444.2	101.43%	27,779	91.6%
GS Large 30-100 Total	29	782,428,538	26,980,294	91,505	3,155.3	97.61%	118,735	
GS Large > 100kV	12	2,644,983,326	220,415,277	334,896	27,908.0	90.16%	369,097	90.7%
GS Curtailable >100kV	3	2,225,818,941	741,939,647	253,103	84,367.7	100.39%	303,961	83.3%
GS Large > 100kV Total	14	4,870,802,267	341,810,685	587,999	41,263.1	94.56%	664,609	

Load Research Results Average 2005/2006
Corresponding to Highest 50 Winter Common Bus Peaks

	Customer Months	Billed Energy	Average Energy	CP Load kW Nov-Apr 00:00 to 24:00	Avg CP Load	CP Load Factor	Annual NCP	Annual CF
Residential	423,783	6,170,740,484	14,561	1,313,953	3.10	53.6%	1,496,828	87.8%
GS Small Non Demand	50,197	1,320,845,519	26,313	244,727	4.88	61.6%	295,021	83.0%
GS Small Demand	9,057	1,924,218,362	212,464	322,321	35.59	68.1%	369,537	87.2%
GS Small Demand LUBD	74	6,564,662	88,712	963	13.01	77.8%		
GS Medium	1,754	2,853,801,244	1,627,025	442,453	252.25	73.6%	488,206	90.6%
GS Medium LUBD	23	6,578,874	285,005	965	41.81	77.8%		
GS Medium SEP	23	20,703,086	920,137	5,278	234.60	44.8%	6,710	78.7%
GS Large 750-30 kV	233	1,529,944,656	6,554,565	215,192	921.92	81.2%	255,686	84.2%
GS Large 750-30 kV LUBD	17	1,378,190	81,070	202	11.89	77.8%		
GS Large 750-30 kV SEP	6	2,643,832	440,639	340	56.67	88.8%	1,887	18.0%
GS Large 30-100kV	26	555,116,514	21,350,635	76,140	2,928.47	83.2%	98,041	77.7%
GS Curtailable 30-100kV	1	220,647,742	220,647,742	25,707	25,706.91	98.0%	27,306	94.1%
GS Large 30-100 Total	27	775,764,256	28,468,413	101,847	3,737.51	87.0%	124,597	81.7%
GS Large > 100kV	12	2,635,795,910	219,649,659	345,830	28,819.18	87.0%	376,607	91.8%
GS Large > 100 kV LUBD	1	216,000	216,000	32	31.69	77.8%		
GS Curtailable >100kV	3	2,479,408,333	826,469,444	290,947	96,982.22	97.3%	303,857	95.8%
GS Large > 100kV Total	15	5,115,420,243	341,028,016	636,808	42,453.90	91.7%	680,313	93.6%

Load Research Results Average 2006/2007
Corresponding to Highest 50 Overall Common Bus Peaks

	Average Metered Customer Years	Total Energy	Average Energy	CP Load kW Jan-Dec 06:00 to 22:00	Avg CP Load	CP Load Factor	NCP Load Jan-Dec 00:00 to 24:00	Overall CF
Residential	431,980	6,456,918,076	14,947	1,443,361	3.34	51.1%	1,594,518	90.5%
GS Small Non Demand	46,598	1,191,147,217	25,562	222,834	4.78	61.0%	251,906	88.5%
GS Small Demand	11,449	2,126,258,769	185,716	359,034	31.36	67.6%	402,697	89.2%
GS Medium	1,823	3,013,981,578	1,653,309	474,283	260.17	72.6%	517,801	91.6%
GS Medium SEP	22	21,634,743	983,397	5,000	227.28	49.4%	7,267	68.8%
GS Medium Total	1,845	3,035,616,321	1,645,320	479,283	259.77	72.3%		
GS Large 750-30 kV	235	1,534,922,201	6,531,584	219,777	935.22	79.7%	246,771	89.1%
GS Large Sep	6	2,164,557	360,760	331	55.11	74.7%	1,853	17.8%
GS Large 750-30 kV Total	241	1,537,086,758	6,377,953	220,107	913.31	79.7%		
GS Large 30-100 kV	26	648,412,319	24,938,935	80,105	3,080.97	92.4%	111,001	72.2%
GS Large 30-100 kV Curtailable	1	219,949,755	219,949,755	23,933	23,933.44	104.9%	26,856	89.1%
GS Large 30-100 Total	27	868,362,074	32,161,558	104,039	3,853.28	95.3%		
GS Large > 100 kV	11	2,655,938,640	241,448,967	324,084	29,462.17	93.6%	376,200	86.1%
GS Large > 100 kV Curtailable	3	2,420,903,594	806,967,865	288,890	96,296.78	95.7%	303,030	95.3%
GS Large > 100kV Total	14	5,076,842,234	362,631,588	612,974	43,783.88	94.6%		

Load Research Results Average 2007/2008
Corresponding to Highest 50 Overall Common Bus Peaks

	Average Metered Customer Years	Total Energy	Average Energy	CP Load kW Jan-Dec 06:00 to 22:00	Avg CP Load	CP Load Factor	NCP Load Jan-Dec 00:00 to 24:00	Overall CF
Residential	435,878	6,751,319,619	15,489	1,495,952	3.43	51.4%	1,670,098	89.6%
GS Small Non Demand	51,708	1,548,413,306	29,945	288,411	5.58	61.1%	325,061	88.7%
GS Small Demand	6,722	1,887,396,024	280,779	328,498	48.87	65.4%	355,005	92.5%
GS Medium	1,837	3,059,916,004	1,665,714	477,494	259.93	73.0%	514,311	92.8%
GS Medium SEP	19	20,632,994	1,085,947	5,447	286.68	43.1%	6,674	81.6%
GS Large 750-30 kV	254	1,549,251,324	6,099,415	219,506	864.20	80.3%	247,486	88.7%
GS Large 750-30 kV SEP	5	2,883,632	576,726	371	74.18	88.5%	2,106	17.6%
GS Large 30-100 kV	27	689,403,141	25,533,450	84,949	3,146.27	92.4%	117,387	72.4%
GS Large 30-100 kV Curtailable	1	218,136,713	218,136,713	25,713	25,712.50	96.6%	26,692	96.3%
GS Large 30-100 Total	28	907,539,854	32,412,138	110,662	3,952.20	93.4%		
GS Large > 100 kV	12	2,757,803,002	229,816,917	336,837	28,069.79	93.2%	371,978	90.6%
GS Large > 100 kV Curtailable	3	2,395,238,017	798,412,672	276,515	92,171.74	98.6%	327,766	84.4%
GS Large > 100kV Total	15	5,153,041,019	343,536,068	613,353	40,890.18	95.6%		

Load Research Results Average 2008/2009
Corresponding to Highest 50 Overall Common Bus Peaks

	Average Metered Customer Years	Total Energy	Average Energy	CP Load kW Jan-Dec 06:00 to 22:00	Avg CP Load	CP Load Factor	NCP Load Jan-Dec 00:00 to 24:00	Overall CF
Residential	440,635	6,894,690,072	15,647	1,568,317	3.56	50.2%	1,703,125	92.1%
GS Small Non Demand	51,936	1,571,741,845	30,263	290,843	5.60	61.7%	342,999	84.8%
GS Small Demand	6,773	1,903,094,633	280,983	326,975	48.28	66.4%	365,111	89.6%
GS Medium	1,824	3,027,924,298	1,660,046	477,610	261.85	72.4%	531,151	89.9%
GS Medium SEP	19	19,765,261	1,040,277	4,856	255.59	46.5%	5,945	81.7%
GS Medium Total	1,843	3,047,689,559	1,653,657	482,467	261.78	72.1%		
GS Large 750-30 kV	254	1,551,755,741	6,109,275	220,816	869.35	80.2%	243,843	90.6%
GS Large Sep	5	2,579,646	515,929	279	55.85	105.5%	2,197	12.7%
GS Large 750-30 kV Total	259	1,554,335,387	6,001,295	221,095	853.65	80.3%		
GS Large 30-100 kV	27	730,061,703	27,039,322	96,973	3,591.59	85.9%	116,623	83.2%
GS Large 30-100 kV Curtailable	1	205,929,399	205,929,399	24,299	24,298.74	96.7%	26,873	90.4%
GS Large 30-100 Total	28	935,991,102	33,428,254	121,272	4,331.13	88.1%		
GS Large > 100 kV	12	2,671,365,410	222,613,784	319,330	26,610.84	95.5%	383,827	83.2%
GS Large > 100 kV Curtailable	3	2,477,205,649	825,735,216	273,086	91,028.78	103.6%	326,880	83.5%
GS Large > 100kV Total	15	5,148,571,059	343,238,071	592,416	39,494.43	99.2%		

Load Research Results Average 2009/2010
Corresponding to Highest 50 Overall Common Bus Peaks

	Average Metered Customer Years	Total Energy	Average Energy	CP Load kW Jan-Dec 06:00 to 22:00	Avg CP Load	CP Load Factor	NCP Load Jan-Dec 00:00 to 24:00	Overall CF
Residential	444,958	6,737,287,223	15,141	1,607,300	3.61	47.9%	1,757,342	91.5%
GS Small Non Demand	52,125	1,535,462,020	29,457	292,079	5.60	60.0%	339,614	86.0%
GS Small Demand	6,889	1,870,052,508	271,455	322,047	46.75	66.3%	355,934	90.5%
GS Medium	1,881	2,992,397,556	1,590,855	470,595	250.18	72.6%	519,929	90.5%
GS Medium SEP	19	18,390,773	967,935	4,140	217.90	50.7%	5,371	77.1%
GS Medium Total	1,900	3,010,788,329	1,584,625	474,735	249.86	72.4%		
GS Large 750-30 kV	262	1,536,723,025	5,865,355	222,133	847.84	79.0%	241,158	92.1%
GS Large Sep	4	1,631,852	407,963	127	31.70	146.9%	1,434	8.8%
GS Large 750-30 kV Total	266	1,538,354,877	5,783,289	222,260	835.56	79.0%		
GS Large 30-100 kV	28	737,569,448	26,341,766	87,750	3,133.94	96.0%	121,780	72.1%
GS Large 30-100 kV Curtailable	1	219,939,730	219,939,730	25,913	25,912.94	96.9%	27,011	95.9%
GS Large 30-100 Total	29	957,509,178	33,017,558	113,663	3,919.42	96.2%		
GS Large > 100 kV	12	2,473,855,318	206,154,610	306,096	25,508.00	92.3%	355,050	86.2%
GS Large > 100 kV Curtailable	3	2,050,320,681	683,440,227	240,133	80,044.31	97.5%	307,677	78.0%
GS Large > 100kV Total	15	4,524,175,999	301,611,733	546,229	36,415.26	94.5%		

Load Research Results Average 2010/2011
Corresponding to Highest 50 Overall Common Bus Peaks

	Average Metered Customer Years	Total Energy	Average Energy	CP Load kW Jan-Dec 06:00 to 22:00	Avg CP Load	CP Load Factor	NCP Load Jan-Dec 00:00 to 24:00	Overall CF
Residential	448,867	6,737,250,345	15,009	1,521,212	3.39	50.6%	1,706,728	89.1%
GS Small Non Demand	52,385	1,576,123,536	30,087	279,302	5.33	64.4%	315,467	88.5%
GS Small Demand	7,056	1,930,293,411	273,568	326,415	46.26	67.5%	357,204	91.4%
GS Medium	1,887	3,060,995,602	1,622,149	478,814	253.74	73.0%	519,043	92.2%
GS Medium SEP	16	22,299,604	1,393,725	5,623	351.45	45.3%	6,210	90.6%
GS Medium Total	1,903	3,083,295,206	1,620,229	484,438	254.57	72.7%		
GS Large 750-30 kV	269	1,599,193,401	5,944,957	230,319	856.20	79.3%	253,023	91.0%
GS Large Sep	3	2,086,967	695,656	173	57.82	137.3%	1,576	11.0%
GS Large 750-30 kV Total	272	1,601,280,368	5,887,060	230,493	847.40	79.3%		
GS Large 30-100 kV	35	778,414,269	22,240,408	99,885	2,853.85	89.0%	142,918	69.9%
GS Large 30-100 kV Curtailable	1	225,799,769	225,799,769	26,797	26,796.82	96.2%	27,128	98.8%
GS Large 30-100 Total	36	1,004,214,038	27,894,834	126,682	3,518.93	90.5%		
GS Large > 100 kV	12	2,549,483,703	212,456,975	332,518	27,709.82	87.5%	386,921	85.9%
GS Large > 100 kV Curtailable	3	1,864,427,156	621,475,719	226,217	75,405.65	94.1%	258,281	87.6%
GS Large > 100kV Total	15	4,413,910,859	294,260,724	558,735	37,248.99	90.2%		

Load Research Results Average 2011/2012
Corresponding to Highest 50 Overall Common Bus Peaks

	Average Annual Metered Customers	Total Energy (kWh)	Average Energy (kWh)	Coincident Peak Load Jan-Dec 06:00 to 22:00 (kW)	Avg Coincident Peak Load (kW)	Coincident Peak Load Factor	Non Coincident Peak Load Jan-Dec 00:00 to 24:00 (kW)	Overall Coincidence Factor
Residential	453,563	6,757,637,138	14,899	1,516,245	3.34	50.7%	1,700,639	89.2%
GS Small Non Demand	52,467	1,523,468,382	29,037	279,538	5.33	62.0%	323,495	86.4%
GS Small Demand	7,204	1,914,459,806	265,750	330,993	45.95	65.8%	369,848	89.5%
GS Medium SEP	21	23,254,031	1,107,335	6,042	287.73	43.8%	6,653	90.8%
GS Medium	1,907	3,037,152,169	1,592,634	480,429	251.93	72.0%	522,909	91.9%
GS Large 750 V - 30 kV SEP	5	1,913,259	382,652	100	19.98	218.0%	1,361	7.3%
GS Large 750 V - 30 kV	280	1,608,753,312	5,745,548	233,172	832.76	78.5%	255,468	91.3%
GS Large > 100 kV Curtailable	2	1,802,518,540	901,259,270	193,939	96,969.39	105.8%	240,855	80.5%
GS Large > 100 kV	13	2,585,611,024	198,893,156	332,888	25,606.79	88.4%	393,368	84.6%
GS Large 30 - 100 kV Curtailable	1	212,350,227	212,350,227	23,972	23,971.82	100.8%	25,934	92.4%
GS Large 30 - 100 kV	35	946,121,659	27,032,047	115,729	3,306.53	93.1%	158,554	73.0%

Load Research Results Average 2005/2006
Corresponding to Highest 50 Summer Generation Peaks

	Customer Months	Billed Energy	Average Energy	CP Load kW Jun-Aug 06:00 to 22:00	Avg CP Load	CP Load Factor	Summer Energy May-Oct	Summer CP LF
Residential	423,783	6,170,740,484	14,561	611,112	1.44	115.3%	2,373,497,064	88.0%
GS Small Non Demand	50,197	1,320,845,519	26,313	174,929	3.48	86.2%	564,780,628	73.1%
GS Small Demand	9,057	1,924,218,362	212,464	235,512	26.00	93.3%	858,744,381	82.6%
GS Small Demand LUBD	74	6,564,662	88,712	1,470	19.87	51.0%	3,316,551	51.1%
GS Medium	1,754	2,853,801,244	1,627,025	372,163	212.18	87.5%	1,341,964,635	81.7%
GS Medium LUBD	23	6,578,874	285,005	1,474	63.84	51.0%	3,323,732	51.1%
GS Medium SEP	23	20,703,086	920,137	198	8.81	1192.3%	4,446,080	507.9%
GS Large 750-30 kV	233	1,529,944,656	6,554,565	205,458	880.22	85.0%	765,476,808	84.4%
GS Large 750-30 kV LUBD	17	1,378,190	81,070	309	18.16	51.0%	696,279	51.1%
GS Large 750-30 kV SEP	6	2,643,832	440,639	739	123.18	40.8%	1,564,733	47.9%
GS Large 30-100kV	26	555,116,514	21,350,635	58,477	2,249.11	108.4%	255,050,171	98.8%
GS Curtailable 30-100kV	1	220,647,742	220,647,742	25,185	25,184.70	100.0%	110,027,784	98.9%
GS Large 30-100 Total	27	775,764,256	28,468,413	83,661	3,070.14	105.9%	365,077,955	98.8%
GS Large > 100kV	12	2,635,795,910	219,649,659	253,447	21,120.59	118.7%	1,233,471,891	110.2%
GS Large > 100 kV LUBD	1	216,000	216,000	48	48.38	51.0%	109,126	51.1%
GS Curtailable >100kV	3	2,479,408,333	826,469,444	284,088	94,695.90	99.6%	1,233,799,077	98.3%
GS Large > 100kV Total	15	5,115,420,243	341,028,016	537,583	35,838.88	108.6%	2,467,380,094	103.9%

Load Research Results Average 2005/2006
Corresponding to Highest 50 Winter Generation Peaks

	Customer Months	Billed Energy	Average Energy	CP Load kW Dec-Feb 06:00 to 22:00	Avg CP Load	CP Load Factor	Winter Energy Nov-Apr	Winter CP LF
Residential	423,783	6,170,740,484	14,561	1,033,297	2.44	68.2%	3,797,243,420	84.6%
GS Small Non Demand	50,197	1,320,845,519	26,313	240,705	4.80	62.6%	756,064,891	72.3%
GS Small Demand	9,057	1,924,218,362	212,464	301,609	33.30	72.8%	1,065,473,981	81.3%
GS Small Demand LUBD	74	6,564,662	88,712	1,547	20.91	48.4%	3,248,111	48.3%
GS Medium	1,754	2,853,801,244	1,627,025	423,874	241.66	76.9%	1,511,836,609	82.1%
GS Medium LUBD	23	6,578,874	285,005	1,550	67.16	48.4%	3,255,142	48.3%
GS Medium SEP	23	20,703,086	920,137	4,103	182.36	57.6%	16,257,006	91.2%
GS Large 750-30 kV	233	1,529,944,656	6,554,565	217,414	931.44	80.3%	764,467,848	80.9%
GS Large 750-30 kV LUBD	17	1,378,190	81,070	325	19.10	48.4%	681,911	48.3%
GS Large 750-30 kV SEP	6	2,643,832	440,639	413	68.79	73.1%	1,079,099	60.2%
GS Large 30-100kV	26	555,116,514	21,350,635	79,574	3,060.54	79.6%	300,066,343	86.8%
GS Curtailable 30-100kV	1	220,647,742	220,647,742	22,777	22,777.21	110.6%	110,619,957	111.8%
GS Large 30-100 Total	27	775,764,256	28,468,413	102,351	3,756.01	86.5%	410,686,301	92.4%
GS Large > 100kV	12	2,635,795,910	219,649,659	329,160	27,430.03	91.4%	1,402,324,019	98.1%
GS Large > 100 kV LUBD	1	216,000	216,000	51	50.90	48.4%	106,874	48.3%
GS Curtailable >100kV	3	2,479,408,333	826,469,444	289,386	96,462.09	97.8%	1,245,609,256	99.1%
GS Large > 100kV Total	15	5,115,420,243	341,028,016	618,597	41,239.83	94.4%	2,648,040,149	98.5%

Load Research Results Average 2011/2012
Corresponding to Highest 50 Summer Generation and Import Peaks

	Average Annual Metered Customers	Total Energy (kWh)	Average Energy (kWh)	Coincident Peak Load Jun-Aug 06:00 to 22:00 (kW)	Avg Coincident Peak Load (kW)	Coincident Peak Load Factor	Summer Energy May-Oct (kWh)	Summer Coincident Peak Load Factor
Residential	453,563	6,757,637,138	14,899	819,493	1.81	93.9%	2,641,466,491	73.0%
GS Small Non Demand	52,467	1,523,468,382	29,037	214,794	4.09	80.7%	661,306,491	69.7%
GS Small Demand	7,204	1,914,459,806	265,750	248,217	34.46	87.8%	856,983,450	78.2%
GS Medium SEP	21	23,254,031	1,107,335	415	19.77	637.6%	4,591,682	250.4%
GS Medium	1,907	3,037,152,169	1,592,634	428,323	224.61	80.7%	1,452,079,476	76.8%
GS Large 750 V - 30 kV SEP	5	1,913,259	382,652	514	102.79	42.4%	1,237,557	54.5%
GS Large 750 V - 30 kV	280	1,608,753,312	5,745,548	227,789	813.53	80.4%	792,826,892	78.8%
GS Large > 100 kV Curtailable	2	1,802,518,540	901,259,270	190,909	95,454.28	107.5%	879,645,188	104.3%
GS Large > 100 kV	13	2,585,611,024	198,893,156	258,439	19,879.95	113.9%	1,195,509,354	104.8%
GS Large 30 - 100 kV Curtailable	1	212,350,227	212,350,227	25,314	25,313.88	95.5%	107,173,979	95.9%
GS Large 30 - 100 kV	35	946,121,659	27,032,047	94,810	2,708.87	113.6%	442,968,908	105.8%

Load Research Results Average 2011/2012
Corresponding to Highest 50 Winter Generation and Import Peaks

	Average Annual Metered Customers	Total Energy (kWh)	Average Energy (kWh)	Coincident Peak Load Dec-Feb 06:00 to 22:00 (kW)	Avg Coincident Peak Load (kW)	Coincident Peak Load Factor	Winter Energy Nov-Apr (kWh)	Winter Coincident Peak Load Factor
Residential	453,563	6,757,637,138	14,899	1,344,726	2.96	57.2%	4,116,170,647	70.1%
GS Small Non Demand	52,467	1,523,468,382	29,037	267,156	5.09	64.9%	862,161,891	73.9%
GS Small Demand	7,204	1,914,459,806	265,750	314,721	43.69	69.3%	1,057,476,356	76.9%
GS Medium SEP	21	23,254,031	1,107,335	5,420	258.11	48.8%	18,662,349	78.8%
GS Medium	1,907	3,037,152,169	1,592,634	459,542	240.98	75.2%	1,585,072,693	79.0%
GS Large 750 V - 30 kV SEP	5	1,913,259	382,652	102	20.49	212.6%	675,702	151.0%
GS Large 750 V - 30 kV	280	1,608,753,312	5,745,548	228,789	817.10	80.1%	815,926,420	81.6%
GS Large > 100 kV Curtailable	2	1,802,518,540	901,259,270	201,066	100,533.18	102.1%	922,873,352	105.1%
GS Large > 100 kV	13	2,585,611,024	198,893,156	328,575	25,274.97	89.6%	1,390,101,670	96.9%
GS Large 30 - 100 kV Curtailable	1	212,350,227	212,350,227	23,540	23,539.96	102.7%	105,176,248	102.3%
GS Large 30 - 100 kV	35	946,121,659	27,032,047	124,955	3,570.14	86.2%	503,152,751	92.2%

Section:	PCOSS14 MIPUG MFR1	**Page No.:**	pg. 14
Topic:	IFRS - & PCOSS		
Subtopic:	Accounting Implications		
Issue:	IFRS Impact on PCOSS		

PREAMBLE TO IR (IF ANY):

PCOSS 14 does not reflect IFRS. MH has indicated in past filings that it has made changes to its cost allocation to comply with IFRS.

QUESTION:

Please indicate and describe the impact on the PCOSS14 Amended of applying IFRS, indicating which of the financial figures and allocations change materially and for what reason.

RATIONALE FOR QUESTION:

To understand the impact of the current and relevant state of financial reporting on the PCOSS.

RESPONSE:

Manitoba Hydro views that the incorporation of new accounting standards flowing from IFRS should not impact the evaluation of COS methodologies in the current review. The costing changes related to IFRS are in effect timing issues shifting costs between the balance sheet and the income statement and which impact overall revenue requirement. However, IFRS changes are not anticipated to measurably affect class revenue requirement (that is, cost of service). Cost of Service is influenced more greatly by asset cost changes (generation vs transmission for example).

It is likely that the effect of IFRS will require modifications in Cost of Service to adapt to data input changes, however, Manitoba Hydro does not expect the intent of the allocation change. For example, the increase in Operating and Administrative expenses for the 2014/15

fiscal year of approximately $37 million is primarily as a result of overhead costs that are not eligible for capitalization under IFRS. From a Cost of Service perspective, Manitoba Hydro will continue to broadly distribute overhead costs across all functions and sub-functions on the basis of labour cost. The intent of the allocation remains the same, but there may be minor COS impacts if labour costs capitalized vs. expensed are not in the same functional proportions.

Similarly, depreciation expense, an approximate net $53 million decrease in 2014/15 will reduce the cost in each function. For cost of service purposes the intent of the allocation will not change, that is distribution assets, either their investment offset by accumulated depreciation, or the depreciation expense, will continue to be functionalized as distribution. There will be some impact to RCC if the proportions between the functions change. That is, if distribution depreciation expense is reduced to a greater extent than generation or transmission, there will be some impact to each class' allocated costs.

Based on PCOSS14-Amended the changes to RCC as a result of IFRS at this time are expected to be less than +or- 0.5% for most customer classes.

Section:	PCOSS14; MIPUG MFR 4 Attachment	**Page No.:**	pg. 20
Topic:	Net Export Revenue		
Subtopic:	Allocation of Costs to Export Class		
Issue:	Compliance with Order 116/08		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please file a comparative schedule prepared on the same basis as that used in PCOSS14 Amended which compares the $34.4 million in net export revenue per PCOSS14 with the $91 million in net export revenue in PCOSS14 Amended and with a net export revenue tabulation that complies with Order 116/08.

RATIONALE FOR QUESTION:

To understand the impact of each change made to the PCOSS with respect to net export revenues.

RESPONSE:

In PCOSS14-Amended Manitoba Hydro eliminated several direct cost assignments to the export class in favour of a use of two generation pools to simplify cost sharing between domestic and export customers. The differences in allocation approaches are noted below.

	PCOSS14 116/08	PCOSS14	PCOSS14 Amended
	($ Million)	($ Million)	($ Million)
Gross Export Revenue	340*	345	345
Less:			
Purchased Power excl Wind (Note 1)	106	90	25
Purchased Power - Wind (Note 2)	65	10	10
Natural Gas Thermal (Note 2)	17	5	5
Coal Thermal Costs (Note 3)	16	n/a	5
Trading Desk (Note 1)	13	5	4
DSM	40	n/a	n/a
Generation (remaining cost including Hydro, Water Rentals and Variable O&M)	160	132	146
MISO Fees (Note 4)	4	2	1
Transmission	30	29	21
NEB	1	1	1
Policy Related Charges (AER & URA)	36	36	36
Net Export Revenue	(147)	34	91

* Order 116/08 directed Manitoba Hydro to recalculate Gross Export Revenue using the most recent actual export prices. Average export prices in 2012/13 were slightly less than the average forecast price underlying the export revenues for 2013/4, resulting in the $5 million decrease in Gross Export Revenues.

Note 1 – costs were directly assigned to exports in PCOSS14 (Order 116/08) and PCOSS14, and allocated as part of the generation pool in PCOSS14-Amended

Note 2 – costs were directly assigned to exports in PCOSS14 (Order 116/08), and allocated as part of the generation pool in PCOSS14 and PCOSS14-Amended

Note 3 - costs were directly assigned to exports in PCOSS14 (Order 116/08), and allocated as part of the generation pool in PCOSS14-Amended.

Note 4 – costs were directly assigned to exports in PCOSS14 (Order 116/08) and PCOSS14, and allocated on the basis of 2CP Demand in PCOSS14-Amended.

Section:	Appendix 4 Pages 18-25	**Page No.:**	
Topic:	Recommendations from Christensen Associates		
Subtopic:	Impact of Different Changes		
Issue:	Compliance with Board Directives 117/06 & 116/08		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please update the table to include a column beside the recommendation column (to the left) showing the Board-directed treatment for each of the items including Order reference and provide a description of how the directed methodology would impact PCOSS14 Amended.

RATIONALE FOR QUESTION:

To understand the divergence from Board-directed methodology and the impact on PCOSS14 Amended.

RESPONSE:

The following table compares directives included in Orders 117/06 and 116/08 to the corresponding recommendations from Christensen Associates ("CA"), and provides a description of the impact of using Board-directed methodology compared to the treatment in PCOSS14-Amended. Please note that the methodology used in PCOSS14-Amended considered, but is not necessarily the same as, the CA recommendations. Recommendations in Appendix 4 related to Centra Gas or electric issues not specifically addressed in the two Board Orders have not been included in this comparison.

Appendix 4 Number	Orders 117/06 & 116/08	Reference	CA Recommendation	Impact on COS outcomes relative to PCOSS14(Amended)
1	Incorporate exports in the same fashion as other domestic classes	Pg 350 116/08	Maintain Export Class	None. Cost treatment is consistent with treatment in PCOSS14(Amended)
2	One Export Class	Pg 76 117/06	Implement different cost treatments for firm and opportunity sales with firm sales attracting a share of embedded cost and opportunity sales attracting only variable costs.	In PCOSS14-(Amended) dependable exports are allocated a share of embedded Generation and Transmission cost. Impact on results of PCOSS of adoption of this directive: • Negative impact to the RCC's of domestic classes served from the Distribution system (for example: Residential) • Benefit to the RCC's of classes served upstream of the Distribution system (GSL 30 kV and over)
3	AEF (Bill 11) to be assigned against NER.	Pg 76 117/06	AEF costs should either be directly assigned to the class benefitting from the expenditure or excluded from the PCOSS.	None. Cost treatment is consistent with treatment in PCOSS14-Amended.
4	URA to be assigned against NER.	Pg 76 117/06	The cost of the URA should be assigned to the domestic classes which benefit or excluded from COS	None. Cost treatment is consistent with treatment in PCOSS14-Amended.

Appendix 4 Number	Orders 117/06 & 116/08	Reference	CA Recommendation	Impact on COS outcomes relative to PCOSS14(Amended)
5	Purchased power costs are directly attributable to export sales.	Pg 76 117/06	Continue to assign Purchased Power costs as charges against exports, as long as imports remain moderate in size compared to exports.	In PCOSS14-Amended power purchases are allocated between domestic classes and all exports. Impact on results of PCOSS of adoption of this directive: • Negative impact to the RCC's of domestic classes served from the Distribution system (for example: Residential) • Benefit to the RCC's of classes served upstream of the Distribution system (GSL 30 kV and over)
8	Assign 50% fixed and 100% variable thermal plant costs to the Export class	Pg 350 116/08	Allocate coal generation costs to domestic rate classes	In PCOSS14-Amended thermal generation (coal) is allocated between domestic classes and dependable exports. Impact on the results of PCOSS of adoption of this directive: • Negative impact to the RCC's of domestic classes served from the Distribution system (for example: Residential) • Benefit to the RCC's of classes served upstream of the Distribution system (GSL 30 kV and above)

Appendix 4 Number	Orders 117/06 & 116/08	Reference	CA Recommendation	Impact on COS outcomes relative to PCOSS14(Amended)
9	Assign 50% fixed and 100% variable thermal plant costs to the Export class	Pg 350 116/08	Allocate gas-fired thermal plants to domestic and firm exports	In PCOSS14-Amended thermal generation (natural gas) is allocated between domestic classes and dependable exports. Impact on the results of PCOSS of adoption of this directive: • Negative impact to the RCC's of domestic classes served from the Distribution system (for example: Residential) • Benefit to the RCC's of classes served upstream of the Distribution system (GSL 30 kV and above)
10 **11**	Trading desk, MAPP, and MISO costs should be directly assigned to the Export class	Pg 76 117/06	Trading desk costs and MISO and MAPP fees be allocated between exports and domestic classes, and periodically review the allocator	In PCOSS14-Amended trading desk and MISO fees are allocated between domestic classes and all exports. Impact on the results of PCOSS of adoption of this directive: • Negative impact to the RCC's of domestic classes served from the Distribution system (for example: Residential) • Benefit to the RCC of classes served upstream of the Distribution system (GSL 30 kV and above)

Appendix 4 Number	Orders 117/06 & 116/08	Reference	CA Recommendation	Impact on COS outcomes relative to PCOSS14(Amended)
12	Assign DSM cost directly to export class and add DSM energy savings to domestic load for Generation cost-sharing purposes	Pg 350 116/08	DSM program costs should be assigned to the domestic rate class that benefits (via reduced loads and allocations), since this treats DSM costs in a manner identical to any other resource	In PCOSS14-Amended DSM costs are directly assigned to domestic customers participating in the programs. Impact on the results of adoption of this directive: • The impact to domestic customers cannot be generalized but can result in significant and variable changes in RCC. Factors that will determine the class specific impact include the class's cumulative DSM savings compared to forecast consumption and extent that class's DSM programs are fully amortized. Based on PCOSS14-Amended, the residential customers are most negatively impacted. The GSL customers >30 kV benefit to a significant degree. Please see MFR MIPUG 5.
13	Net export revenue is to be allocated to the domestic customer classes, including diesel customers, using the methodology recommended by Manitoba Hydro.	Pg 76 117/06	CA is supportive of the NER treatment that assigns NER on the basis of total cost to serve.	None. Cost treatment is consistent with treatment in PCOSS14-Amended.

Section:	Appendix 5	**Page No.:**	5
Topic:	Net Export Revenue		
Subtopic:	Electricity Export Class		
Issue:	Basis for Investment Decisions		

PREAMBLE TO IR (IF ANY):

Christensen Associates posits two questions concerning MH's intentions with respect to committing to and building resources:

1) Does the Company's long-term projection of the demand for electricity services, used to determine resource requirements, include exports?

2) In essence, does MH commit to physical generation resources to serve domestic loads as well as wholesale markets, or to domestic loads only?

QUESTION:

Please provide MH's responses to the questions posed by Christensen Associates in the preamble.

RATIONALE FOR QUESTION:

To understand the basis for MH's investment decisions.

RESPONSE:

Resource requirements are driven by the need to serve Manitoba load reliably at least cost. Manitoba Hydro's long-term projection and associated investment decision is not based on a strategy or driver to build for export. While export opportunities, imports, and plant advancement are considered in each option evaluated along with other socio-economic and environmental benefits, Manitoba Hydro commits to physical generation resources based on the need to serve Manitoba load.

Please also see Manitoba Hydro's response to PUB/MH-I- 2.

Section:	Appendix 5	**Page No.:**	6
Topic:	Net Export Revenue		
Subtopic:	Export Class		
Issue:	Assignment of Costs to Export Class		

PREAMBLE TO IR (IF ANY):

Christensen Associates states in its 2012 Report:

"MH's preferred cost allocation approach—allocation of net export revenues (NER) to domestic classes after firm export sales have been assigned G&T costs and after opportunity sales have been allocated variable cost—appears to be consistent with the basis upon which MH commits resources, and is also common practice elsewhere."

QUESTION:

a) Please explain what Christensen Associates meant when it indicated that allocation of variable costs to opportunity sales is consistent with the basis upon which MH commits resources.

b) Please describe the practices in other jurisdictions that supports the assertion that the assignment of variable cost to opportunity sales in a COSS is a common practice elsewhere.

c) Please explain how allocating full attributable costs to exports including the costs of the assets required to deliver both firm and opportunity exports in a COSS undermines actual export benefits, given the purpose of the COSS for rate design.

RATIONALE FOR QUESTION:

RESPONSE:

Response from Christensen Associates:

a) Opportunity sales tend to be for short periods of time and occur when water conditions permit this type of export sale. Opportunity sales exists when there is excess energy beyond the needs of Domestic and Dependable energy sales. Opportunity sales are not planned to be backed up by MH resources under low water flow conditions, unlike Dependable sales. When hydro conditions are such that Opportunity sales can take place, the only generation costs that MH incurs are variable costs. Opportunity sales do not affect MH system planning. Therefore, they do not affect MH's commitment of resources. These sales add variable cost only when sales occur, and to allocate variable cost in PCOSS to Opportunity sales only is consistent with the incurrence of their cost.

b) Wholesale sales of non-firm energy (i.e. neither firm nor backed up by system resources) occur for many jurisdictions as a normal activity when capacity permits and sales opportunities exist. These type of "as available" sales are often referred to as Economy sales. They only incur variable generation cost to provide and are sold on the wholesale market if wholesale buyers are willing to pay more than the seller's bid price, which has taken into consideration its variable cost. For example, Georgia Power Company included in its 2013 rate case $21,482,000 of economy sales based on this costing practice.

c) One of the primary purposes of PCOSS is to determine how well Domestic rate classes are covering the cost that they impose on the utility. The study also provides guidance on how rates should be designed to enable cost coverage for each retail class.

   The purpose of Manitoba Hydro (MH) is to provide a safe and reliable supply of electricity to meet the energy needs of the province and to promote economy and efficiency in the supply of that power. As a fortuitous consequence of the geographic conditions in Manitoba, MH's least cost approach to meeting domestic customer needs is to provide hydro-generated electricity as a large portion of its generation. It is economically efficient to construct large-capacity hydro generating stations.

   In the early years following installation, the utility will be long in generation capability, that is, it will have large net supply. This early excess is a feature for many utilities especially with the construction of new base load generation. The temporal abundance in

excess of domestic supply needs can be used to periodically sell energy off-system in a profitable manner.

These off-system Export sales are made into open competitive markets which are often at higher prices than MH's cost of provision. These sales create profits that accrue to the economic benefit of Domestic customers in lowering their cost of electricity from what it might otherwise be and thereby help fulfill MH's business purpose.

The cost of providing these additional Export sales is incremental to MH's mission of serving Domestic customers. These Exports sales' contracts are often of multiple years in duration. Since Export sales are made when MH has sufficient supply available and when the sale price is greater than incremental cost, these sales are profitable and thus benefit Domestic customers. By extension, if such sales were not to take place when available, it would be detrimental to Domestic customers.

However, PCOSS computations are comprised of a one-year view of embedded financial costs and not incremental costs. When these PCOSS embedded costs are allocated and assigned to Export sales, the result is to impute higher cost for Exports than the lower incremental cost actually incurred to provide and enable these Exports sales. These imputed financial costs depicted in PCOSS are not the actual cost of making these Export sales nor do they accurately reveal the real value to Domestic customers. This PCOSS view of Exports, if it were the only consideration, could undermine the perception and understanding of the actual Export benefit: incremental revenues that help to reduce Domestic classes' bills. However, with the eventual allocation of Net Export Revenues back to Domestic rate classes, these net export revenues do not obstruct the purpose of PCOSS in providing cost guidance by class to assist in rate design.

Section:	Attachment 5	**Page No.:**	6
Topic:	Net Export Revenue		
Subtopic:	Export Class		
Issue:	Assignment of Costs to Export Class		

PREAMBLE TO IR (IF ANY):

Christensen Associates states:

"Specifically, firm export sales involve planning with a consideration of the use of and investment in generation and transmission plant; arguably, firm exports should be subject to conventional allocation procedures related to generation and transmission costs in an embedded COS study. Conversely, opportunity sales involve "as available" energy, and do not appear to influence investment in generation and transmission plant and should therefore be accorded only variable cost within cost allocation procedures."

QUESTION:

a) Please explain why Wuskwatim was constructed in advance of domestic need.

b) Please explain why Keeyask is being constructed in advance of domestic need.

c) Please confirm that all business cases where Keeyask G.S. was to be developed included Bipole III's development.

d) Please quantify the extent Bipole III will be used to deliver opportunity export sales from the lower Nelson Generating Stations.

e) Please describe to what extent opportunity sales were incorporated in the NFAT economic analysis to support the investment in Keeyask G.S. and discuss how the results of the NFAT economic analysis would have changed if opportunity exports were excluded.

f) Please indicate what portion of the total forecast export sales (both dollars and volumes)

used in the Keeyask economic analysis relate to opportunity exports. Please provide the details of export sales for the 20 year post in-service of Keeyask.

g) Please indicate what portion of the total forecast export sales (both dollars and volumes) used in the Keeyask economic analysis related to opportunity exports over the full NFAT analysis period.

RATIONALE FOR QUESTION:

RESPONSE:

a) The Wuskwatim project was pursued in advance of the need for new resources to serve Manitoba load ultimately to provide a least cost supply of power to Manitoba Hydro customers over the long term. Advancement provided the opportunity to take advantage of export sales, increase reliability and energy security and reduce the risk of shortfalls due to load uncertainty.

b) The Keeyask project was pursued in advance of the need for new resources to serve Manitoba load ultimately to provide a least cost supply of power to Manitoba Hydro customers over the long term. Advancement of the Keeyask project facilitates higher value export sales and expanded access to the US market through development of a new interconnection which provides reliability benefits to Manitoba customers long into the future beyond the terms of the export sales.

c) To clarify, Bipole III was approved prior to the 2013/14 NFAT process. As such, it was a committed resource included in all development plans presented in the 2013/14 NFAT, including those plans that did not include Keeyask.

d) Manitoba Hydro operates an integrated system in which all available resources are operated as required to meet the total of the Manitoba load and export obligations on a least cost basis while observing operational limitations. Bipole III was designed to ensure a reliable supply of power while meeting peak load requirements, particularly in the case of a loss of Bipole I and/or Bipole II. When firm load is not at its peak and surplus hydro energy is available, the utilization of the HVDC transmission system includes

transmission of energy that can be used to offset the need for thermal generation and imports and/or sold extra-provincially as opportunity sales. As such, the ability to make opportunity sales is a product of the design to meet peak loads reliably and not the primary driver for the required transmission capability of the HVDC system. As discussed in PUB/MH I-28a-b, surplus generation, as well as transmission capability, to make opportunity sales is available at an incremental or variable cost.

e) Opportunity sales were included in the NFAT economic analysis for each development plan presented to reflect expected system operation and Manitoba Hydro's interaction with the opportunity export market. Exclusion of the opportunity exports from the analysis would have reduced the export revenue associated with all development plans presented.

f) The table below provides the average annual split between firm and opportunity export sales for the 20 year post in-service of Keeyask (2020/21 – 2039/40). These results are based on the Keeyask, Gas, and 750 MW Tieline development plan presented during the NFAT. For details related to the firm export sales that are present in this development plan, please see the Manitoba Hydro responses to COALITION-MH I-22a and COALITION-MH I-22b. The development plan used for this response does not include Conawapa, and so the WPS 300 MW contract is not applicable.

	Average Annual Firm Exports	Average Annual Opportunity Exports	Average Annual Total
Energy (GWh @ Generation)	2690	5232	7922
Revenue (Millions of Current CDN Dollars)	241	408	648

The values included in the table indicate total system energy provided to the export market, not export energy available from just Keeyask, nor incremental energy from any potential alternative plan. All development plans will include some level of exports.

The energy available to support average annual firm exports decreases each year as the surplus firm energy is used to meet growing Manitoba Loads, until the surplus decreases to zero. The average system energy in excess of dependable (or the non-firm energy) will remain nearly constant, changing when additional resources are constructed.

g) Total (absolute) export volumes are not available from the extrapolated values which were used in the NFAT extended study period. In the NFAT study, production-costing of various development plans was conducted for a 35-year planning period (2014/15 to 2048/49, inclusive). Benefits of the asset(s) were continued in the post-planning period to represent full-life cycle accounting and in the absence of future plant additions do not represent the total (absolute) projection of export volumes.

Extending the planning period out further than the 20 years requested in part f) of this response, would fully utilize the available dependable energy in meeting Manitoba Load growth, while the non-firm generation not used to offset thermal and import resources, would continue to be available for opportunity export sales.

Section:	Attachment 4;Attachment 5	**Page No.:**	5; 23
Topic:	Exports		
Subtopic:	Net Export Revenue		
Issue:	Assignment of Costs to Export Class		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro typically imports energy rather than employ its thermal generation.

QUESTION:

a) Confirm that in below average flow years imports would displace Manitoba Hydro's thermal generation (which is not competitive in the MISO market).

b) Explain how high volume imports should be treated relative to low levels of opportunity exports.

RATIONALE FOR QUESTION:

To understand the dispatch of MH's non-hydraulic resources.

RESPONSE:

a) Confirmed. Manitoba Hydro dispatches its generating resources in a least cost manner. Generally this means it will be cheaper to purchase energy from the MISO market rather than operate its thermal generation. Only in the worst of droughts when imports are already being maximized does Manitoba Hydro consider it likely that thermal generation will be used. This is not because further imports would not be economic, just that no additional imports would be available due to import limits on the US interconnection or because there are electric reliability reasons requiring generation in Manitoba.

b) As explained in the chart on page 17 of Manitoba Hydro's Cost of Service Methodology Review submission, power purchases support all load under some conditions and therefore Manitoba Hydro's COS assigns them to all load proportionately. Furthermore,

COS is based on median flow conditions where import volumes are lower than opportunity exports.

Section:	Attachment 4 pg 6 Attachment 5 pgs. 24-25	**Page No.:**	
Topic:	Net Export Revenue		
Subtopic:	Costs of Export Class Assignment		
Issue:	Assignment of Thermal and Coal Costs to Export Class		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please describe and quantify the reserve requirements for MH to participate in the MISO market.

b) Please indicate to what extent each of MH's thermal plants - Brandon Unit #5 (coal-fired), Brandon Units #6 and 7, and Selkirk Generating Station - are used to meet these reserve requirements.

RATIONALE FOR QUESTION:

RESPONSE:

a) Manitoba Hydro maintains reserves to serve Manitoba load only. It does not maintain reserves to support export sales.

Consistent with NERC reliability standards which have been adopted as reliability standards in Manitoba pursuant to *The Manitoba Hydro Act (C.C.S.M. c. H190)*, Reliability Standards Regulation 25/2012, Manitoba Hydro is required to maintain operating reserves to reliably operate its generation and transmission system. This is regardless of whether it participates in the MISO market.

Two types of operating reserves are Regulation Reserves and Contingency Reserves. In order to balance supply and demand on a minute-to-minute basis Manitoba Hydro carries regulation reserves which are automatically controlled generation. Currently Manitoba Hydro reserves 50 MW of generation to provide this function.

Contingency reserves are also required to maintain reliable operations. Manitoba Hydro is required to have access to contingency reserves to cover for a sudden loss of its single largest contingency. For the Manitoba Hydro system alone, this contingency is a 1000 MWs (the loss of a single pole on HVDC bipole 2).

To meet this requirement at least cost to Manitoba Hydro and recognizing the mutual benefits that could be achieved, Manitoba Hydro and MISO formed the MISO-MB Hydro Contingency Reserve Sharing Group (CRSG) to provide 2000 MW of contingency reserves. The agreement governing the MISO-MB Hydro CRSG was filed by MISO with the Federal Energy Regulatory Commission (FERC) on October 19, 2009 (http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12178436).

Under this agreement, Manitoba Hydro's contingency reserve obligation is 150 MW and MISO's obligation is 1,850 MW. This agreement provides value to the combined system by freeing up generation capacity for commercial use. For Manitoba Hydro, this means more hydro capacity can be used for generation as opposed to being held on stand-by to respond to a sudden loss of supply.

In the absence of interconnections and Manitoba Hydro's export market participation, sharing contingency reserves with neighbouring systems (in Canada or the US) would not be possible and Manitoba Hydro would have to carry significantly more contingency reserves on its own. Interconnections and active participation in MISO has had the effect of significantly reducing Manitoba Hydro's operating reserve requirements.

b) Manitoba Hydro's thermal units are not on automatic control and therefore are not capable of providing regulation reserves.

Manitoba Hydro's combustion turbines are rarely used to provide contingency reserves. Generally they would have to be online already to be able to respond to a loss on the system. And as they are very expensive to operate relative to other alternatives when

start-up costs are considered, they do not operate much more than for testing and proficiency runs.

The generation ramping capabilities of Brandon Unit 5 and the Selkirk steam turbines are too slow for use as contingency reserves. Furthermore, Brandon Unit 5 operations are restricted by *The Climate Change and Emissions Reductions Act* (C.C.S.M. c. C135) to support emergency conditions. Therefore, these steam units could only provide a portion of Manitoba Hydro's contingency reserves when they are on-line, which is also relatively infrequent.

Brandon combustion turbines are quicker responding and could provide additional contingency reserve service. However, for them to supply reserves they must be on-line already.

Curtailable Rate Program Option 'R' load is used to provide 50 MW of MH's 150 MW contingency reserve obligation and most of the time there is sufficient capacity available on hydro-electric units to provide the remaining 100 MW.

Section:	Attachment 4 pg 6 Attachment 5 pgs. 24-25	**Page No.:**	
Topic:	Net Export Revenue		
Subtopic:	Costs of Export Class Assignment		
Issue:	Assignment of Thermal and Coal Costs to Export Class		

PREAMBLE TO IR (IF ANY):

QUESTION:

c) In light of the answer to (b), explain why the assignment of 50% of thermal fixed costs and 100% of the variable costs for thermal units is considered by MH as unfairly burdensome in the context of a COS allocation to exports.

RATIONALE FOR QUESTION:

RESPONSE:

As discussed in parts a) and b), Manitoba Hydro does not maintain reserves for exports and it would therefore be inappropriate to justify assigning any thermal generation costs to exports on this basis.

Please also see Manitoba Hydro's response to PUB/MH I-2.

Section:	Attachment 4 pg 6 Attachment 5 pgs. 24-25	**Page No.:**	
Topic:	Net Export Revenue		
Subtopic:	Costs of Export Class Assignment		
Issue:	Assignment of Thermal and Coal Costs to Export Class		

PREAMBLE TO IR (IF ANY):

QUESTION:

d) Please confirm whether MH is able to increase its contracted export volumes compared to a situation where MH did not have thermal generation.

RATIONALE FOR QUESTION:

RESPONSE:

Not confirmed. Manitoba Hydro's thermal generation is of limited value to increasing Manitoba Hydro's export volumes.

Most recent export contracts have been tied to new dependable surpluses created from the construction of new hydraulic facilities and not the existing surpluses available from Manitoba Hydro's heritage resources.

The effect of having additional dependable energy from thermal resources is mainly on the timing of new resources to serve Manitoba load, not on additional export sales.

Section:	Attachment 4 pg 6 Attachment 5 pgs. 24-25	**Page No.:**	
Topic:	Net Export Revenue		
Subtopic:	Costs of Export Class Assignment		
Issue:	Assignment of Thermal and Coal Costs to Export Class		

PREAMBLE TO IR (IF ANY):

QUESTION:

e) Please confirm whether, in average and above average water flow years, MH is able to serve the increased contracted (firm) export volumes in (d) with hydraulic generation.

RATIONALE FOR QUESTION:

RESPONSE:

As indicated in part d) most recent export sales are the result of Manitoba Hydro's commitment to build new hydraulic generation that provides sufficient new dependable hydraulic energy. As such increased export sales will be supplied by new hydraulic generation under all flow conditions.

Section:	Attachment 4 pg 6 Attachment 5 pgs. 24-25	**Page No.:**	
Topic:	Net Export Revenue		
Subtopic:	Costs of Export Class Assignment		
Issue:	Assignment of Thermal and Coal Costs to Export Class		

PREAMBLE TO IR (IF ANY):

QUESTION:

f) Please provide a comparison of the actual costs allocated for coal and natural gas generation under Christensen's proposed approach and that directed by the Board in Orders 117/06 and 116/08.

RATIONALE FOR QUESTION:

RESPONSE:

Under the approach from Order 117/06 and 116/08, exports are assigned all thermal fuel costs and 50 percent of the balance of thermal generation costs for a total of $33 million. The remaining $28 million of costs are allocated to domestic classes.

Christensen's proposed approach for thermal generation is consistent with the approach used in PCOSS14, with costs of natural gas generation shared by domestic and dependable exports, and coal generation costs allocated to domestic customers only. Under this approach $5 million of thermal generation costs are allocated to exports and the remaining $56 million to domestic customers.

Manitoba Hydro has adopted a pooled approach in PCOSS14 Amended that allocates thermal generation between domestic and dependable export sales. Under the approach domestic customers are responsible for $51 million of thermal generation, and exports $10 million.

Section:	PCOSS14 pg 11, MIPUG MFR9 Appendix 5 pg. 24-25	**Page No.:**	
Topic:	Net Export Revenue		
Subtopic:	Trading Desk – MISO Cost Assignment		
Issue:	Assignment of Costs to Export Class		

PREAMBLE TO IR (IF ANY):

In PCOSS 14 MH states that:

"The 'Trading Desk', as well as MISO membership provides benefits to domestic customers by facilitating import purchases needed for dependable supply, and during periods of prolonged drought, or in the event of a major generation or transmission failure. Consequently, the portion of these costs that can be directly attributed to Manitoba Hydro's export sales activities has been directly assigned to the export class. The remaining 58% of the costs have been assigned to the domestic classes."

QUESTION:

a) Please file a detailed schedule of Trading Desk costs and MISO fees which are allocated in the PCOSS.

b) Please provide a detailed explanation as to how MH determined that 42% of the trading desk and MISO Fees relate to export sales and 58% to the domestic class.

c) Please explain why MH has not allocated 100% of the trading desk costs to the export class as directed in Order 116/08.

d) Please explain why MH has not allocated 100% of the MISO fees to the export class as directed in Order 116/08.

e) Please file an update to the response to MIPUG/MH I-22 from the 2010/11 & 2011/12 GRA.

f) Please file any analysis that supports the percentage allocation of trading desk between exports and domestic with a detailed explanation supporting the determination.

g) Please explain why MISO fees are allocated on the same basis as trading desk activity and not on the basis of actual energy usage.

RATIONALE FOR QUESTION:

RESPONSE:

Response to parts a) to g):

The use of 'Trading Desk' in the COSS refers to the cost of the line areas within the Power Sales & Operations Division that support export sales activities. This includes not only traders, but also staff involved in negotiating future sales as well as other technical personal that primarily support the export function. The specific departments included are:

- Export Operations Department
- Export Billing Department
- Export Power Marketing Department
- Market Process & Technology Department

Manitoba Hydro does not view the costs as entirely export related as in the absence of exports, staff would continue to be required to maintain the required import abilities, including supporting the ability to secure power that may be needed to support domestic load during drought or system emergency. In 2009, the organization charts for the departments noted above were reviewed to determine which EFTs would hypothetically not exist if Manitoba Hydro did not export. The exercise indicated that 25 of the 60 EFTs could be viewed as export related, resulting in the 42% export related and 58% domestic customer related shares used in COS. Manitoba Hydro has not undertaken an update of the analysis since the 2009 analysis described in MIPUG/MH-22(c) from the 2010/11 & 2011/12 GRA.

MISO fees referenced represent membership and legal fees necessary to maintain access to the MISO market. This access is required for domestic reliability purposes and would be required even in absence of export sales.

In PCOSS14-Amended Manitoba Hydro has simplified the approach and used weighted energy to allocate 'Trading Desk' and MISO fees between domestic and export load, consistent with allocation of other Generation costs. Due to the low quantum of costs involved, the impact on class RCCs is not material, with a difference in the order of +/- 0.1% between the approaches used in PCOSS14 versus PCOSS14-Amended.

Section:	PUB MFR 13	**Page No.:**	
Topic:	Methodological Changes		
Subtopic:	Progression of Revenue Cost Coverage (RCC) Ratios		
Issue:	Compliance with Order 116/08		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide a table showing the RCCs by customer class and subclass for each PCOSS shown in PUB MFR 13 as well as for each PCOSS back to 2003/04.

b) In the tabular progression of PCOSS changes shown in PUB MFR 13, for PCOSS10, PCOSS13, PCOSS14, and PCOSS14 Amended, please indicate each methodology change that varied from that directed in Order 116/08 with a detailed explanation of the rationale for each change.

RATIONALE FOR QUESTION:

To understand the changes to the cost allocation methodology and the impact on the rate classes allocation of costs.

RESPONSE:

a)

	PCOSS04 January 2004	PCOSS06 Recommended	PCOSS06 Response to 117/06	PCOSS08 Response to 116/08	PCOSS10 Nov 30, 2009	PCOSS13 With Methodology Changes July 2012	PCOSS14 June 2013	PCOSS14-Amended December 2015
Res	90.6%	97.0%	94.1%	96.2%	96.4%	99.2%	98.6%	99.8%
GSS ND	104.9%	107.4%	107.4%	101.4%	105.7%	107.6%	107.7%	108.0%
GSS D	109.7%	105.4%	106.9%	107.8%	102.8%	103.7%	104.9%	104.5%
GSM	104.8%	100.6%	101.4%	100.2%	101.3%	100.0%	100.0%	99.4%
GSL 0-30	99.9%	90.1%	91.3%	89.9%	92.3%	93.3%	91.9%	91.3%
GSL 30-100	109.5%	101.5%	104.7%	108.4%	106.8%	96.6%	101.7%	100.0%
GSL >100	114.2%	103.2%	110.0%	112.0%	109.2%	100.5%	101.0%	98.6%
ARL	108.9%	107.1%	107.7%	102.4%	100.0%	101.8%	99.7%	100.2%

The RCC changes provided in the table above result from both changes in the IFF, loads (actual and forecast) as well as COS methodology.

b) Please refer to MIPUG MFR 6 for a comparison of methodologies used and supporting rationale for PCOSS14-Amended and the directives in Order 116/08. The changes undertaken in each successive version of the PCOSS were determined by Manitoba Hydro to better represent the appropriate assessment of customer class cost responsibilities.

Section:	Attachment 5	**Page No.:**	26 - 27
Topic:	Net Export Revenue		
Subtopic:	Assignment of Costs to Export Class		
Issue:	Assignment of DSM Costs to Export Class		

PREAMBLE TO IR (IF ANY):

MH has stated in past responses that:

"Manitoba Hydro interprets marginal cost to mean the cost or value to the system of an incremental quantity of energy and/or capacity. The marginal cost includes a generation component as well as transmission and distribution components as applicable.

The current methodology for determining the generation component of marginal cost is based on the value to the Manitoba Hydro system of an increment of energy and capacity under a range of water flow conditions. This methodology is based on the premise that Manitoba Hydro may be able to create additional export sales from the energy and capacity associated with a reduction in domestic load." [CAC-GAC/MH I-5, 2012/13 & 2013/14 GRA]

The marginal cost is used to evaluate new and existing DSM initiatives.

MH has indicated:

"The levelized marginal value used for the analysis in the 2011 Power Smart Plan is 8.52 cents per kW.h (at meter). The marginal cost contains the expected value of electricity exports which is commercially sensitive." [PUBMH I-107, 2012/13 & 2013/14 GRA]

QUESTION:

a) Please indicate the marginal cost and its derivation that MH is currently using to evaluate new and existing DSM initiatives.

b) In light of the screening done for establishing DSM programs, which is based on marginal cost based primarily on export prices, please explain the inherent

contradiction with Christensen Associates' position that DSM is not driven by Export Sales.

RATIONALE FOR QUESTION:

RESPONSE:

a) In terms of providing clarification, Manitoba Hydro notes that the citation in the preamble is CAC-GAC/MH I-4.

Manitoba Hydro utilizes long-run marginal cost for the evaluation of DSM initiatives. The levelized marginal value used for the analysis in the 2015 Power Smart Plan is 7.67 cents per kWh (at meter) and supersedes the values provided in 2012/13 & 2013/14 Electric General Rate Application Information Request PUB/MH I-107.

The marginal cost contains the expected value of electricity exports which is commercially sensitive. Therefore, detailed information on the derivation of the marginal cost cannot be provided.

b) Response provided by Christensen Associates:

PCOSS is comprised of embedded financial cost. These costs have to be assigned or allocated to the respective customer groups. The PCOSS methodology, as well as the industry standard, to accomplish this division into customer groups is based upon cost causation, not product value. DSM program costs are incurred for specific customer groups in order to enable the customers within these groups to become more efficient and benefit from lower energy bills than they would otherwise incur. It is true that if DSM results in "freed-up" energy which can be sold on the Export market above cost that there will be value for the MH system. (This is why the DSM programs are screened accordingly.) However, costs are allocated based upon cost causation, not value. CA Energy Consulting's position is not that Export sales cannot influence the value to the MH system of DSM, but simply that DSM costs should be allocated in PCOSS to the Domestic rate groups which cause each program's costs.

Section:	Attachment 5	**Page No.:**	26 - 27
Topic:	Net Export Revenue		
Subtopic:	Assignment of Costs to Export Class		
Issue:	Assignment of DSM Costs to Export Class		

PREAMBLE TO IR (IF ANY):

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The current methodology for determining the generation component of marginal cost is based on the value to the Manitoba Hydro system of an increment of energy and capacity under a range of water flow conditions. This methodology is based on the premise that Manitoba Hydro may be able to create additional export sales from the energy and capacity associated with a reduction in domestic load." [CAC-GAC/MH I-5, 2012/13 & 2013/14 GRA]

The marginal cost is used to evaluate new and existing DSM initiatives.

MH has indicated:

"The levelized marginal value used for the analysis in the 2011 Power Smart Plan is 8.52 cents per kW.h (at meter). The marginal cost contains the expected value of electricity exports which is commercially sensitive." [PUBMH I-107, 2012/13 & 2013/14 GRA]

QUESTION:

c) Please file a 10 year forecast of export sales (volumes and revenues), fuel and power purchases, and net export revenue assuming no further DSM program spending or associated DSM savings.

d) Please file the IFF12 forecast of export sales for 2013/14 (volumes and revenues), fuel

and power purchases, and net export revenue assuming no DSM program spending or associated DSM savings have been incurred to date or will be incurred.

RATIONALE FOR QUESTION:

RESPONSE:

c) This Information Request discloses information on forecast export volumes and revenues from which detailed marginal cost/export price forecast information can be inferred. This information is commercially sensitive and confidential. Therefore, the response is being filed in confidence under Rule 13 of the Public Utilities Board's Rules of Practice and Procedure.

d) Manitoba Hydro does not have a financial model to produce the requested hypothetical scenario.

The information requested is a hypothetical historical scenario which would require Manitoba Hydro to unwind past DSM activities as well as all generation and some transmission and distribution investment decisions since 1988/89, to speculate on what different generation, transmission and distribution investment decisions would have been made in the last 25 years, and to recast the 2013/14 results based on IFF12 forecast assumptions.Manitoba Hydro would have to make numerous major hypothetical assumptions to determine what generation, transmission and distribution investment would have been made over the last 25 years in light of the higher load growth due to the lack of DSM. The lack of DSM would result in a higher load today, greater and/or earlier investment commitments, as well as different debt profile, carrying and operating costs and different domestic and export revenues.

Section:	PCOSS14 Amended	**Page No.:**	
Topic:	Transmission and Distribution Marginal Cost		
Subtopic:			
Issue:	Marginal Cost		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide MH's current estimates of marginal T&D costs.

b) Please provide the Company's most recent marginal T&D cost study, including all work papers and electronic spreadsheets (with formulas intact).

c) Please provide the source of MH's current estimates of marginal T&D costs, including studies, working papers, and Excel spreadsheets (with formulas intact), if different from the response to (b).

RATIONALE FOR QUESTION:

To understand changes in marginal cost.

RESPONSE:

a) Manitoba Hydro's 2009 long term marginal T&D costs are as follows:

<u>2009 T&D Marginal Costs (2009 dollars)</u>

Transmission:	$51.20 / (kW.Year)
Distribution:	$61.05 / (kW.Year)
Total T&D:	$112.25 / (kW.Year)

Response to part b) and c)

As per confirmation from PUB counsel on April 12, 2016, no marginal T&D cost studies, working papers, or electronic spreadsheets are required to be filed. For Manitoba Hydro's estimate of marginal cost, please see Manitoba Hydro's response to part a).

Section:	Appendix 5 CA Report	**Page No.:**	pg. 10
Topic:	Net Export Revenue		
Subtopic:			
Issue:	Allocation of Net Export Revenue to Customer Classes		

PREAMBLE TO IR (IF ANY):

Christensen Associates provided alternatives to the allocation of net export revenue to customer classes.

QUESTION:

a) Please provide a table indicating the pros and cons of each of the alternative methods Christensen Associates mentioned for the allocation of Net Export Revenue based on principles of fairness.

b) Please provide a full description of each approach and explain with an illustrative example of how each would be calculated and result in an allocation of Net Export Revenue.

c) Please describe the allocators that recognized the differential risk absorbed by customer classes as Net Export Revenue oscillates over time.

d) Please indicate what if any of the above allocators would be more appropriate if the net export revenue were negative as in the case of complying with Order 116/08. Please discuss.

e) Please file any analysis MH has prepared on each of the alternate approaches in (a).

f) Please provide a full description of the alternative approaches that do not distort price signals. Please provide a full description of the approach followed by BC Hydro and how such an approach could be implemented in Manitoba.

g) Please provide a comparison of the allocated NER by customer class based on

proportionate Generation & Transmission costs.

h) Please provide a comparison of the allocated NER by customer class based on an energy available for export/ unused capacity approach.

RATIONALE FOR QUESTION:

To assess merits of alternative allocation of net export revenue.

RESPONSE:

a) The 2004 NERA Report tested three methods of allocating net export revenues, including: on the basis of total allocated costs (GT&D), on the basis of allocated G&T costs, and on the basis of annual energy consumption. NERA concluded net revenues should be allocated in a minimally distorting way that fairly shares the benefits of the Province's hydro resources, and recommended that an allocation in proportion to total allocated costs achieved these goals. Manitoba Hydro adopted this recommendation, and continues to allocate net export revenue on the basis of total cost to serve.

In their 2012 review, Christensen Associates supported the current allocation of NER and recommended that Manitoba Hydro investigate other allocators including: existing allocators such as those used for G&T, allocators that recognize differential risk born by classes as NER changes over time, and allocators based on unused capacity by each rate class which would be available for export. As Manitoba Hydro stated in its Submission (Appendix 4, page 7), it found the unused capacity (energy available for export) approach sufficiently interesting to merit further consideration.

Upon conclusion of the COS review in 2012, Manitoba Hydro investigated the alternative further. Manitoba Hydro raised this alternative at the Stakeholder Workshop in the fall of 2014 to gauge the degree of Stakeholder interest about the concept. The approach recognizes export sales are not correctly attributable to domestic customer's use of the resources but rather attributable to the surplus capability of those resources. Kansas City Power and Light (KCPL) used the energy available for export method. Under this approach the assignment of capacity costs to individual classes in the cost of service study suggests an implicit class entitlement and right to the underlying capacity, as well as the energy that can be produced by it. For each class, the difference between the class'

energy entitlement and their actual consumption represents the class' contribution to energy available for export. The relative share of the total energy available for export is then used by KCPL to allocate non-firm off system sales.

The entitlement to the unused energy is entirely premised on the assignment of generation facilities to classes on a capacity basis, and is inconsistent with Manitoba Hydro's allocation of generation on the basis of marginal weighted energy. The implementation would require a significant change in the way Manitoba Hydro treats generation costs, changing classification from entirely weighted energy to entirely demand related. The overall impact of the methodology appeared to be influenced much greater from the change in classification of generation costs than from the change in NER allocation. Other complications to operationalize the methodology also occurred. Manitoba Hydro concluded that it was not compatible with its largely hydraulic system. It also understood that it was controversial for KCPL, the only utility to have implemented the approach.

b) Subject to the caveats discussed in part a), the following example illustrates how the calculation of the unused energy approach could be used to determine class NER share's based on PCOSS14.

PCOSS14 Load Data Used in Calculation:

A	Energy Including All Exports (MWh)	35,189,701
B	Winter Peak including All Exports (MW)	4,946
C	System Load Factor (SLF)	81.2%

Calculation of Unused Energy by Class:

	D	E	F	G	H	I
	Winter Peak MW	Grossed-up Winter Peak MW	Energy Entitlement MWh	Annual Energy MWh	Unused Energy MWh	Share of Unused Energy
	Schedule D1	B x (Class D/Total D)	C x E x 8760	Schedule D1	F – G	Class H/ Total H
Residential	1,775	2,095	14,902,525	8,659,591	6,242,934	64.1%
GSS ND	335	395	2,810,129	1,865,834	944,296	9.7%
GSS D	397	469	3,333,410	2,363,969	969,441	10.0%
GSM	564	666	4,737,958	3,653,690	1,084,268	11.1%
GSL 0-30kV	277	327	2,328,369	1,942,588	385,781	4.0%
GSL 30-100 kV	187	221	1,573,663	1,475,486	98,177	1.0%
GSL > 100 kV	638	752	5,352,812	5,371,023	(18,211)	-0.2%
A&RL	18	21	150,835	117,521	33,315	0.3%
Total	4,191	4,946	35,189,701	25,449,701	9,740,000	100.0%

c) Manitoba Hydro has not pursued this option given its complexity. The allocation of NER on the basis of total cost to serve, however, does reduce the impact of oscillations in export revenues over time. The approach aligns the method of allocating the 'costs' of exports to domestic classes (i.e. additional net income broadly allocated on rate base) with the method of returning the net benefit of exports to domestic classes (i.e. broadly allocated on total cost to serve). Allocating the costs and benefits of exports in similar proportions dampens RCC volatility due to large changes in export revenue.

d) Under a well-founded cost allocation methodology, there should be no negative export revenue. Cost of Service is forward looking based on median conditions and weather normalized loads. Once a capital plan is approved, there is a presumption that over the long-run, customers are better off than they would have been under any alternate plan that excluded exports. The logical corollary of that is, in the long term, to the extent that costs of the approved plan may exceed the costs of the alternate plan, that excess will be more than covered by export revenues. If there are any negative export revenues in a PCOSS, they should be viewed as the result of either timing issues between recognition of new facility costs and associated export revenues, or more likely, as the result of selecting an inappropriate method of assigning costs to an export class.

COS is intended to reflect average conditions and should reflect the long term situation in which there are real net export revenues. Therefore, even if you adopt an extreme

position on cost responsibility for opportunity sales, that cost responsibility should never be allowed to exceed the value of Export revenue in the COSS.

Regardless of the approach used with respect to the determination of NER, Manitoba Hydro is of the view that URA and AEF are policy initiatives that Manitoba Hydro has been directed to fund at no direct cost to the affected classes. These initiatives are not a cost of exports, but represent a policy related charge against export revenues that could be treated differently if net export revenue is insufficient to fund them. One possibility is to include them with net income in the Revenue Requirement, which would spread the costs broadly among all domestic classes in similar proportions to the current allocation on total cost to serve.

Finally, it is useful to highlight that, regardless of the method chosen to allocate costs against exports, or the method chosen to allocate net export revenue credits against the costs allocated among the domestic classes of service, the same total revenue must be obtained from domestic classes collectively. The approaches taken to estimate the cost of export sales and the allocation of net export credits only affect the percentage of total Revenue Requirement that must be obtained from each class of service.

e) Please see page 18 of Manitoba Hydro's December 4, 2015 Submission.

f) Christensen Associates identified two additional approaches to NER that did not distort downward an already low price signal:
   - Lump sum bill credits, not tied to customer energy use;
   - Assignment of NER to a fund to support future construction or debt buy-back, with rules about transfers in and out of the fund to benefit customers or government.

   Both of these approaches are significant departures from approaches traditionally used and accepted by Manitoba Hydro, the PUB and other stakeholders. Furthermore, the method proposed by Manitoba Hydro is an approach intended to moderate distortion in price signals. As such, Manitoba Hydro has not explored either above alternative any further.

   While Manitoba Hydro understands that the transfer of export revenue between Powerex and BC Hydro is capped, Manitoba Hydro does not have sufficient further knowledge of the cost sharing between the utility and its subsidiary or the other relevant provincial

institutional framework to conclude whether such an approach in that jurisdiction could be implemented in Manitoba.

g) The following compares the allocation of net export revenue from PCOSS14-Amended on the basis of total cost with an allocation on allocated Generation and Transmission costs only. The relative shares of NER by class are also provided based on the energy available for export approach.

	NER on Total Allocated Costs		**NER on G&T Costs**		**NER on Energy Available for Export***
	($ 000's)	**% Share**	**($ 000's)**	**% Share**	**% Share**
Residential	39,179	43.0%	32,113	35.2%	64.1%
GSS Non Demand	8,017	8.8%	6,950	7.6%	9.7%
GSS Demand	8,352	9.2%	8,629	9.5%	10.0%
GSM	12,190	13.4%	13,269	14.6%	11.1%
GSL 0-30 kV	6,058	6.6%	6,978	7.7%	4.0%
GSL 30-100 kV	3,807	4.2%	4,956	5.4%	1.0%
GSL >100 kV	12,514	13.7%	17,958	19.7%	-0.2%
A&RL	419	0.5%	310	0.3%	0.3%
Diesel	626	0.7%	n/a	n/a	n/a
Total NER	91,163	100.0%	91,163	100.0%	100.0%

* Exports are assigned variable costs only under energy available for export approach

h) Please see the response to part g) above.

Section:	PCOSS14 Amended	**Page No.:**	Cost of Service Study
Topic:	Detailed Allocation Schedules		
Subtopic:	PCOSS14 Amended		
Issue:			

PREAMBLE TO IR (IF ANY):

QUESTION:

Please file a complete version of PCOSS14 Amended with all related rate schedules including the allocation program.

RATIONALE FOR QUESTION:

PCOSS14 Amended is not a complete filing.

RESPONSE:

A complete version of PCOSS14-Amended including the Allocation Program was filed March 11, 2016 and can be found on Manitoba Hydro's File Transfer Site under the folder named "Additional Data March 11 2016".

Section:	2014/15 Load Forecast	**Page No.:**	Table 30
Topic:	Domestic & Export Energy Sales		
Subtopic:	Domestic & Export Energy Profiles 2014/15		
Issue:	Incremental Impacts of Exports on Cost Sharing		

PREAMBLE TO IR (IF ANY):

MH's domestic profile has evolved since the 2008/09 economic downturn.

QUESTION:

a) Provide a graphical illustration of MH's actual 2014/15 average monthly energy (GWh) consumption, separately depicting the 7x16 sales and the 7x8 night-time sales.

b) Provide the data for the graph in (a) in both table and electronic form.

c) Provide a revised graph (a) to include transmission losses (I2R) for each 2014/15 month, separately showing 7 x 16 and 7 x 8 sales (assuming zero exports).

d) Provide the data for the graph in (c) in both table and electronic form.

e) Provide another version of graph (c) but include export sales and incremental transmission losses (I2R) for each month separately showing 7 x 16 and 7 x 8 sales including exports.

f) Provide the data for the graph in (e) in both table and electronic form.

RATIONALE FOR QUESTION:

Updated load profile required to support cost allocations.

RESPONSE:

Loss calculations have been prepared using the method described in Needs For and Alternatives To (NFAT) submission MH Exhibit #176-1[1], where it is stated that:

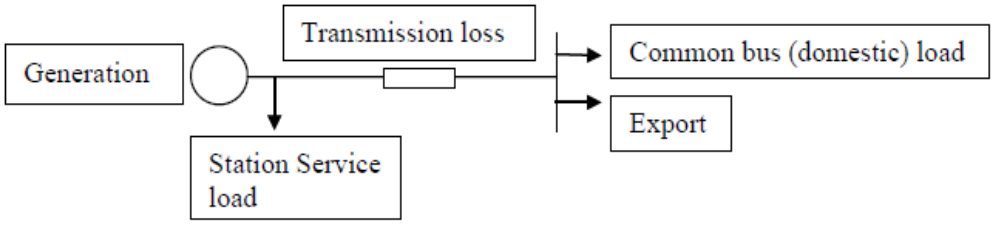
> *The accurate calculation and tracking of system losses and allocation to various load classes including exports is a complex engineering calculation. For this reason Manitoba Hydro has adopted a method for accounting purposes which determines total losses required to supply total load and assigns the same hourly loss/gain ratio to all load classes (residential, commercial, industrial, exports and imports).*
>
> *With the exception of load flow studies based on actual hourly system data, Manitoba Hydro does not endorse other incremental loss accounting methodologies including the one requested in this Undertaking. These other methodologies have no technical justification for being more accurate or appropriate than the Manitoba Hydro average loss accounting method as they ignore:*
>
> *a) That exports and imports can be scheduled simultaneously at any time during the day,*
> *b) That all Manitoba Hydro generators can be the source of exports or can be reduced by imports,*
> *c) That the marginal MW of load being served by Manitoba generation is not always an export MW,*
> *d) That Manitoba Hydro is not the only entity using its transmission system to export or import from Manitoba as access to Manitoba Hydro's transmission system is available to all as provided under the MH Transmission Tariff,*
> *e) That loop flows from the US increase losses in Manitoba and are beyond Manitoba Hydro's control. Loop flows are routine and aren't the result of Manitoba Hydro exports activities. …*
> *f) That a portion of the Manitoba load is served on an interruptible basis equivalent to exports.*

[1] See http://www.pub.gov.mb.ca/nfat_hearing/NFAT%20Exhibits/MH-176-1.pdf

And also,

However as requested in the Undertaking Manitoba Hydro has calculated incremental losses below using the alternative methodology requested although as explained above it is no more accurate than the Manitoba Hydro practice.

A simple representation of losses in Manitoba can be shown by the following diagram.



Assuming transmission loss is represented by an equivalent resistance (R), then $I_{cb}^2R=Loss_{cb}$*. Transmission losses associated with supplying the common bus load is* ($Loss_{cb}$)*. Similar formulas can be derived for transmission losses associated with exports* ($Loss_{export}$) *and total losses* ($Loss_{total}$)*.*

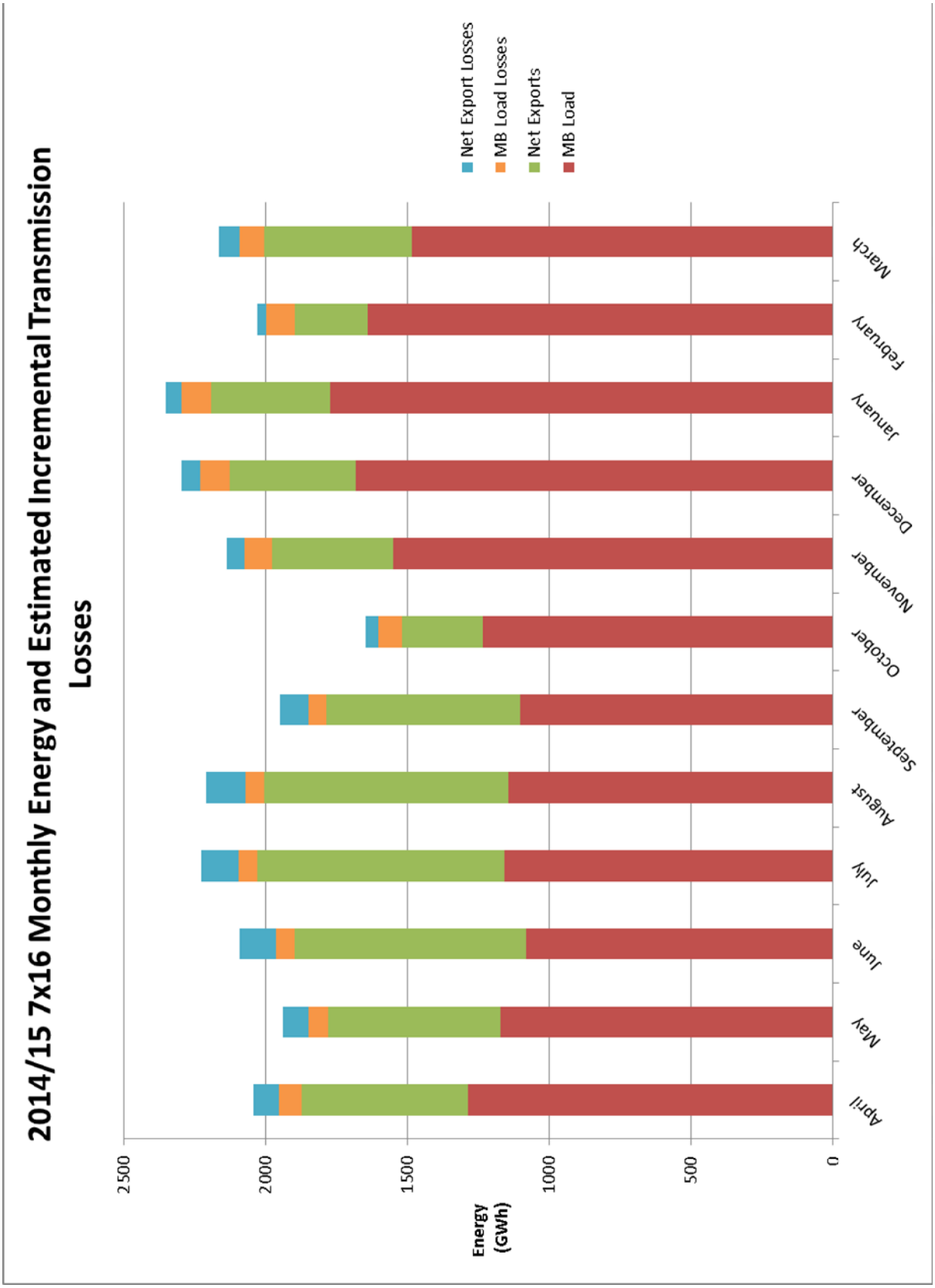
$$I_{cb}^2R=Loss_{cb}$$
$$(I_{cb} + I_{export})^2R=Loss_{total}$$

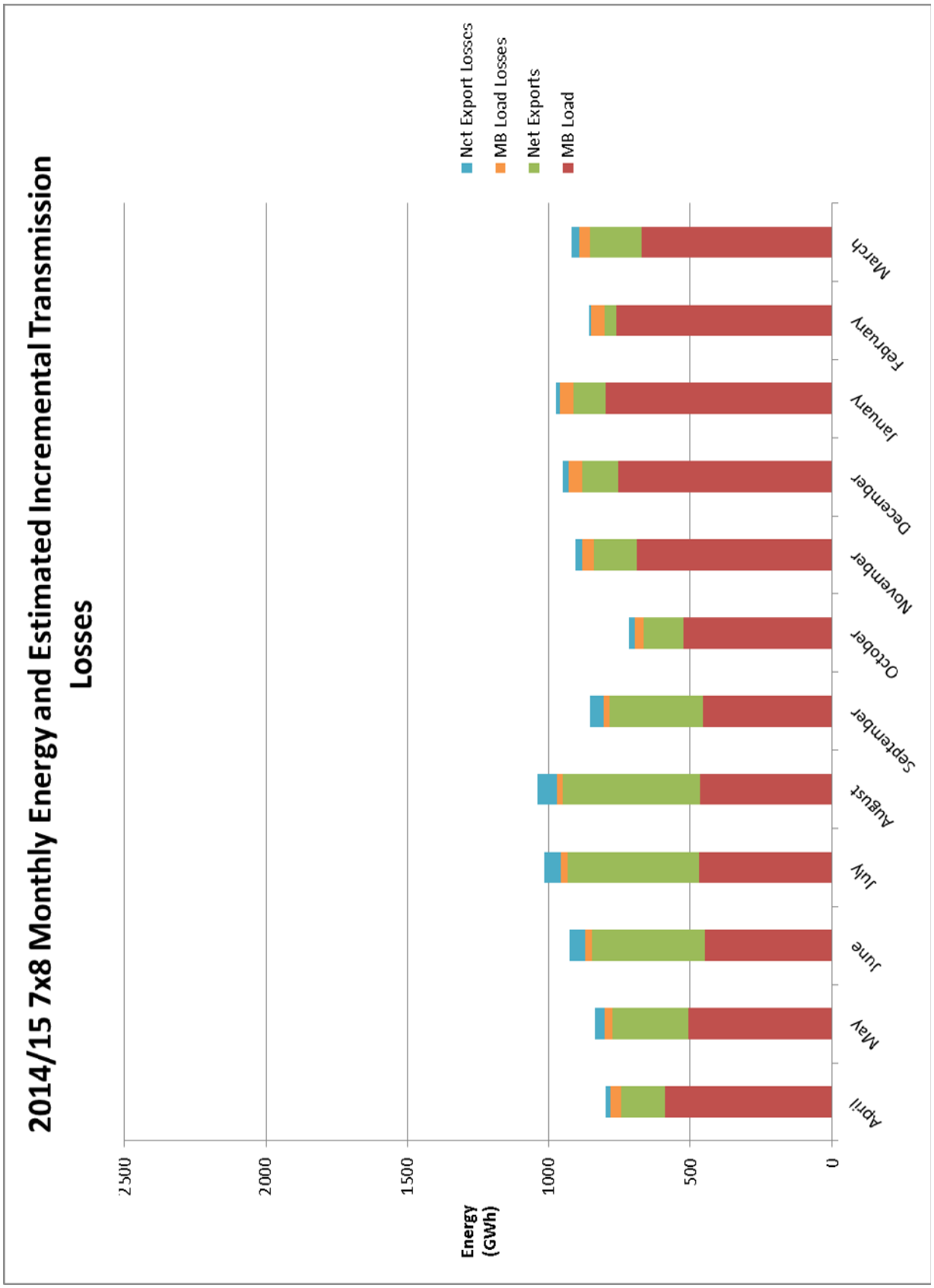
Substitute $I_{cb} = Load_{cb}/V$ *and* $I_{export} = Load_{export}/V$ *into the above.*

$$Loss_{cb}=Loss_{total} * (Load_{cb}^2/(Load_{cb}+Load_{export})^2$$

The above formula assumes common bus (domestic) load is supplied first and exports are supplied next. As mentioned above, this is a hypothetical situation as exports and imports can be scheduled at any time during the day.

Please see the charts below for the responses to parts a), c) and e).


2014/15 7x16 Monthly Energy and Estimated Incremental Transmission Losses
Net Export Losses
MB Load Losses
Net Exports
MB Load
Energy (GWh)
2500
2000
1500
1000
500
0
April
May
June
July
August
September
October
November
December
January
February
March


2014/15 7x8 Monthly Energy and Estimated Incremental Transmission Losses
Net Export Losses
MB Load Losses
Net Exports
MB Load
Energy (GWh)
2500
2000
1500
1000
500
0
April
May
June
July
August
September
October
November
December
January
February
March

The responses for PUB/MH I-20 b), d) and f) is contained in the following tables.

2014/15 7x16 Monthly Energy and Estimated Incremental Transmission Losses

Month	Net Exports	MB Load	MB Load Losses	Net Export Losses
April	588	1285	80	89
May	605	1174	71	92
June	819	1079	62	130
July	873	1156	65	132
August	860	1143	68	138
September	684	1101	62	101
October	287	1232	84	43
November	430	1549	96	61
December	445	1682	105	63
January	417	1772	107	56
February	259	1638	100	34
March	521	1482	89	74

2014/15 7x8 Monthly Energy and Estimated Incremental Transmission Losses

Month	Net Exports	MB Load	MB Load Losses	Net Export Losses
April	154	590	37	22
May	270	506	27	37
June	398	449	23	57
July	463	472	21	61
August	483	466	22	69
September	331	455	23	45
October	139	526	33	20
November	152	689	42	21
December	130	755	48	18
January	113	800	47	14
February	39	764	49	5
March	180	675	40	24

Section:	2014/15 Load Forecast NFAT MH Exhibit #176-1	**Page No.:**	Table 32 p.4
Topic:	Domestic & Export Peak Loads		
Subtopic:	Domestic & Export Peak Demand Profiles		
Issue:	Incremental Impacts of Exports on Cost Sharing		

PREAMBLE TO IR (IF ANY):

MH's peak domestic load growth is increasing/using greater share of hydraulic generation.

QUESTION:

Ref: Attached Graph, 2014/15 Domestic Peak Load vs Hydraulic Generation Capacity

a) Provide a graphical illustration of MH's 2014/15 actual peak monthly demand (megawatts) usage, separately depicting the 7 x 16 demand and the 7 x 8 nighttime demand.

b) Provide the data in both table and electronic form for the graph in (a).

c) Provide a revised graph (a) to include transmission losses (I2R) for each 2014/15 month, separately showing 7 x 16 peak and 7 x 8 off-peak demand (assuming zero exports).

d) Provide the data in both table and electronic form for the graph in (c).

e) Provide another version of above graph (c) but include peak export demands and incremental transmission losses (I2R) for each month, separately showing 7 x 16 peak and 7 x 8 off-peak demand.

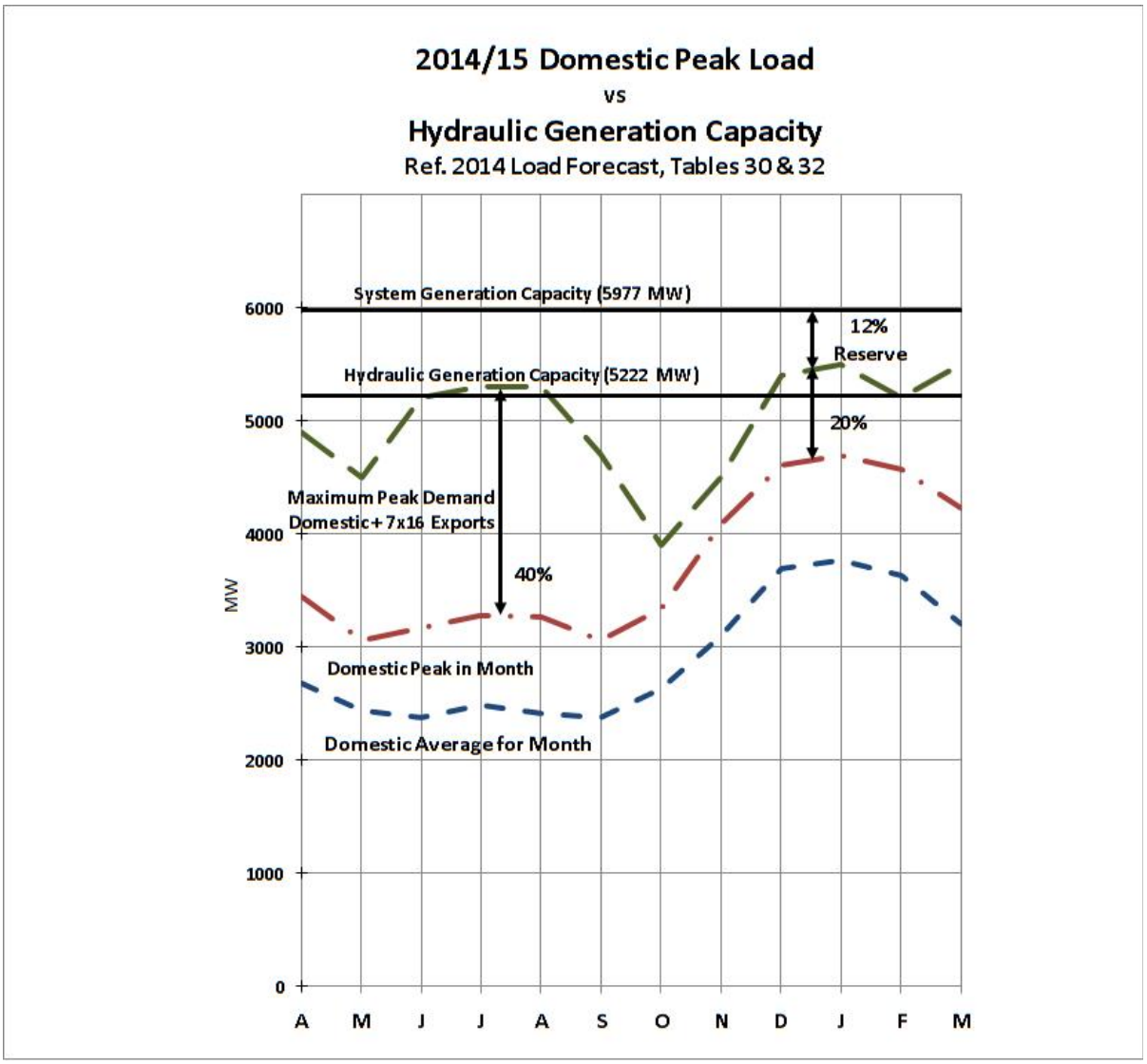
f) Provide the data for the graph in (e) in both table and electronic form.

The above formula assumes common bus (domestic) load is supplied first and exports are supplied next. As mentioned above, this is a hypothetical situation as exports and imports can be scheduled at any time during the day. The results of applying this loss formula are shown in the table below.

Case	A: Load at common bus (MW)	B: MB Exports (MW)	C: Total loss (MW)	D: $A^2/(A+B)^2$ *C Incremental Load losses (MW)	Domestic losses (percent of load at common bus)	E: C-D Incremental Export losses (MW)	Export losses (percent of MB exports)	Total losses (percent of generation)
05/06 Winter	3073	1557	397.6	175	5.70%	222	14.3%	8.1%
05/06 Summer	2365	2091	467.2	132	5.56%	335	16.0%	9.6%

4. Due to limited time available, monthly tabulation of the requested loads and losses could not be compiled. Please refer to PUB/MH II-464b for typical summer and winter peak losses that were analyzed for each of the last 3 years. Total losses, including a breakdown between HVDC and AC losses are given. PUB/MH II-330c can be referred to for an analysis of the losses that occur during various periods including:

- 5×16 summer (peak)
- 5×8 summer (night-time)
- 2×16 summer (weekends)
- 5×16 winter (peak)
- 5×8 winter (night-time)
- 2×16 winter(weekends)



RATIONALE FOR QUESTION:

Updated peak load/export profiles required to support cost allocations.

RESPONSE:

Loss calculations have been prepared using the method described in Needs For and Alternatives To (NFAT) submission MH Exhibit #176-1[1], where it is stated that:

> *The accurate calculation and tracking of system losses and allocation to various load classes including exports is a complex engineering calculation. For this reason*

[1] See http://www.pub.gov.mb.ca/nfat_hearing/NFAT%20Exhibits/MH-176-1.pdf

Manitoba Hydro has adopted a method for accounting purposes which determines total losses required to supply total load and assigns the same hourly loss/gain ratio to all load classes (residential, commercial, industrial, exports and imports).

With the exception of load flow studies based on actual hourly system data, Manitoba Hydro does not endorse other incremental loss accounting methodologies including the one requested in this Undertaking. These other methodologies have no technical justification for being more accurate or appropriate than the Manitoba Hydro average loss accounting method as they ignore:

a) That exports and imports can be scheduled simultaneously at any time during the day,
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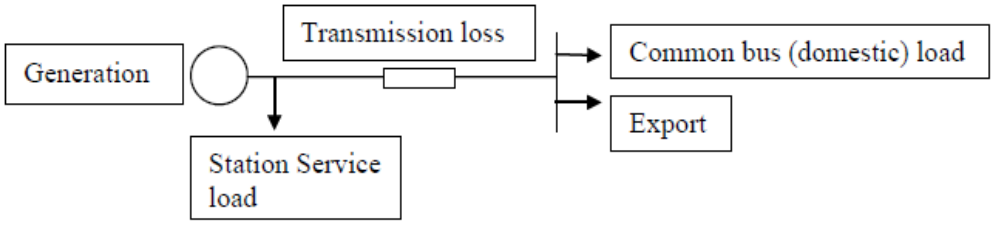

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$$I_{cb}^2R=Loss_{cb}$$

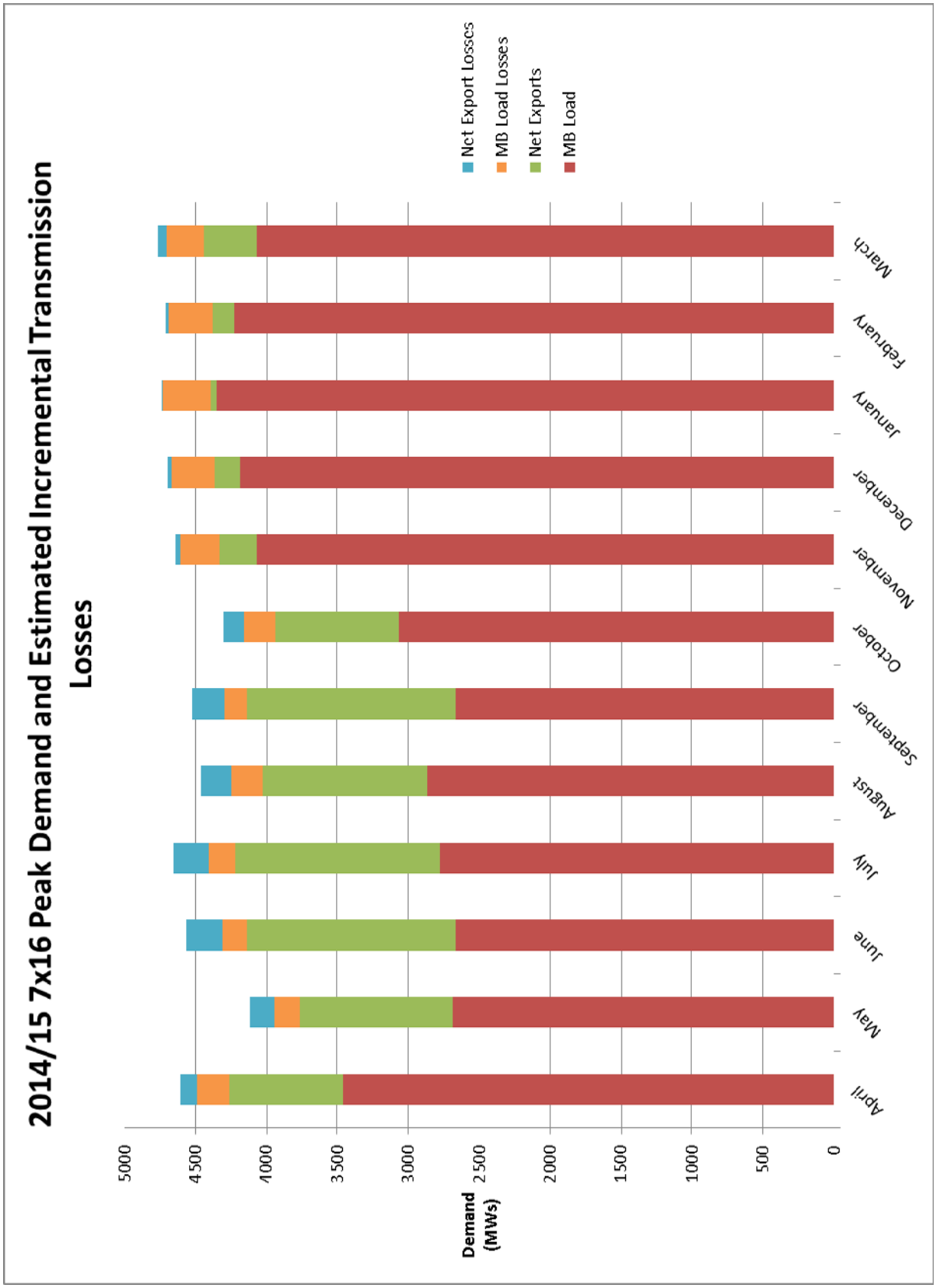
$$(I_{cb} + I_{export})^2R=Loss_{total}$$

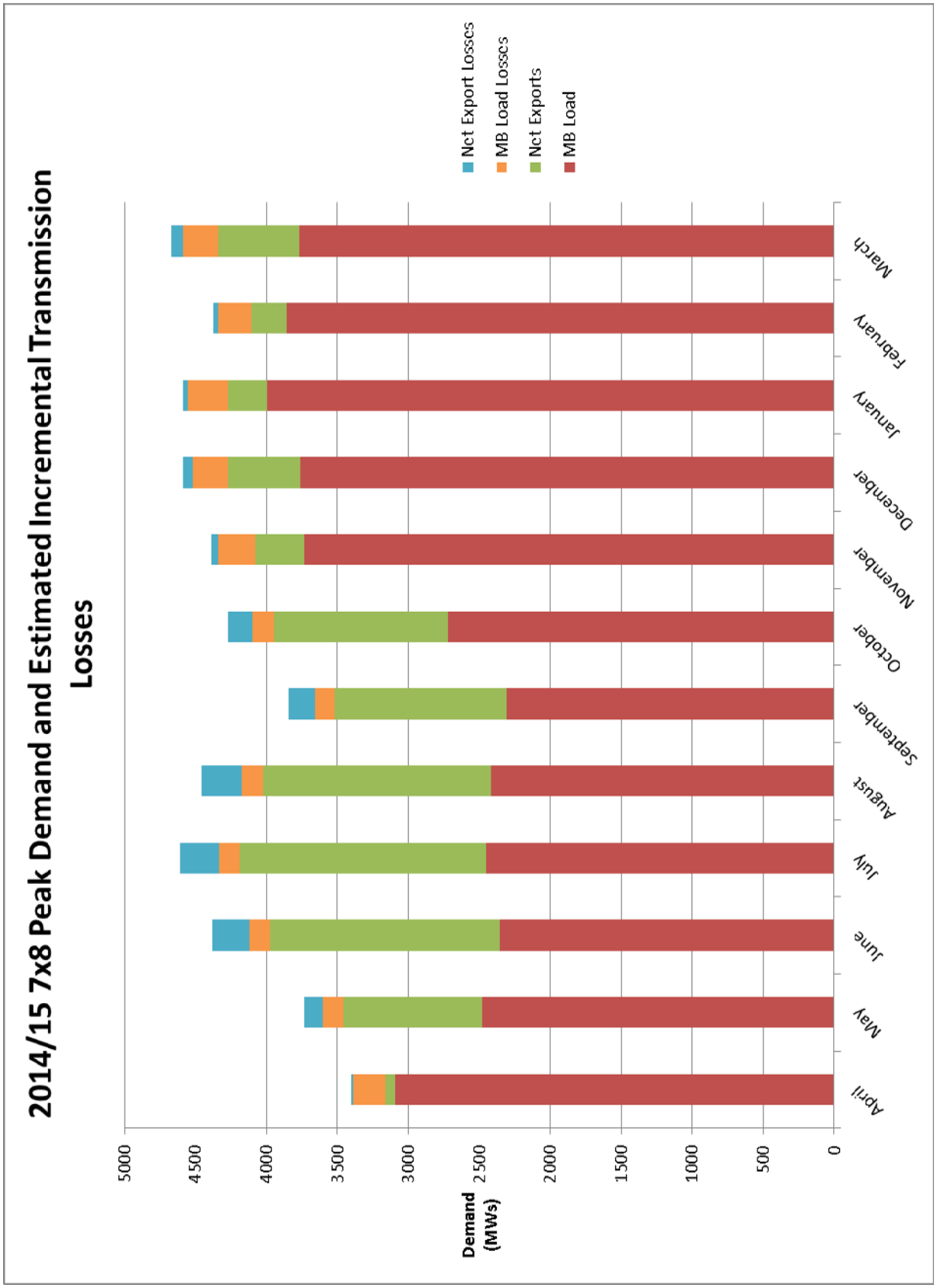
Substitute $I_{cb} = Load_{cb}/V$ *and* $I_{export} = Load_{export}/V$ *into the above.*

$$Loss_{cb}=Loss_{total} * (Load_{cb}^2/(Load_{cb}+Load_{export})^2$$

The above formula assumes common bus (domestic) load is supplied first and exports are supplied next. As mentioned above, this is a hypothetical situation as exports and imports can be scheduled at any time during the day.

Please see the charts below for the responses to parts a), c) and e).


2014/15 7x16 Peak Demand and Estimated Incremental Transmission Losses
Net Export Losses
MB Load Losses
Net Exports
MB Load
Demand (MWs)
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
April
May
June
July
August
September
October
November
December
January
February
March


2014/15 7x8 Peak Demand and Estimated Incremental Transmission Losses
Net Export Losses
MB Load Losses
Net Exports
MB Load
Demand (MWs)
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
April
May
June
July
August
September
October
November
December
January
February
March

The responses to PUB/MH I-21 b), d) and f) are contained in the following tables.

2014/15 7x16 Peak Demand and Estimated Incremental Transmission Losses

Month	MB Load	Net Exports	MB Load Losses	Net Export Losses
April	3464	799	224	115
May	2687	1077	180	173
June	2665	1467	180	253
July	2773	1441	192	251
August	2865	1162	219	214
September	2670	1464	162	227
October	3068	868	223	144
November	4073	254	280	36
December	4187	172	310	26
January	4348	45	336	7
February	4227	156	304	23
March	4068	367	272	51

2014/15 7x8 Peak Demand and Estimated Incremental Transmission Losses

Month	MB Load	Net Exports	MB Load Losses	Net Export Losses
April	3091	72	229	11
May	2479	981	140	132
June	2359	1617	142	262
July	2450	1738	143	275
August	2417	1609	155	274
September	2308	1211	139	184
October	2721	1226	155	171
November	3736	337	264	50
December	3762	512	244	71
January	3992	284	276	41
February	3859	250	235	31
March	3768	577	246	81

Section:	2015/16 GRA MFR 1 Attachment 16	**Page No.:**	2
Topic:	US Export Revenue and Sales		
Subtopic:	MISO Sales History & Forecasts		
Issue:	Firm and Opportunity Sales		

PREAMBLE TO IR (IF ANY):

PCOSS14 and PCOSS 14 Amended assume above average hydraulic generation for 2013/14.

QUESTION:

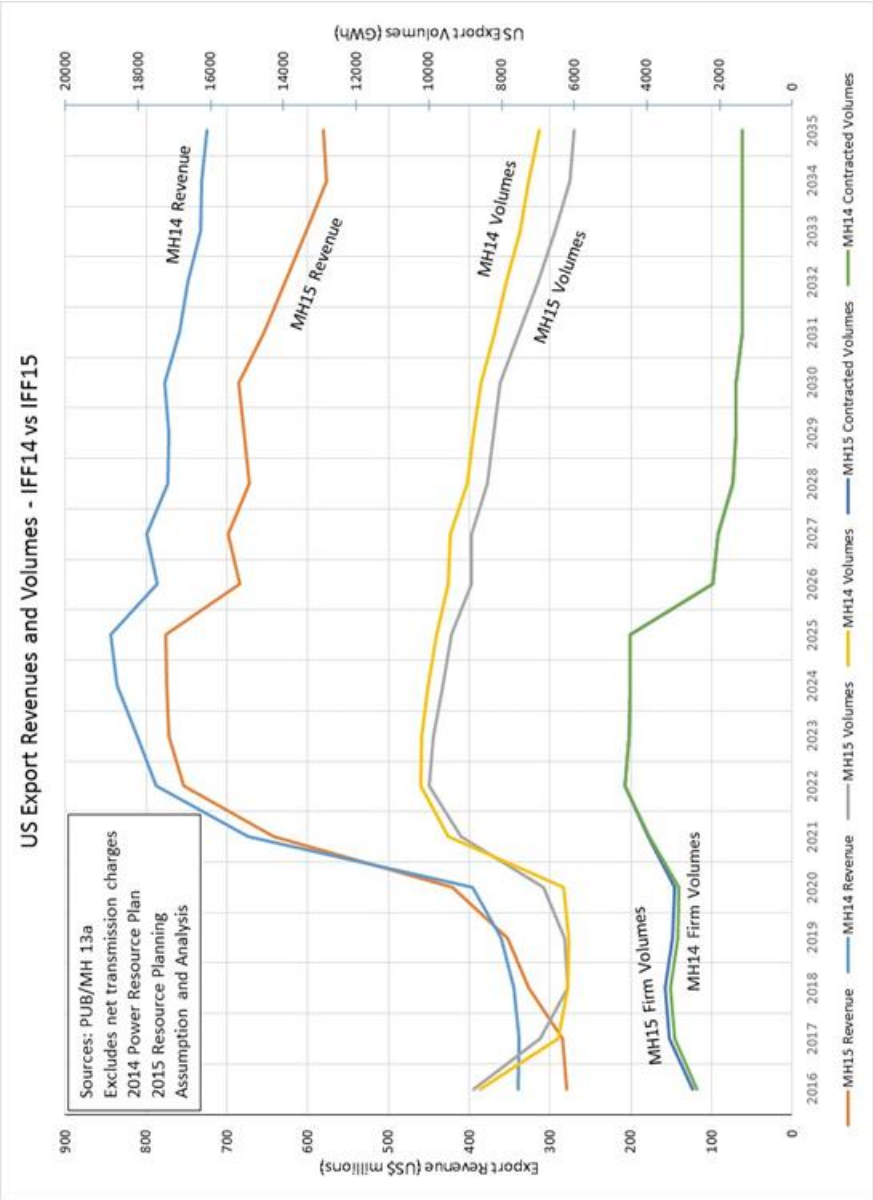
Ref: Attached Chart, US Export Revenue and Volumes – IFF14 vs IFF15

a) Confirm whether MH's export Business Plan involves maximizing the use of the U.S. 1850 MW intertie capability, firstly in the 5x16 peak period, secondly in the 2x16 weekend peak and thirdly in the 7x8 overnight off-peak.

b) Provide the monthly MISO sales (GWh) during each of the three periods in (a) for each of the last 8 years (2008/09 to 2015/16).

c) For or each of the last 8 years, provide a tabulation (GWh/$M) of the monthly: 1) firm-fixed price contract sales, 2) market-based contract sales, and 3) MISO market sales.

d) Provide a breakdown of monthly firm sales (GWh) for 2014/15 and 2015/16 by Permit Number for NSP/MP/WPS firm contracts and for NSP/GRE diversity contracts.



RATIONALE FOR QUESTION:

To establish the relative magnitude of Firm Contract sales and MISO Market Opportunity sales for PCOSS14/PCOSS14 Amended and future PCOSS(s).

RESPONSE:

a) Not confirmed. Manitoba Hydro does not make exports based upon an allocation stack tied to the three time periods mentioned in the question.

With respect to exports made under contract they are made in accordance with the contractual provisions. With regard to market sales to MISO, the IESO, or the AESO hourly offers are made and should they clear based upon the market clearing price, they will be delivered in the cleared hours. Manitoba Hydro makes hourly offers in such a manner as to maximize export revenues not to maximize use of the interconnections in specific time periods.

That being said power prices are typically highest during the 5x16 peak period, with prices in the weekend 2x16 period typically 20% lower, followed by the overnight off-peak period when average prices are generally the lowest.

b)

MISO Physical Sales			
	GWh		
Date	5 x 16	2 x 16	7 x 8
Apr-08	144	133	152
May-08	140	139	113
Jun-08	132	155	67
Jul-08	116	89	335
Aug-08	78	192	384
Sep-08	212	174	339
Oct-08	133	148	303
Nov-08	112	183	223
Dec-08	22	62	43
Jan-09	27	34	26
Feb-09	39	56	38
Mar-09	17	79	37
Apr-09	158	107	159
May-09	156	79	74
Jun-09	138	61	66
Jul-09	203	59	108
Aug-09	169	73	98
Sep-09	177	129	296
Oct-09	217	190	364
Nov-09	205	187	211
Dec-09	45	63	23
Jan-10	40	138	77
Feb-10	44	94	56
Mar-10	180	115	88
Apr-10	205	126	102
May-10	69	41	1
Jun-10	145	118	119
Jul-10	169	172	290
Aug-10	158	168	289
Sep-10	164	145	219
Oct-10	202	189	256
Nov-10	103	69	167
Dec-10	13	66	77

MISO Physical Sales			
	GWh		
Date	5 x 16	2 x 16	7 x 8
Jan-11	14	57	66
Feb-11	26	62	88
Mar-11	55	81	138
Apr-11	114	92	173
May-11	221	138	227
Jun-11	189	121	199
Jul-11	159	207	357
Aug-11	152	150	341
Sep-11	103	88	185
Oct-11	88	112	178
Nov-11	56	82	92
Dec-11	21	47	43
Jan-12	30	58	47
Feb-12	19	27	8
Mar-12	114	39	20
Apr-12	92	73	13
May-12	216	112	56
Jun-12	164	153	136
Jul-12	165	189	331
Aug-12	186	181	327
Sep-12	172	177	221
Oct-12	143	77	28
Nov-12	54	55	41
Dec-12	14	19	4
Jan-13	17	26	1
Feb-13	53	47	11
Mar-13	86	132	46
Apr-13	94	99	57
May-13	279	175	229
Jun-13	233	227	319
Jul-13	228	195	375
Aug-13	222	225	378
Sep-13	164	187	244

MISO Physical Sales			
	GWh		
Date	5 x 16	2 x 16	7 x 8
Oct-13	227	152	301
Nov-13	77	70	107
Dec-13	15	28	7
Jan-14	30	18	16
Feb-14	40	28	20
Mar-14	115	84	40
Apr-14	145	125	103
May-14	141	129	186
Jun-14	195	176	302
Jul-14	206	171	354
Aug-14	162	226	378
Sep-14	157	113	235
Oct-14	15	38	75
Nov-14	102	108	145
Dec-14	101	101	103
Jan-15	105	97	73
Feb-15	32	27	15
Mar-15	150	119	142
Apr-15	284	148	221
May-15	278	158	254
Jun-15	226	127	273
Jul-15	243	111	222
Aug-15	288	188	303
Sep-15	226	118	239
Oct-15	134	104	231
Nov-15	263	135	127
Dec-15	231	91	106
Jan-16	94	75	31
Feb-16	169	101	84

c)

	US Dependable Fixed Price Sales	US Opportunity Fixed Price Sales	US Market Sales
Month	$/MWh	$/MWh	$/MWh
Apr-08	38.41	76.64	48.44
May-08	38.62	75.30	34.68
Jun-08	39.05	84.15	39.71
Jul-08	38.60	89.83	39.38
Aug-08	39.94	91.46	32.72
Sep-08	40.67	47.19	28.85
Oct-08	47.26	83.10	31.14
Nov-08	48.06	81.19	35.34
Dec-08	46.91	89.93	60.33
Jan-09	47.37	87.09	48.86
Feb-09	48.68	89.60	42.09
Mar-09	48.28	87.57	30.23
Apr-09	46.44	119.40	22.36
May-09	39.22	32.35	17.61
Jun-09	45.30	38.25	19.65
Jul-09	41.73	21.15	15.40
Aug-09	42.40	36.75	16.73
Sep-09	42.15	22.98	17.19
Oct-09	43.04	30.72	22.56
Nov-09	42.24	33.25	20.83
Dec-09	41.22	36.65	33.21
Jan-10	41.94	0.00	39.49
Feb-10	41.45	45.26	39.46
Mar-10	40.00	38.99	26.53
Apr-10	40.43	32.92	22.39
May-10	39.45	36.04	39.95
Jun-10	39.65	25.26	27.50
Jul-10	38.35	0.00	26.44
Aug-10	39.65	24.97	29.29
Sep-10	38.59	17.92	19.86
Oct-10	38.40	29.55	22.18
Nov-10	38.69	0.00	20.60
Dec-10	36.74	0.00	25.43
Jan-11	37.02	0.00	27.03
Feb-11	35.98	0.00	19.91

Month	US Dependable Fixed Price Sales $/MWh	US Opportunity Fixed Price Sales $/MWh	US Market Sales $/MWh
Mar-11	35.90	19.24	21.09
Apr-11	35.78	18.02	21.82
May-11	37.06	21.98	18.17
Jun-11	36.48	21.97	18.44
Jul-11	36.02	31.01	27.33
Aug-11	36.97	22.77	24.11
Sep-11	39.39	17.33	19.66
Oct-11	38.01	24.01	17.36
Nov-11	39.01	0.00	21.62
Dec-11	38.14	0.00	20.91
Jan-12	37.70	0.00	20.07
Feb-12	37.00	0.00	23.96
Mar-12	37.47	33.97	19.89
Apr-12	37.87	33.61	21.82
May-12	40.64	35.07	27.75
Jun-12	39.53	32.81	20.40
Jul-12	38.77	38.49	26.19
Aug-12	38.19	23.98	18.74
Sep-12	38.29	23.05	18.13
Oct-12	39.25	31.99	26.47
Nov-12	38.99	32.67	25.37
Dec-12	38.26	34.81	33.68
Jan-13	38.43	35.17	31.34
Feb-13	39.55	31.15	29.33
Mar-13	39.06	35.40	30.63
Apr-13	38.73	34.61	31.62
May-13	40.51	29.10	26.32
Jun-13	40.93	35.03	24.20
Jul-13	39.96	36.85	26.22
Aug-13	41.01	36.90	24.63
Sep-13	40.09	27.50	23.88
Oct-13	40.86	30.68	25.30
Nov-13	41.52	28.57	27.22
Dec-13	41.69	42.38	38.83
Jan-14	43.57	49.04	70.36

Month	US Dependable Fixed Price Sales $/MWh	US Opportunity Fixed Price Sales $/MWh	US Market Sales $/MWh
Feb-14	43.39	0.00	65.97
Mar-14	43.31	0.00	40.07
Apr-14	42.93	33.95	29.98
May-14	42.79	31.89	28.73
Jun-14	41.77	31.60	24.11
Jul-14	42.51	28.68	24.78
Aug-14	42.38	30.84	27.00
Sep-14	43.88	26.92	21.32
Oct-14	44.35	27.22	22.65
Nov-14	45.00	34.38	28.53
Dec-14	45.68	47.39	29.68
Jan-15	50.08	50.23	29.26
Feb-15	49.25	49.46	41.13
Mar-15	49.94	49.97	26.60
Apr-15	48.56	47.25	24.50
May-15	73.43	38.46	23.39
Jun-15	72.21	42.27	25.36
Jul-15	75.14	51.33	31.81
Aug-15	76.65	48.42	29.87
Sep-15	77.47	45.34	29.00
Oct-15	76.27	42.06	22.29
Nov-15	76.36	52.46	21.24
Dec-15	78.97	54.13	24.74
Jan-16	81.68	0.00	29.98
Feb-16	79.43	0.00	25.77

d)

Note there was no Firm WPS contract for the period defined in this question.

				Diversity			
	NSP	MP	NSP (Incl Diversity)	NSP		GRE	
	EPE-224	EPE-392	EPE-374	EPE-33	EPE-34	EPE-387	EPE-35
Apr-14	171						93
May-14	153						63
Jun-14	167			34	26		105
Jul-14	178			54	41		110
Aug-14	168			54	41		112
Sep-14	163			28	21		102
Oct-14	136						39
Nov-14	160						
Dec-14	184						
Jan-15	176						
Feb-15	160						
Mar-15	175						
Apr-15	176						
May-15			179			110	
Jun-15		23	180			99	
Jul-15		25	191			105	
Aug-15		24	184			80	
Sep-15		24	186			100	
Oct-15		24	175			88	
Nov-15		24	94				
Dec-15		25	101				
Jan-16		25	101				
Feb-16		24	103				

Section:	2014/15 Power Resource Plan	**Page No.:**	
Topic:	Generation Resources		
Subtopic:	HVDC and HVAC systems		
Issue:	Actual System Utilization		

PREAMBLE TO IR (IF ANY):

As per the attached chart, pre-Bipole III, MH's Lower Nelson River hydraulic generation output was potentially constrained by the available capacity of Bipoles I & II.

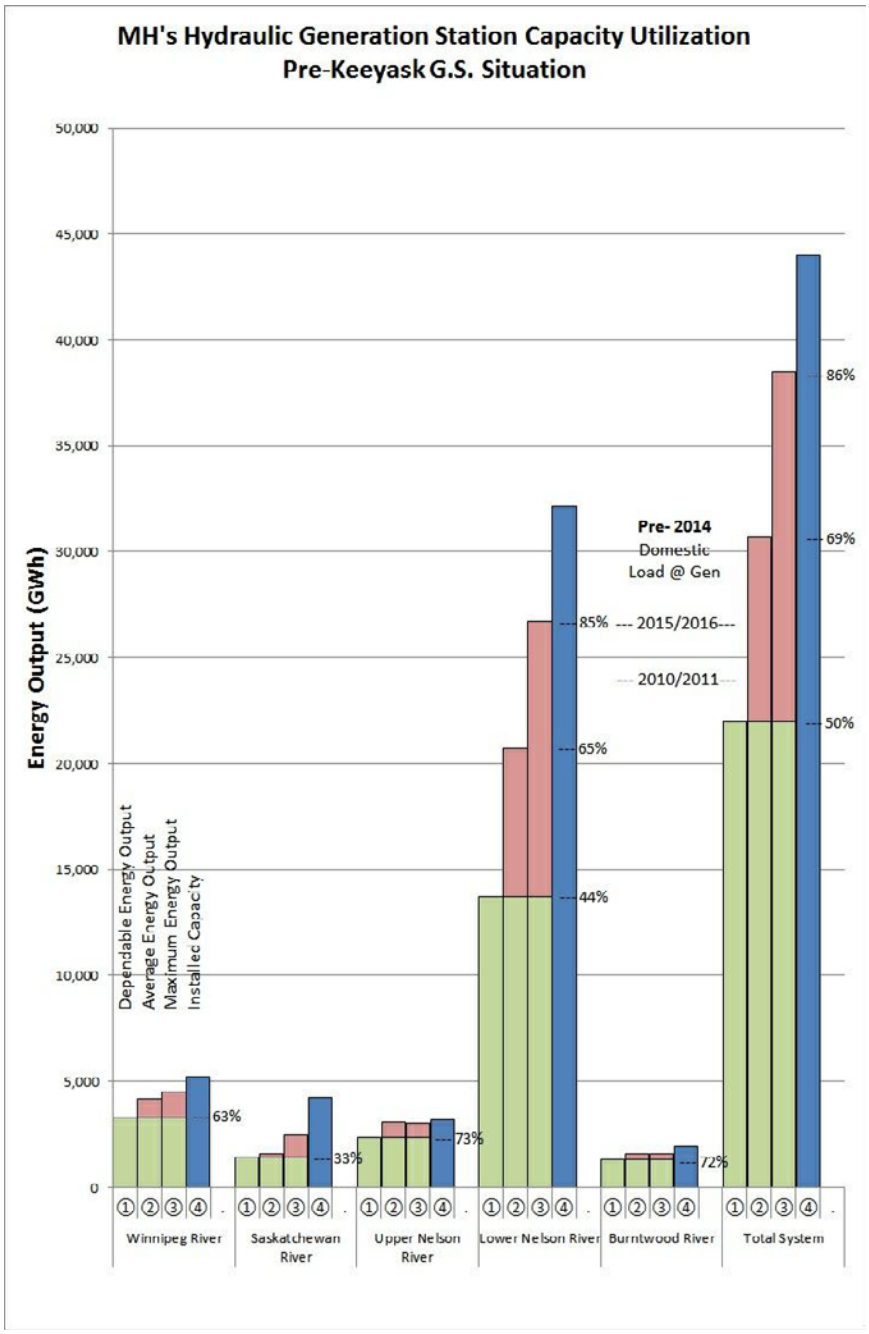
QUESTION:

a) Confirm the correctness attached table of MH's HVDC and HVAC Generation Resources. If, not provide a revised table.

MH's HVDC and HVAC Generation Resources

Watershed	No. of G.S.	Capacity (MW)	Generation Output Firm (GWh)	Average (GWh)	Maximum (GWh)
Winnipeg River (AC) (Pre 1960)	6	590	3300	4100	4400
Saskatchewan River (AC) (1962)	1	479	1370	1500	2500
Upper Nelson River (AC) (Pre 1976)	2	353	2260	3100	3000
Lower Nelson River (DC) Post 1971	3	3570	13780	20500	26700
Burntwood River (AC) (2012-13 In-service)	1	200	1220	1500	1500
Subtotal		**5192**	**21930**	**30700**	**38100**

Thermal Generation			**Max**	**Min**
Brandon Coal (AC)	1	105	811	270
Brandon SCCTs (AC)	2	280	2254	40
Selkirk Natural Gas (AC)	1	132	953	30
Subtotal		**517**	**4018**	**340**
Wind Generation (AC)	2 sites	268	900	771
MH System Resources		5977	26948	
MISO Imports		605	?	
Total Resources		**6582**	**?**	



RATIONALE FOR QUESTION:

To understand the functional usage of MH's HVDC system with Bipoles I & II and also Bipole III in the future.

RESPONSE:

The table is not confirmed. A corrected table using information from the NFAT Business Case, Chapter 5, Table 5.1 (p 3) is provided below.

MH's HVDC and HVAC Generation Resources

			Generation Output		
Watershed	**No. of G.S.**	**Capacity** (MW)	**Firm** (GWh)	**Average** (GWh)	**Maximum** (GWh)
Winnipeg River (AC)	6	553	2325	4030	4572
Saskatchewan River (AC)	1	480	1320	1555	1790
Upper Nelson River (AC)	2	420	2455	3105	3270
Lower Nelson River (DC)	3	3562	15030	20840	26130
Burntwood River (AC)	1	200	1250	1520	1650
Laurie River (AC)	2	10	40	60	80
Subtotal		**5225**	**22420**	**31110**	**37492**
	No. of Units				
Thermal Generation			**Max**	**Min**	
Brandon Coal (AC)	1	105	811	125	125
Brandon SCCTs (AC)	2	280	2354	23	23
Selkirk Natural Gas (AC)	2	132	953	18	18
Subtotal		**517**	**4118**	**166**	**166**
MH System Resources		**5742**	**26538**	**31276**	**37658**
Wind Generation (AC)	2 sites		777	914	914
MISO Imports		550	2705	Varies	Minimal
MISO Purchases			363	Varies	Minimal
Total Resources		**6292**	**30383**	**32190**	**38572**

Section:	2014/15 Power Resource Plan	**Page No.:**	
Topic:	Generation Resources		
Subtopic:	HVDC and HVAC systems		
Issue:	Actual System Utilization		

PREAMBLE TO IR (IF ANY):

As per the attached chart, pre-Bipole III, MH's Lower Nelson River hydraulic generation output was potentially constrained by the available capacity of Bipoles I & II.

QUESTION:

b) Confirm whether MH's firm/dependable energy resource is 50% derived from MH's HVDC-connected hydraulic generation. If not, please indicate the percentage and explain.

RATIONALE FOR QUESTION:

To understand the functional usage of MH's HVDC system with Bipoles I & II and also Bipole III in the future.

RESPONSE:

Confirmed.

The dependable energy from the Manitoba Hydro system is an aggregate total of available resources during the lowest historic system inflow conditions. Under such inflow conditions, it is expected that nearly 50% (15030 GW.h of 30383 GW.h) of the energy available to meet firm loads would be from the plants on the Lower Nelson, which are connected to the HVDC system. It should be noted that these same generating stations would provide nearly 60% of the total system capacity and nearly 70% of the hydro system capacity to meet peak loads which is a key factor contributing to the sizing of the HVDC system. Manitoba Hydro plans and operates its system, including generation, AC transmission and HVDC systems, to meet

peak demand/capacity requirements and dependable energy requirements with consideration of equipment limitations, outages and contingency events.

In addition under higher than the lowest historic inflow conditions, the overall system would be operated to reduce system costs such that incrementally greater generation available from the Nelson River stations could be used to offset thermal generation and imports thereby serving dependable/firm loads.

Section:	2014/15 Power Resource Plan	**Page No.:**	
Topic:	Generation Resources		
Subtopic:	HVDC and HVAC systems		
Issue:	Actual System Utilization		

PREAMBLE TO IR (IF ANY):

As per the attached chart, pre-Bipole III, MH's Lower Nelson River hydraulic generation output was potentially constrained by the available capacity of Bipoles I & II.

QUESTION:

c) Confirm whether the utilization of HVDC transmission in excess of 13,780 GWh can only serve additional opportunity export sales (0 to 12,922 GWh). If not, please explain.

d) Confirm whether the attached Figure C-4 illustrates the hydraulic generation station outputs with dependable/average/maximum flows conditions. If not, provide a revised version.

e) Indicate the percentage share of MH's total hydraulic generation that is attributable to the Lower Nelson G.S. and transmitted via the HVDC system. See attached Figure C-4.

f) Provide a tabular comparison of MH's installed G.S. capacity and the Bipole I & II transmission capability, indicating the assumptions on outages of both generation and transmission systems that would affect the maximum capacities.

MH's HVDC and HVAC Generation Resources

			Generation Output		
Watershed	**No. of G.S.**	**Capacity** (MW)	**Firm** (GWh)	**Average** (GWh)	**Maximum** (GWh)
Winnipeg River (AC) (Pre 1960)	6	590	3300	4100	4400
Saskatchewan River (AC) (1962)	1	479	1370	1500	2500
Upper Nelson River (AC) (Pre 1976)	2	353	2260	3100	3000
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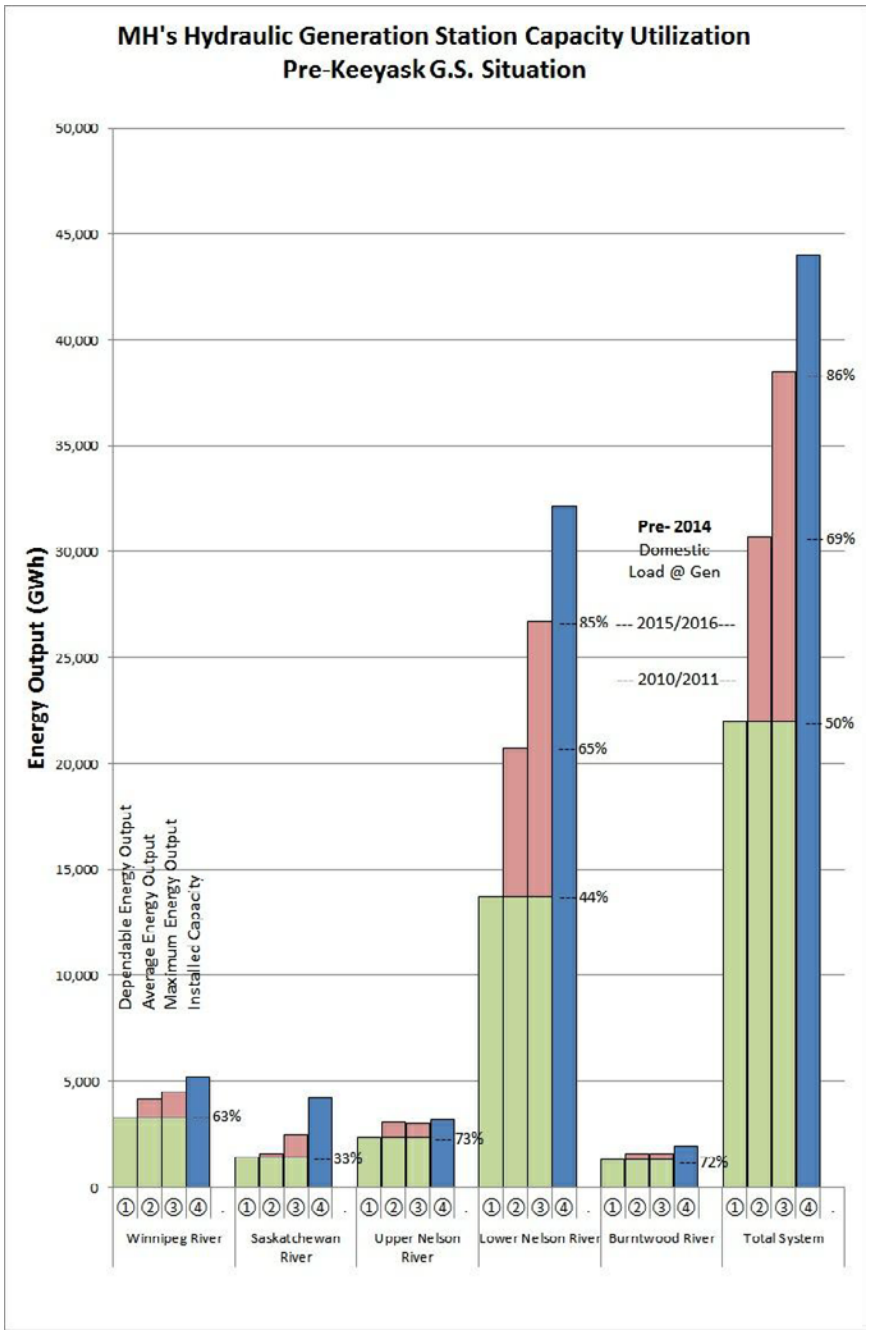
Burntwood River (AC) (2012-13 In-service)	1	200	1220	1500	1500
Subtotal		**5192**	**21930**	**30700**	**38100**

Thermal Generation			**Max**	**Min**
Brandon Coal (AC)	1	105	811	270
Brandon SCCTs (AC)	2	280	2254	40
Selkirk Natural Gas (AC)	1	132	953	30
Subtotal		**517**	**4018**	**340**
Wind Generation (AC)	2 sites	268	900	771
MH System Resources		5977	26948	
MISO Imports		605	?	
Total Resources		**6582**	**?**	



RATIONALE FOR QUESTION:

To understand the functional usage of MH's HVDC system with Bipoles I & II and also Bipole III in the future.

RESPONSE:

c) It is not confirmed that the utilization of HVDC transmission in excess of 13,780 GWh can only serve additional opportunity export sales. Dependable energy is the total system energy that is expected to be available during the lowest historic system inflow condition as well as thermal generation, import energy, and contractual arrangements (such as adverse water clauses). Lower Nelson generation in excess of dependable levels would be used to displace higher cost operations such as reducing imports, and reducing thermal generation. Other higher value uses of generation would include replenishing water in storage for later use and/or fulfillment of short-term firm sales.

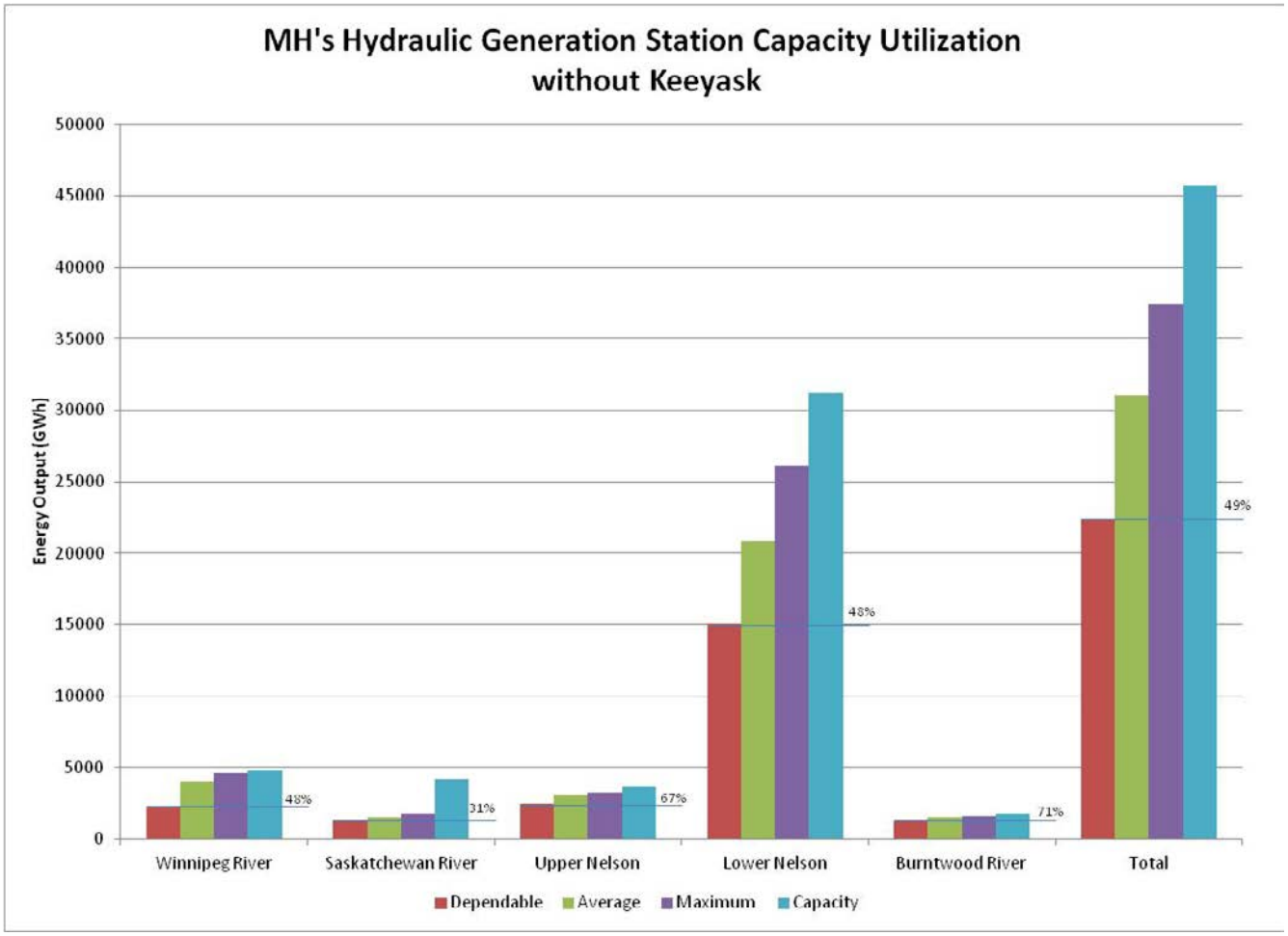
d) Not confirmed. Energy values for generation are as shown in the NFAT Business Case Chapter 5 (Page 3 of 61), and illustrated, as requested below. The percentage values on the chart reflect the ratio of dependable energy to the hypothetical maximum.

Dependable energy is the expected annual generation from the hydraulic plants located on each identified river reach, under a repeat of the lowest historic system inflow condition (dependable inflows).

Average energy is the average of the expected generation from the hydraulic plants on each identified river reach, based on a repeat of each of the historic 102 years of system inflows. It is not the generation based on the average system inflow condition.

Maximum energy is the greatest annual generation from the hydraulic plants on each identified river reach, based on historic system inflows. It is not necessarily the generation based on the greatest inflow.

Capacity is the hypothetical maximum annual generation from the hydraulic plants on each identified river reach, based on the plants operating continuously at plant ratings for the all hours of an entire year.



e) The percentage share of MH's total hydraulic generation that is attributable to the Lower Nelson Generating Stations and transmitted via the HVDC system is 68% of the hydraulic system capacity, 67% of the dependable hydraulic energy, 67% of the average hydraulic energy, and 70% of the maximum hydraulic generation.

f) Capacity of the Lower Nelson Plants connected to the HVDC system is as stated in NFAT Chapter 5 filing (Page 3 of 61).

Generating Station	Capacity	Bipole I & II	Comment
Kettle	1220 MW	3554 MW	Network Interconnection Transmission Service rating
Long Spruce	1007 MW		
Limestone	1335 MW		
Total	3562 MW	3554 MW	

Based on transmission studies there is sufficient transmission available to permit the transfer of up to 3554 MW of firm generation capacity. This transmission capacity is referred to as Network Interconnection Transmission Service (NITS).

Section:	Main Submission; Appendix 5	**Page No.:**	20 / 14
Topic:	Generation and Transmission		
Subtopic:	Functionalization of HVDC		
Issue:	Functionalization of Transmission facilities as Generation		

PREAMBLE TO IR (IF ANY):

Christensen Associates states as follows:

"The existing Bipole facilities are functionalized as Generation and allocated on Weighted Energy on account of their role in transporting power from northern generators to southern load centers."

"For cost allocation, the appropriateness of functionalizing the Company's Bipole facilities as generation can be gauged by applying several general criteria, as follows:

- Are observed flows on the facility representative of the net of numerous counter flows between points of power injections and load withdrawals?
- Are flows on the facility of a uniform direction?
- Does the facility provide improved reliability for the AC meshed network as a whole, in isolation of any specific generation facility?
- Does the facility provide increased power flow capability to the AC meshed network?"

QUESTION:

With reference to the four-point test set out by Christensen Associates above, please explain why the functionalization of HVDC facilities as Generation differs from that of other transmission facilities that accomplish the same task of transporting power from northern generators to remote load centres, for example the AC transmission lines to Churchill or Oxford House.

RATIONALE FOR QUESTION:

RESPONSE:

Response prepared by Christensen Associates:

Manitoba Hydro's HVDC facilities are vital to system-wide reliability, without reference to any single generator. In contrast, remotely-sited AC transmission lines, which may have, predominantly or exclusively, one-way flows, such facilities have no measurable impact on the reliability of Manitoba Hydro's meshed AC network, concentrated in the southern region of Province.

Second, remote transmission facilities, over an extended life often reaching beyond fifty years, may provide for the energy requirements (demand for electricity) of unexpected yet highly local economic development over future decades, such as remote towns and villages. Thus, remotely-sited AC facilities, which at the time of implementation may be characterized as one way flows reflecting generation supply served into meshed AC networks, may accommodate unanticipated, remote-sited loads in later decades. As a consequence, the role of the facilities may evolve from that of a generator lead to a more general role of transmission. DC facilities, on the other hand, are specialized and cannot readily accommodate or enable economic development in remote areas through interconnection.

This is an important consideration for fairly remote regions because, at the time of implementation of remote AC transmission facilities, locales of expanding economic activity in the future cannot be easily anticipated. So, if a transmission line, originally dedicated to remotely-sited generation, is not too far away, unanticipated loads can interconnect to the facilities as these load centers arise. Interconnection involves sectionalizing the line. Note, moreover, that interconnection of newly formed load centers to remotely-sited AC transmission lines may precipitate load following issues and, depending on the size of the new load center, flows on a section of the line can become bidirectional.

Section:	2014/15 Power Resource Plan	**Page No.:**	
Topic:	Hydraulic Generation/Non-hydraulic Generation Resources		
Subtopic:	Fixed Costs to Opportunity Sales		
Issue:	Allocation of Fixed Costs		

PREAMBLE TO IR (IF ANY):

MH's ability to export surplus electricity is derived from a 'Surplus by Design' planning strategy.

QUESTION:

a) Confirm that MH expects to assign no G&T fixed costs to opportunity sales. Explain why opportunity sales would not be reduced if:
   - Lower Nelson G.S. capacity was sized to match dependable energy output.
   - No wind purchases were available.
   - No thermal plant existed.

b) Quantify the opportunity export reductions (GWh) that would result under each of the above scenarios for the years 2013/14, 2018/19, and 2021/22.

c) Quantify the additional power purchases (GWh) that would be required to meet firm loads under both dependable flow and average flow for the years 2013/14, 2018/19, and 2021/22 reflecting each assumption in (a).

RATIONALE FOR QUESTION:

Reduced hydraulic generation/non-hydraulic generation resources would suggest lower energy surpluses.

RESPONSE:

The preamble to this question refers to a "Surplus by Design" planning strategy. To clarify this should not be interpreted to mean the goal of the design is to have surplus. Rather it means that with an energy planning criteria related to dependable flow conditions, the consequence is that there will be surplus energy available under all other flow conditions.

And from a capacity perspective MH does not build surplus capacity for its own sake, rather it means that with a capacity planning criteria related to peak load demands and capacity planning reserve margins, the consequence is that there will be surplus capacity available during non-peak load conditions when the system is intact.

Given that there will generally be both surplus capacity and surplus energy available, MH uses these surplus resources to generate electricity when profitable to generate export revenues.

a) Manitoba Hydro confirms that it has not assigned any G&T fixed costs to opportunity sales.

   Manitoba Hydro cannot confirm the effect on opportunity sales under the hypothetical scenarios described. Manitoba Hydro's system has been designed to meet the load of domestic customers at the least cost and to ensure that Manitoba customers have reliable service during all time periods, including peak periods.

   The hypothetical scenarios suggested would eliminate capacity and/or dependable energy resources that are needed to meet firm load requirements. In addition, if resources such as wind and thermal are removed, other resources and additional facilities would be required to serve domestic load and maintain reliability. It would be speculative to assume what alternative development plans Manitoba Hydro would have undertaken to meet Manitoba load requirements in the hypothetical scenarios described. These alternative development plans would affect all costs and revenues, not just opportunity sales.

   Manitoba Hydro's generation planning criteria consists of two components, both of which must be satisfied to ensure an adequate supply. First, there is a capacity criterion, used to determine the minimum quantity of generation capacity required. Second, there is an energy criterion, used to determine the minimum quantity of energy required. Meeting

only one of the criteria would leave insufficient resources to meet Manitoba load during some hours.

Response to parts b) and c):

Please see Manitoba Hydro's response to part a).

Section:	Attachment 3	**Page No.:**	
Topic:	Exports/Imports		
Subtopic:	Diversity Sales/Purchases		
Issue:	MISO Benefits vs MH Benefits		

PREAMBLE TO IR (IF ANY):

Diversity sales are high in contrast with Diversity purchases which are minimal.

QUESTION:

a) Provide a graphical comparison of MH's monthly Diversity sales and purchases (GWh) for NSP contracts and GRE contracts for 2013/14, 2014/15 and 2015/16.

b) Indicate on a monthly basis the portion (GWh) of the 7x16 and 7x8 sales as well as purchases during the same three years for the NSP/GRE Diversity contracts.

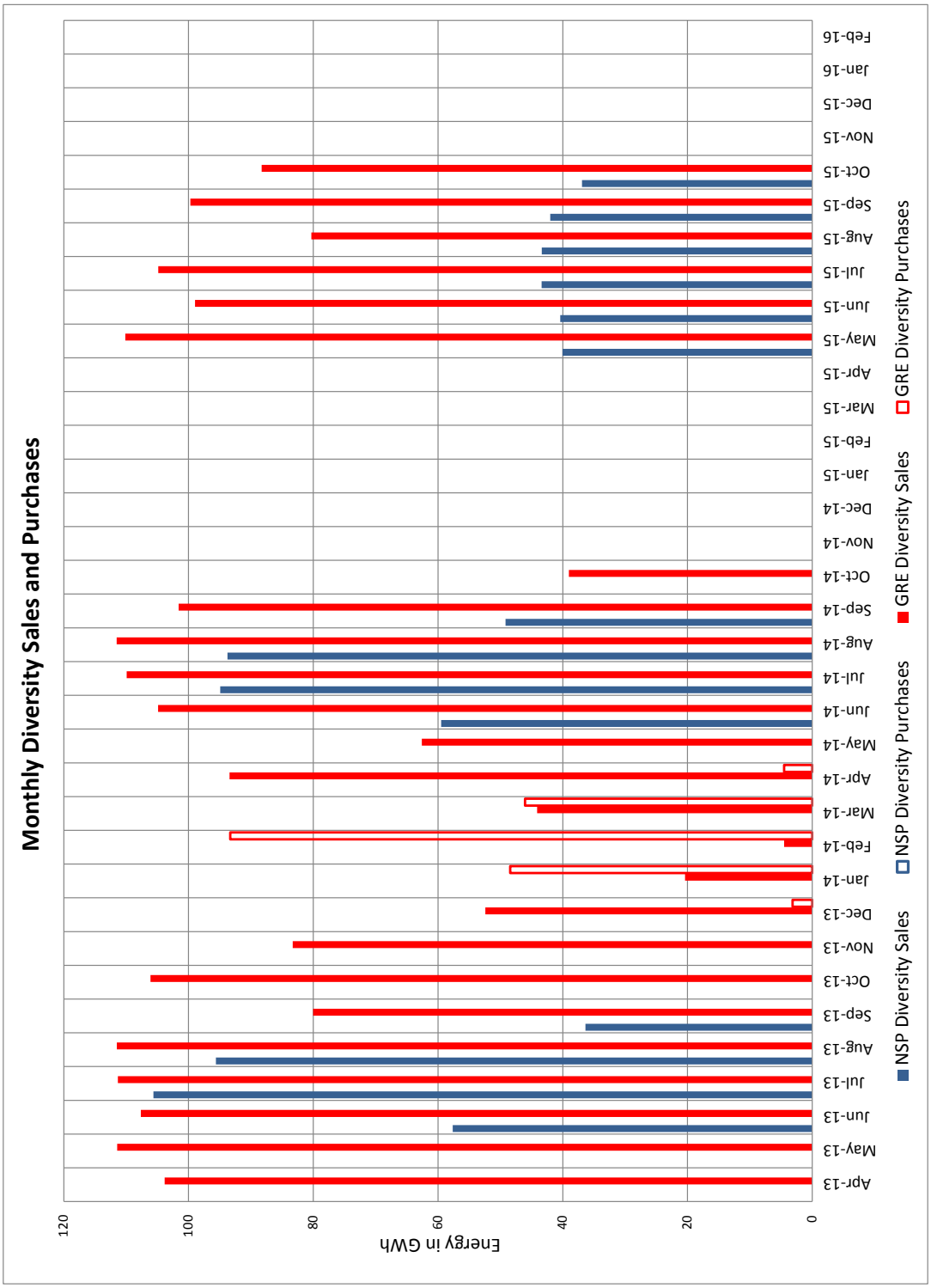
c) Explain the 2015/16 NEB reporting treatment of NSP Diversity and GRE Diversity contracts.

RATIONALE FOR QUESTION:

With the above average hydraulic generation in the last 10 years, NSP/GRE utilities secured reliable capacity/energy resources; MH did not call on either Diversity contract for capacity/energy shortfalls.

RESPONSE:

a)


Monthly Diversity Sales and Purchases
Energy in GWh
0
20
40
60
80
100
120
Apr-13
May-13
Jun-13
Jul-13
Aug-13
Sep-13
Oct-13
Nov-13
Dec-13
Jan-14
Feb-14
Mar-14
Apr-14
May-14
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Mar-15
Apr-15
May-15
Jun-15
Jul-15
Aug-15
Sep-15
Oct-15
Nov-15
Dec-15
Jan-16
Feb-16
NSP Diversity Sales
NSP Diversity Purchases
GRE Diversity Sales
GRE Diversity Purchases

b)

	NSP Diversity GWh				GRE Diversity GWh			
	Sales		Purchases		Sales		Purchases	
	7 x 16	7 x 8	7 x 16	7 x 8	7 x 16	7 x 8	7 x 16	7 x 8
Apr-13					69	35		
May-13					74	37		
Jun-13	58	0			72	36		
Jul-13	104	1			74	37		
Aug-13	96	0			74	37		
Sep-13	36	0			53	27		
Oct-13					71	35		
Nov-13					59	25		
Dec-13					50	2	2	1
Jan-14					20	0	24	24
Feb-14					5	0	60	34
Mar-14					31	13	31	15
Apr-14					74	20	2	2
May-14					46	16		
Jun-14	60	0			75	30		
Jul-14	93	2			78	32		
Aug-14	93	0			79	33		
Sep-14	49	0			71	30		
Oct-14					17	22		
Nov-14								
Dec-14								
Jan-15								
Feb-15								
Mar-15								
Apr-15								
May-15	40	0			98	12		
Jun-15	40	0			93	6		
Jul-15	43	0			99	6		
Aug-15	43	0			80	1		
Sep-15	42	0			95	5		
Oct-15	37	0			79	9		
Nov-15								
Dec-15								
Jan-16								
Feb-16								

c) For 2015/16, GRE Diversity deliveries are reported under NEB Permit # 387, and NSP Diversity deliveries are reported under Permit # 374 in combination with energy deliveries under the NSP 375/325 contract.

Section:	MIPUG MFR 4; MIPUG MFR 3; PUB MFR 0	**Page No.:**	pp. 4, 8 & 9 and Schedules D1 and D2; pp. 1 & 2; p.2
Topic:	Domestic Load/ExportsPCOSS14 116-08, PCOSS 14 Amended		
Subtopic:	Energy and Demand		
Issue:	DSM Add-Back to Domestic Load		

PREAMBLE TO IR (IF ANY):

MFR 1 – B.O. 116/08 Directive 19 revisions to PCOSS09 Item (d) first paragraph, last sentence: "The PUB clarified their intent in 116/08, and stated that while the costs of DSM are to be directly assigned to the export class, exports should not be deemed to receive the benefit from associated energy savings".

QUESTION:

a) Confirm that in MFR 4, Schedule B-2 (116-08) MH Domestic sales and Export sales were forecast at 22,293 GWh and 9013 GWh, respectively for 2013/14.

b) Identify the add-ons in MFR 4 schedules D-1 and D-2 that result in the 27,588 GWh (Domestic Load) and 9740 GWh (Exports) at generation for 2013/14 compared to the domestic and export sales volumes in (a). Specifically, indicate the transmission and distribution losses and the DSM add-on(s).

c) Reconcile the 25,450 GWh (Domestic) and the 5010 GWh (Exports) values in PCOSS14 and PCOSS14 Amended Schedule D1 with the 27,588 GWh and 9,740 GWh shown in MIPUG MFR 4 Schedule D1.

d) Confirm whether MH received any additional direction from the Board following Order 116/08 with respect to the treatment of DSM costs and savings in future COS studies. If confirmed, please provide MH's understanding of the Board's additional direction and whether the treatment of DSM in PCOSS14-116/08 reflects B.O.116/08 Directive #19 or this additional direction from the Board.

e) Produce a revised PCOSS14 116-08 consistent with the Board's additional direction with respect to DSM costs and savings.

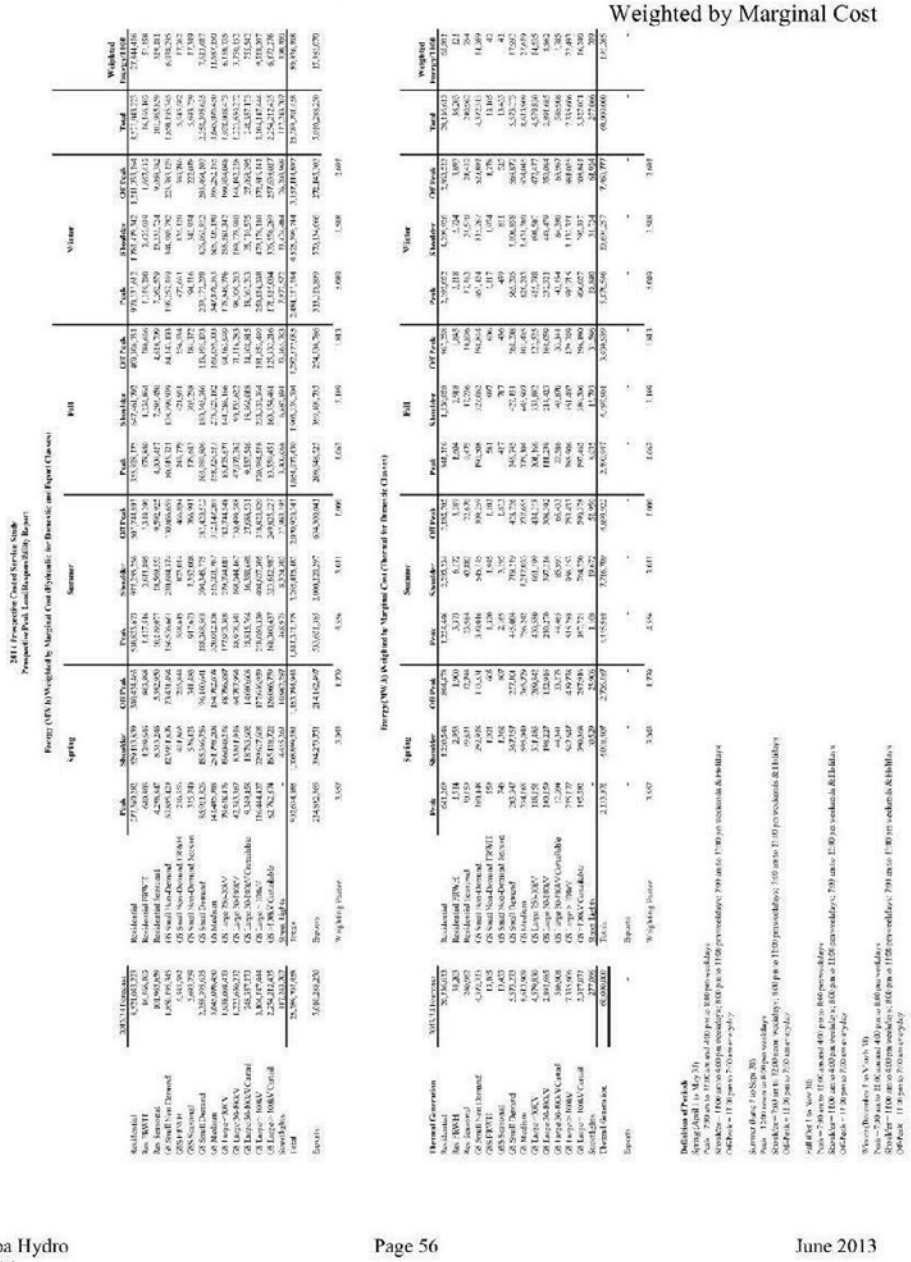
f) Explain the changes and rationale in the treatment of DSM energy savings in each of the various PCOSS(s) since PCOSS06 with respect to the calculation of the Weighted Energy allocator.

SCHEDULE D1
Seasonal Coincident Peaks (2 CP) at Generation Peak

2014 Prospective Cost of Service Study
Prospective Peak Load Responsibility Report
Seasonal Coincident Peaks (2 CP) at Generation Peak

			Winter				*SUMMER*			D14
	Forcast Total Energy @ Generation	Avg % of Yearly Energy	Estimated Seasonal Energy	Seasonal CP LF	Estimated Seasonal Demand	Avg % of Yearly Energy	Estimated Seasonal Energy	Seasonal CP LF	Estimated Seasonal Demand	2CP Estimated Demand
Residential										
Residential	8,541,179,836	63.0%	5,380,943,297	70.1%	1,767,057	37.0%	3,160,236,539	73.0%	980,320	1,373,688
Seasonal	102,206,821	43.6%	44,603,685	162.5%	6,319	56.4%	57,603,136	162.5%	8,027	7,173
Water Heating	16,204,306	49.5%	8,021,131	126.0%	1,465	50.5%	8,183,175	126.0%	1,471	1,468
Total Residential	8,659,590,963		5,433,568,112		1,774,841		3,226,022,850		989,817	1,382,329
GS Small										
Non-Demand	1,854,567,658	57.8%	1,071,940,106	73.5%	333,915	42.2%	782,627,551	69.7%	254,269	294,092
Demand	2,363,968,908	56.1%	1,326,185,557	76.9%	396,998	43.9%	1,037,782,351	78.2%	300,518	348,758
Subtotal	4,218,536,565		2,398,125,663		730,913		1,820,409,902		554,787	642,850
Seasonal	5,707,215	20.0%	1,141,443	162.5%	162	80.0%	4,565,772	162.5%	636	399
Water Heating	5,558,687	49.7%	2,763,057	106.0%	600	50.3%	2,795,630	106.0%	597	599
Total GSS	4,229,802,467		2,402,031,163		731,675		1,827,771,304		556,020	643,848
General Service - Medium	3,653,690,359	53.0%	1,936,455,890	79.0%	564,275	47.0%	1,717,234,469	76.8%	506,337	535,306
General Service - Large										
0 - 30 Kv	1,942,588,302	50.6%	982,949,681	81.6%	277,301	49.4%	959,638,621	78.8%	275,773	276,537
30 - 100 Kv	1,226,541,957	52.2%	640,254,901	92.2%	159,857	47.8%	586,287,055	105.8%	125,486	142,672
30 - 100 Kv - Curtailed Cust	248,944,081	49.2%	122,480,488	102.3%	27,561	50.8%	126,463,593	95.9%	29,862	28,712
Over 100 Kv	3,111,483,050	52.7%	1,539,751,567	96.9%	389,551	47.3%	1,471,731,483	104.8%	318,008	353,780
Over 100 Kv - Curtailed Cust	2,259,539,507	50.1%	1,132,029,293	105.1%	247,951	49.9%	1,127,510,214	104.3%	244,798	246,374
Total G.S.- Large	8,789,096,897		4,517,465,930		1,102,221		4,271,630,966		993,927	1,048,074
Street Lighting	117,520,773	57.5%	67,618,144	86.7%	17,964	42.5%	49,902,629	0.0%	-	8,982
Total - General Consumers	25,449,701,458		14,357,139,240		4,190,977		11,092,562,218		3,046,102	3,618,539
Extra Provincial	5,010,288,250	37.6%	1,883,868,382	111.6%	388,594	62.4%	3,126,419,868	89.3%	792,806	590,700
Integrated System	30,459,989,708		16,241,007,622		4,579,571		14,218,982,086		3,838,907	4,209,239

SCHEDULE D2
Prospective Peak Load Responsibility Report Energy (kWh)
Weighted by Marginal Cost



RATIONALE FOR QUESTION:

To explore the treatment of DSM costs and benefits in Manitoba Hydro cost of service methodology.

RESPONSE:

a) Confirmed

b) As requested, the following is a reconciliation of Schedule B2 and Schedules D1/D2 of PCOSS14 (Order 116/08).

	General Consumers (GWh)	**Export (GWh)**
Metered Energy (Schedule B2-116/08)	22,293	9,013
Add: Transmission Losses	2,217	821
Add: Distribution Losses	970	n/a
Add: DSM Add-on Cumulative Energy Savings	2,138	n/a
Less: On Peak Opportunity Exports (US) that do not use MH Transmission	n/a	(94)
Less: SEP	(30)	n/a
Equals: Energy at Generation for 2CP Transmission Allocator (Schedule D1 – 116/08)	27,588	9,740
Add: On Peak Opportunity Exports (US)	n/a	94
Less: Exports served by directly assigned power purchases/wind/thermal	n/a	(3,183)
Equals: Energy at Generation for Weighted Energy Allocator (Schedule D2 – 116/08)	27,588	6,651

c) As requested, the following is a reconciliation of Schedule D1 of PCOSS14 (Order 116/08) to PCOSS14 and PCOSS14-Amended.

	General Consumers (GWh)	**Export (GWh)**
Energy at Generation for 2CP Transmission Allocator (Schedule D1 – 116/08)	27,588	9,740
Exclude Adjustment: DSM Add-on Cumulative Energy Savings	(2,138)	
Add: On Peak Opportunity Exports (US)	n/a	94
Less: Total Opportunity Exports		(4,824)
Equals: Energy at Generation for 2CP Transmission Allocator (Schedule D1 PCOSS14 and PCOSS14-Amended)	25,450	5,010

Response to parts d) and e):

The only further direction that MH is aware specific to the treatment of DSM in COS flows from Order 150/08. At page 77, part d) of that Order, the PUB confirms its direction as reflected in Order 116/08 that DSM cost be assigned directly to the export class and the DSM energy savings to domestic load for generation cost saving purposes.

The version of PCOSS14 prepared reflecting Order 116/08 assigns the cost of DSM directly to the export class and the DSM energy savings to domestic customers as directed in these Orders.

f) Manitoba Hydro prepared an updated version of PCOSS06 to comply with Order 117/06. In the updated version of PCOSS06, Manitoba Hydro assigned DSM costs and associated energy savings to the export class. In the updated study as filed in PUB MFR 7, the reduced export class sales were used to calculate the weighted energy allocator.

Order 116/08 directed that DSM costs be assigned to the export class but the energy savings were to be added back to domestic load. In the updated PCOSS08 (Order 116/08) study, the domestic class energy at generation was increased by the class's cumulative

estimated reduction in energy consumption due to DSM. The MIPUG MFR 4 version of PCOSS14 (Order 116/08) has been prepared on the same basis.

Since that time, Manitoba Hydro has assigned DSM cost to those customer classes who participate in DSM in its Cost of Service Studies. DSM is undertaken to meet Manitoba load reliably and at least cost. DSM programs reduce the overall cost of the system for domestic customers by deferring generation investment as well as transmission and distribution investment. This COS methodology is the most cost causal approach as it most closely aligns the cost of the DSM programs with those classes who participate and benefit. The outcome of DSM is that it frees up energy that can be exported, while that outcome is not the driver of DSM, any revenue generated is returned to domestic customers that also serve to lower costs otherwise incurred.

Section:	Main Submission	**Page No.:**	15
Topic:	Treatment of Export Revenues and Cost		
Subtopic:	Cost Assignment to Dependable and Opportunity Export Sales		
Issue:	Fixed Costs of Hydraulic Resources for Opportunity Sales		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro states as follows:

“Opportunity sales are only made as short term surpluses allow and Manitoba Hydro does not put in place firm resources to serve these sales.”

"On the other hand, opportunity sales rely on water flows which are above dependable and are made only as short-term surpluses allow. It is true that some Manitoba Hydro facilities are designed to permit the use of flows which are above dependable levels to facilitate exports. These include additional generating capability at some Generating Stations as well as additional Transmission capacity. However, these incremental facilities are placed in service at much below average cost of Generation and Transmission facilities and are, in any event, used to serve domestic or other firm loads on a priority basis. Given the difficulty of precise identification of these facilities and their cost, and given that firm exports continue to be costed at a full share of embedded cost, it is not greatly inaccurate to assign opportunity sales only the variable costs such as imports, water rentals and thermal fuel cost."[PCOSS06]

QUESTION:

Please provide the following for each hydraulic generating station:

a) the number of generating units in each station that are required to maximize generation from dependable (minimum) flows;

b) the total number of generating units;

RATIONALE FOR QUESTION:

To determine the fixed costs of Manitoba Hydro's generating stations that serve opportunity sales.

RESPONSE:

Response to part a) and b):

The Manitoba Hydro system is planned on the basis that, subject to outages, all generating units from each generating station are available to operate in order to meet peak load conditions (i.e. maximize generation) and required reserves, whether under dependable flow conditions or during higher inflow conditions. The following table provides the number of units installed at each generating station and assumed to be available to meet load requirements under dependable flow conditions.

Generating Station	Number of Units assumed to be available to operate, subject to outages, under dependable flow conditions	Number of Units installed
Pointe du Bois	16	16
Slave Falls	8	8
Seven Sisters	6	6
McArthur Falls	8	8
Great Falls	6	6
Pine Falls	6	6
Grand Rapids	4	4
Jenpeg	6	6
Kelsey	7	7
Wuskwatim	3	3
Kettle	12	12
Long Spruce	10	10
Limestone	10	10
Laurie River I	2	2
Laurie River II	1	1

Generating Station	Number of Units assumed to be available to operate, subject to outages, under dependable flow conditions	Number of Units installed
Brandon Coal (steam)	1	1
Brandon SCCT	2	2
Selkirk NG (steam)	2	2

It should be noted that Manitoba Hydro's generation planning criteria consists of two components, both of which must be satisfied to ensure an adequate supply (Manitoba load and firm export sales). There is a capacity criterion, used to determine the minimum quantity of generation capacity required. There is also an energy criterion, used to determine the minimum quantity of energy required. Meeting only the energy criterion will leave insufficient capacity resources to meet Manitoba load during peak demand hours.

As explained in Manitoba Hydro's response to PUB/MH I-25a-c, Manitoba Hydro's system is developed based on an energy planning criteria related to dependable flow conditions and a capacity planning criteria related to peak load demands and capacity planning reserve margins. As a result, there will be surplus energy available under higher than dependable flow conditions and, subject to equipment outages, surplus capacity available during non-peak load conditions. Manitoba Hydro uses these surplus resources to generate electricity when available and when incremental costs are recovered to reduce operating costs and/or achieve opportunity export revenues.

Given that the generation and transmission capacity required to make opportunity sales is only available when firm capacity commitments (Manitoba load and firm export sales) are not at their peak, opportunity sales incur only variable costs.

Section:	Main Submission	**Page No.:**	15
Topic:	Treatment of Export Revenues and Cost		
Subtopic:	Cost Assignment to Dependable and Opportunity Export Sales		
Issue:	Fixed Costs of Hydraulic Resources for Opportunity Sales		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro states as follows:

“Opportunity sales are only made as short term surpluses allow and Manitoba Hydro does not put in place firm resources to serve these sales.”

"On the other hand, opportunity sales rely on water flows which are above dependable and are made only as short-term surpluses allow. It is true that some Manitoba Hydro facilities are designed to permit the use of flows which are above dependable levels to facilitate exports. These include additional generating capability at some Generating Stations as well as additional Transmission capacity. However, these incremental facilities are placed in service at much below average cost of Generation and Transmission facilities and are, in any event, used to serve domestic or other firm loads on a priority basis. Given the difficulty of precise identification of these facilities and their cost, and given that firm exports continue to be costed at a full share of embedded cost, it is not greatly inaccurate to assign opportunity sales only the variable costs such as imports, water rentals and thermal fuel cost."[PCOSS06]

QUESTION:

Please provide the following for each hydraulic generating station:

c) the incremental original cost and IFF12 net book value of the turbines, generating units, step-up transformers, and ancillary equipment that are surplus to dependable generation (i.e. total generating units less generating units needed for dependable flow); and

d) the total original cost and IFF12 net book value of each generating station.

RATIONALE FOR QUESTION:

To determine the fixed costs of Manitoba Hydro's generating stations that serve opportunity sales.

RESPONSE:

As indicated in Manitoba Hydro's response to PUB/MH I-28a-b, the Manitoba Hydro system is planned on the basis that all installed units will be required in order to meet peak load conditions (i.e. maximize generation) and required reserves, whether under dependable flow conditions or during higher inflow conditions. As such, there are no incremental facilities surplus to that needed under dependable conditions.

Section:	PUB/MFR 3 2004/05 PRP	**Page No.:**	
Topic:	Keeyask Capital Cost		
Subtopic:	Reduced installed Hydraulic Capacity		
Issue:	Marginal Cost/Benefit of Additional Units		

PREAMBLE TO IR (IF ANY):

In PRP 2004/05 MH provided both a 10 unit and a 5 unit generation scenario; dependable energy outputs were similar and the case for more units was not readily apparent.

QUESTION:

a) Provide adjusted capital cost estimates for Keeyask G.S. assuming 540 MW, 450 MW, and 360 MW installed capacities.

b) Provide the revised dependable energy/average energy/maximum energy output for Keeyask G.S. assuming 540 MW, 450 MW, and 360 MW installed capacities.

c) Provide the unit fixed costs (¢/kWh) for the above scenarios assuming all fixed costs flow to: 1) dependable energy and 2) average energy outputs.

RATIONALE FOR QUESTION:

To explore the unit costs of the Lower Nelson River plants above dependable flow may not provide any lower cost energy.

RESPONSE:

Response to part a) to c):

Manitoba Hydro does not have available adjusted capital cost estimates for Keeyask G.S. for 540 MW, 450 MW, and 360 MW installed capacities or revised dependable energy/average energy/maximum energy output for Keeyask G.S. assuming 540 MW, 450 MW, and 360 MW installed capacities as this information does not exist.

Manitoba Hydro also does not have the information required to calculate the unit fixed costs (¢/kWh) for the above hypothetical scenarios identified as the information does not exist. The PUB recommended the Keeyask G.S. at the NFAT as proposed and Manitoba Hydro did not perform analysis assuming different installed capacities.

Section:	MIPUG MFR 3; MIPUG MFR 4	**Page No.:**	1 and 2; 1 and Schedule D1
Topic:	Transmission Cost Allocation		
Subtopic:	Seasonal 2CP at Generation		
Issue:	Should 1CP be Considered		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Confirm that MH's seasonal 2CP analysis reflects 12 years of load research from 2004 to 2012. If not, please indicate what was included in the analysis and explain.

b) Provide the 2CP 50 winter/50 summer peak load research data from 2004 to date. Please provide the data in electronic format.

c) Provide a tabular history of MH's seasonal 2CP analysis as carried out in PCOSS04 to PCOSS15.

d) Explain the rationale for using 2CP as opposed to 1CP to classify and allocate the demand portion of the transmission function. In responding, please comment on whether as a result of domestic load peaking in the winter it is winter peak that drives investment in new generation for Manitoba demand, while the summer peak from exports drives investment in plant that is now functionalized as generation (HVDC, Dorsey, Riel) or is allocated according to weighted energy (U.S. interties).

e) Explain any changes and the rationale in the treatment of DSM demand savings in each of the various PCOSS(s) since PCOSS06, specifically related to the calculation of the 2CP allocator.

f) Explain any other changes in methodology in calculating the 2CP from PCOSS08 to PCOSS14.

Schedule D-1
Seasonal Demand

	Winter (MW)		Summer (MW)		2CP (MW)	
Residential	1775	(42%)	990	(33%)	1382	(38%)
GSS Non-demand	334	(8%)	254	(8%)	294	(8%)
GSS Demand	397	(9%)	301	(10%)	319	(10%)
GSM	564	(13%)	506	(17%)	535	(15%)
GSL <30	277	(7%)	276	(9%)	277	(8%)
GSL 30-100	187	(4%)	155	(5%)	171	(5%)
GSL >100	638	(15%)	536	(18%)	600	(16%)
Total	4191	(98%)	3046	(100%)	3619	(100%)

RATIONALE FOR QUESTION:

To determine whether the 2CP allocator is still appropriate.

RESPONSE:

a) Not confirmed. The calculation of the 2CP Demand used in PCOSS14-Amended was based on one year of Load Research. Please see the response to PUB/MH I-5.

b) As discussed in Manitoba Hydro's response to PUB/MH I-5 the definition of peak was modified in 2011/12, and load research on this basis of this revised definition is not available for prior periods. The 2011/12 Load Research at Generation Peak, which was used to calculate 2CP demand in PCOSS14, has been provided in Excel format with materials filed on March 11, 2016.

c)

Tabular History of Seasonal Coincident Peak (2CP) at Generation Peak (kW)

	PCOSS04	PCOSS06 Recommended Methodology	PCOSS06 Response Order 117/06	PCOSS08 Response Order 117/06	PCOSS08 Response 116/08	PCOSS10	PCOSS11	PCOSS13 Methodology Changes	PCOSS14	PCOSS14 Amended
Residential										
Residential	1,221,988	1,183,282	1,183,282	1,009,167	1,087,682	1,098,991	1,112,039	1,229,552	1,373,688	1,373,688
Seasonal	4,222	4,987	4,987	5,066	5,066	5,923	6,731	6,675	7,173	7,173
Water Heating	2,505	1,714	1,714	1,820	1,820	1,699	1,723	1,537	1,468	1,468
Total Residential	1,228,714	1,189,983	1,189,983	1,016,053	1,094,568	1,106,614	1,120,492	1,237,764	1,382,329	1,382,329
GS Small										
Non-Demand	287,458	270,086	270,086	240,502	270,797	254,973	274,424	280,539	294,092	294,092
Demand	296,693	281,874	281,874	327,714	359,799	314,507	304,279	319,429	348,758	348,758
Subtotal	584,151	551,960	551,960	568,217	630,597	569,480	578,703	599,968	642,850	642,850
Seasonal	350	345	345	343	343	343	384	387	399	399
Water Heating	1,209	788	788	766	766	683	672	624	599	599
Total GSS	585,710	553,093	553,093	569,326	631,706	570,506	579,760	600,979	643,848	643,848
General Service - Medium	525,400	496,198	496,198	471,617	525,407	474,906	482,208	497,553	535,306	535,306
General Service - Large										
0 - 30 Kv	246,916	226,834	226,834	253,490	277,420	233,451	239,855	267,122	276,537	276,537
30 - 100 Kv	86,555	69,262	69,262	105,521	110,686	124,395	84,160	108,172	142,672	142,672
30 - 100 Kv - Curtailed Cust	n/a	27,644	27,644	26,439	27,695	26,439	27,221	28,240	28,712	28,712
Over 100 Kv	282,795	330,382	330,382	321,454	345,855	350,078	320,728	351,951	353,780	353,780
Over 100 Kv - Curtailed Cust	273,392	302,856	302,856	322,271	343,170	344,566	335,657	249,217	246,374	246,374
Total G.S.- Large	889,657	956,978	956,978	1,029,175	1,104,825	1,078,928	1,007,621	1,004,702	1,048,074	1,048,074
Street Lighting	8,958	8,680	8,680	8,627	10,532	8,963	9,134	8,939	8,982	8,982
Total - General Consumers	3,238,439	3,204,932	3,204,932	3,094,798	3,367,038	3,239,917	3,199,215	3,349,937	3,618,539	3,618,539
Extra Provincial	n/a	765,045	1,396,832	1,053,208	1,053,208	1,104,559	989,941	507,724	590,700	590,700
	3,238,439	3,969,977	4,601,764	4,148,006	4,420,246	4,344,476	4,189,156	3,857,661	4,209,239	4,209,239

d) Manitoba Hydro does not agree with the premise of the question that Manitoba winter peak capacity requirements drive capacity-related generation investment while exports drive energy-related generation requirements. The driver of all resources is the need to provide reliable power for Manitobans at lowest long term cost. New generation for Manitoba is put in place to most economically serve both domestic peak load as well as domestic energy needs throughout the year.

To the extent that capacity or energy surplus is not temporarily needed to serve Manitoba load, it may be exported. On the basis that resources are also available to serve export loads, within cost of service, Manitoba Hydro assigns or allocates some of the fixed cost of generation and transmission resources to dependable exports on a basis equivalent to Manitoba load.

To allocate transmission cost, for other than U.S. interties, Manitoba Hydro utilizes a 2CP allocator. This allocator recognizes the winter peak load of domestic customers as well as a comparatively high summer peak of export sales. Surplus energy is exported through both the networked transmission system within the province and the interconnections. If the surplus energy exported could be streamed only through the HVDC and interconnections, there would be no basis for allocating a share of the cost of any other transmission infrastructure to them. This treatment puts domestic and dependable exports on equal footing recognizing each distinct peak load and a reasonable method to allocate ac transmission network infrastructure costs between domestic customers and dependable exports.

e) In PCOSS08 (Order 116/08), DSM energy savings were to be added back to domestic load for generation cost-sharing purposes. In that study, the 2CP allocator was modified to add back to each season the estimated reduction in seasonal demand due to DSM. The result of this adjustment can be seen in part c) by comparing the class 2CP demands calculated in PCOSS08 (Order 117/06) to those in PCOSS08 (Order 116/08).

f) The methodology used to calculate the 2CP allocator has not been changed between PCOSS08 and PCOSS14, excluding the treatment of DSM as discussed in e) in PCOSS08 (Order 116/08). The general approach to export cost assignment used in the study will determine the amount, if any, that opportunity export energy is included when calculating the 2CP allocator, but does not change the methodology used to calculate the 2CP demand.

Section:	Schedule D-2 Schedule D-1	**Page No.:**	14 of 18 13 of 18
Topic:	Domestic & Export Load Profiles		
Subtopic:	Average Monthly Demand		
Issue:	Marginal Cost Weighting of Energy/Demand		

PREAMBLE TO IR (IF ANY):

Fixed costs are driven in large part by installed generation capacity. The use of winter peak demand only could alter the cost allocation to domestic classes.

QUESTION:

a) Confirm that the attached table drawn from Schedule D-2 illustrates the 2013/14 average monthly energy and average monthly demand load for each of 12 time periods. If not, please explain.

b) Confirm that class monthly average demands (MW) vary as follows:

	Range	**Annual Average**	**% Range**
Residential	514 to 1479	(973)	50-150
GSS Non-demand	133 to 298	(211)	60-140
GSS Demand	186 to 365	(269)	65-130
GSM	320 to 529	(416)	80-130
GSL <30	188 to 268	(221)	85-120
GSL 30-100	162 to 178	(168)	95-105
GSL >100	566 to 651	(611)	93-108

c) Indicate the domestic load contributions to demand peak for:

Class	Class/Total	%
Residential	1479/3787	39%
GSS Non-demand	298/3787	8%
GSS Demand	365/3287	10%
GSM	529/3787	14%
GSL <30	268/3787	7%
GSL 30-100	178/3787	5%
GSL >100	651/3787	17%

PCOSS14 Schedule D2 with Average Demand
2013/14

(kWh)	Spring (Apr-May)						Summer (Jun-Sep)					
	Peak Energy	Avg Dmd	Shoulder Energy	Avg Dmd	Off-Peak Energy	Avg Dmd	Peak Energy	Avg Dmd	Shoulder Energy	Avg Dmd	Off-Peak Energy	Avg Dmd
# of hours	352	MW	624	MW	488	MW	672	MW	1280	MW	976	MW
Residential	271,360,282	771	529,183,839	848	340,424,463	698	530,833,673	790	971,255,256	759	501,744,893	514
ResidentialFRWH	640,806	2	1,249,646	2	803,898	2	1,427,516	2	2,611,895	2	1,349,290	1
ResidentialSeasonal	4,298,847	12	8,383,246	13	5,392,950	11	10,149,077	15	18,569,553	15	9,592,925	10
GSSmallNon-Demand	67,895,429	193	123,951,876	199	73,431,494	150	156,576,661	233	230,684,374	180	130,866,659	134
GSSmallNon-DemandFRWH	236,556	1	431,863	1	255,844	1	558,619	1	823,014	1	466,894	0
GSSmallNon-DemandSeason	315,740	1	576,424	1	341,485	1	917,673	1	1,352,008	1	766,991	1
GSSmallDemand	85,921,826	244	155,366,756	249	96,100,641	197	188,308,568	280	304,345,775	238	181,420,512	186
GSMedium	141,405,988	402	251,798,208	404	154,762,674	317	320,012,836	476	515,001,767	402	312,147,269	320
GSLarge750-30kV	79,618,476	226	136,040,218	218	88,796,887	182	177,973,309	265	279,794,081	219	183,744,548	188
GSLarge30-100kV	42,383,367	120	83,881,916	134	64,707,994	133	88,978,341	132	168,044,467	131	130,499,588	134
GSLarge30-100kVCurtailable	9,349,458	27	18,763,602	30	14,080,608	29	18,815,764	28	36,388,698	28	27,688,531	28
GSLarge>100kV	116,444,437	331	229,627,603	368	177,616,959	364	218,050,330	324	404,607,305	316	318,823,820	327
GS>100kVCurtailable	82,762,874	235	165,188,722	265	126,066,759	258	168,300,437	250	323,612,987	253	249,825,227	256
StreetLights-	4,455,261	13	10,962,287	18	468,975	1	8,324,303	12	21,983,195	17	3,400,068	3
Totals	902,634,085	2,564	1,708,899,181	2,739	1,153,744,944	2,364	1,881,371,779	2,800	3,265,415,483	2,551	2,070,920,341	2,122
Exports	214,892,366	610	394,273,751	632	214,162,497	439	533,651,385	794	1,000,120,297	781	634,300,041	650
Weighting Factor	3.657		3.043		1.739		4.556		3.011		1.000	

	Fall (Oct-Nov)						Winter (Dec-Mar)								
	Peak Energy	Avg Dmd	Shoulder Energy	Avg Dmd	Off-Peak Energy	Avg Dmd	Peak Energy	Avg Dmd	Shoulder Energy	Avg Dmd	Off-Peak Energy	Avg Dmd	Total Energy	Avg Dmd	Weighted Energy/1000
# of hours	328	MW	648	MW	488	MW	656	MW	1280	MW	968	MW	8760	MW	
Residential	355,928,175	1,085	647,461,792	999	409,306,731	839	970,331,612	1,479	1,781,479,342	1,392	1,211,733,164	1,252	8,521,043,223	973	27,844,416
ResidentialFRWH	678,840	2	1,234,864	2	780,646	2	1,319,230	2	2,422,039	2	1,647,432	2	16,166,103	2	51,158
ResidentialSeasonal	4,009,417	12	7,293,450	11	4,610,709	9	7,262,579	11	13,333,724	10	9,069,382	9	101,965,859	12	319,181
GSSmallNon-Demand	80,615,721	246	138,399,939	214	84,143,103	172	195,257,169	298	344,989,792	270	223,383,129	231	1,850,195,345	211	6,038,295
GSSmallNon-DemandFRWH	245,779	1	421,951	1	256,534	1	472,661	1	835,120	1	540,746	1	5,545,582	1	17,762
GSSmallNon-DemandSeason	176,643	1	303,258	0	184,372	0	194,116	0	342,974	0	222,078	0	5,693,759	1	17,349
GSSmallDemand	103,989,806	317	180,745,346	279	113,495,193	233	239,173,298	365	426,063,812	333	283,464,103	293	2,358,395,635	269	7,613,687
GSMedium	158,729,513	484	273,323,182	422	169,859,303	348	347,078,363	529	605,705,190	473	395,252,155	408	3,645,076,450	416	11,687,150
GSLarge750-30kV	85,125,671	260	141,286,166	218	94,163,949	193	175,949,776	268	295,581,342	231	199,934,048	207	1,938,008,473	221	6,150,735
GSLarge30-100kV	47,072,282	144	90,735,622	140	71,116,283	146	98,309,203	150	189,778,980	148	148,142,228	153	1,223,650,272	140	3,750,152
GSLarge30-100kVCurtailable	9,557,546	29	18,564,018	29	14,108,815	29	18,261,263	28	35,710,575	28	27,068,295	28	248,357,173	28	755,542
GSLarge>100kV	120,984,518	369	233,332,364	360	181,853,449	373	250,814,338	382	479,176,180	374	372,816,141	385	3,104,147,444	354	9,518,307
GS>100kVCurtailable	83,559,451	255	163,554,461	252	125,332,216	257	171,815,004	262	336,556,269	263	257,638,027	266	2,254,212,435	257	6,872,276
StreetLights-	6,682,891	20	13,365,783	21	7,972,572	16	13,424,404	20	26,203,969	20	117,243,707	121	300,100	0	
Totals	1,054,073,430	3,214	1,903,339,304	2,937	1,282,577,085	2,628	2,484,211,184	3,787	4,525,399,744	3,535	3,157,114,897	3,261	25,389,701,458	2,898	80,936,108
Exports	209,648,525	639	399,109,735	616	254,530,786	522	313,318,899	478	570,134,666	445	272,145,303	281	5,010,288,250	572	15,381,070
Weighting Factor	4.063		3.189		1.813		5.049		3.588		2.691				

RATIONALE FOR QUESTION:

To better understand the basis of allocation of hydraulic generation and HVDC transmission costs to energy and demand.

RESPONSE:

Response to parts a) to c):

Part a) is not confirmed. In Schedule D-2 the energy used in the weighted energy allocator is distributed between twelve time periods (Spring Peak/Off-Peak/Shoulder, Summer Peak/Off-Peak/Shoulder, Fall Peak/Off-Peak/Shoulder and Winter Peak/Off-Peak/Shoulder), which do not correspond to months. Manitoba Hydro has recreated the calculation updating the hours per period to match Manitoba Hydro's assumption and correcting the streetlighting energy to match Schedule D-2 (see Tables 1 and 2 below).

Tables 3 and 4 below provide the updated comparison of major domestic classes based on the revised data in Tables 1 and 2.

Manitoba Hydro is unclear on what is being requested in part c), but has provided updated class shares of average peak in each of the twelve periods consistent with the calculation in the table cited in the Information Request.

Table 1: Class Energy kWh (Schedule D2-Amended)

	Spring			Summer			Fall			Winter			
	Peak	**Shoulder**	**Off Peak**	**Peak**	**Shoulder**	**Off Peak**	**Peak**	**Shoulder**	**Off Peak**	**Peak**	**Shoulder**	**Off Peak**	**Total**
Residential	272,001,550	530,434,386	341,228,942	532,088,120	973,550,491	502,930,598	356,769,291	648,991,849	410,273,989	972,624,664	1,785,689,267	1,214,596,687	8,541,179,836
Residential FRWH	642,320	1,252,599	805,798	1,430,889	2,618,068	1,352,479	680,444	1,237,783	782,491	1,322,348	2,427,763	1,651,325	16,204,306
Residential Seasonal	4,309,005	8,403,057	5,405,695	10,173,061	18,613,436	9,615,594	4,018,892	7,310,685	4,621,605	7,279,742	13,365,234	9,090,814	102,206,821
GS Small Non-Demand	68,055,877	124,244,795	73,605,024	156,946,677	231,229,519	131,175,918	80,806,229	138,727,001	84,341,946	195,718,593	345,805,059	223,911,020	1,854,567,658
GS Small Non-Demand FRWH	237,115	432,884	256,449	559,940	824,959	467,997	246,360	422,948	257,140	473,778	837,094	542,024	5,558,687
GS Small Non-Demand Seasonal	316,486	577,786	342,292	919,842	1,355,203	768,803	177,060	303,974	184,807	194,575	343,784	222,603	5,707,215
GS Small Demand	86,124,873	155,733,913	96,327,743	188,753,572	305,064,993	181,849,238	104,235,551	181,172,476	113,763,401	239,738,503	427,070,670	284,133,975	2,363,968,908
GS Medium	141,740,153	252,393,249	155,128,403	320,769,079	516,218,800	312,884,924	159,104,617	273,969,089	170,260,709	347,898,566	607,136,570	396,186,201	3,653,690,359
GS Large 750-30kV	79,806,628	136,361,704	89,006,729	178,393,889	280,455,280	184,178,767	85,326,837	141,620,048	94,386,474	176,365,574	296,279,849	200,406,525	1,942,588,302
GS Large 30-100kV	51,855,078	102,888,086	78,974,793	108,048,841	204,916,274	158,561,943	56,763,653	109,557,933	85,426,498	116,845,941	226,022,424	175,624,574	1,475,486,038
GS Large > 100kV	199,678,070	395,749,340	304,401,373	387,263,777	729,941,195	569,992,857	205,027,340	397,824,734	307,911,595	423,628,084	817,660,158	631,944,034	5,371,022,556
Street Lights	-	4,465,789	10,988,192	470,083	8,343,975	22,035,145	3,408,102	6,698,684	13,397,368	7,991,413	13,456,129	26,265,893	117,520,773
Totals	904,767,156	1,712,937,588	1,156,471,432	1,885,817,767	3,273,132,192	2,075,814,263	1,056,564,378	1,907,837,205	1,285,608,023	2,490,081,780	4,536,094,001	3,164,575,673	25,449,701,458
Exports	214,892,366	394,273,751	214,162,497	533,651,385	1,000,120,297	634,300,041	209,648,525	399,109,735	254,530,786	313,318,899	570,134,666	272,145,303	5,010,288,250

Table 2: Class Average Period Demand MW

	Spring			Summer			Fall			Winter			
	Peak	**Shoulder**	**Off Peak**	**Peak**	**Shoulder**	**Off Peak**	**Peak**	**Shoulder**	**Off Peak**	**Peak**	**Shoulder**	**Off Peak**	**Total**
Hours in Period	**328**	**648**	**488**	**671**	**1,281**	**976**	**339**	**637**	**488**	**661**	**1,279**	**970**	**8,766**
Residential	829	819	699	793	760	515	1,052	1,019	841	1,471	1,396	1,252	974
Residential FRWH	2	2	2	2	2	1	2	2	2	2	2	2	2
Residential Seasonal	13	13	11	15	15	10	12	11	9	11	10	9	12
GS Small Non-Demand	207	192	151	234	181	134	238	218	173	296	270	231	212
GS Small Non-Demand FRWH	1	1	1	1	1	0	1	1	1	1	1	1	1
GS Small Non-Demand Seasonal	1	1	1	1	1	1	1	0	0	0	0	0	1
GS Small Demand	263	240	197	281	238	186	307	284	233	363	334	293	270
GS Medium	432	389	318	478	403	321	469	430	349	526	475	408	417
GS Large 750-30kV	243	210	182	266	219	189	252	222	193	267	232	207	222
GS Large 30-100kV	158	159	162	161	160	162	167	172	175	177	177	181	168
GS Large > 100kV	609	611	624	577	570	584	605	625	631	641	639	651	613
Street Lights	-	7	23	1	7	23	10	11	27	12	11	27	13
Totals	2,758	2,643	2,370	2,810	2,555	2,127	3,117	2,995	2,634	3,767	3,547	3,262	2,903
Exports	655	608	439	795	781	650	618	627	522	474	446	281	572

Table 3: Major Class Average Period Demand MW

	Spring			Summer			Fall			Winter			
	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Total
Residential	829	819	699	793	760	515	1,052	1,019	841	1,471	1,396	1,252	974
GS Small Non-Demand	207	192	151	234	181	134	238	218	173	296	270	231	212
GS Small Demand	263	240	197	281	238	186	307	284	233	363	334	293	270
GS Medium	432	389	318	478	403	321	469	430	349	526	475	408	417
GS Large 750-30kV	243	210	182	266	219	189	252	222	193	267	232	207	222
GS Large 30-100kV	158	159	162	161	160	162	167	172	175	177	177	181	168
GS Large > 100kV	609	611	624	577	570	584	605	625	631	641	639	651	613
Street Lights	-	7	23	1	7	23	10	11	27	12	11	27	13
Totals	2,742	2,627	2,356	2,791	2,537	2,114	3,102	2,980	2,622	3,753	3,533	3,251	2,888

Table 4: Comparison of Major Class Average Period Demand MW

	Min	Max	Average	Min/Avg	Max Avg
Residential	515	1,471	954	54%	154%
GS Small Non-Demand	134	296	210	64%	141%
GS Small Demand	186	363	268	69%	135%
GS Medium	318	526	417	76%	126%
GS Large 750-30kV	182	267	224	82%	119%
GS Large 30-100kV	158	181	168	94%	108%
GS Large > 100kV	570	651	614	93%	106%
Street Lights	-	27	13	0%	210%

Table 5: Class Shares of Average Period Demand

	Spring			Summer			Fall			Winter			
	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Peak	Shoulder	Off Peak	Total
Residential	30%	31%	30%	28%	30%	24%	34%	34%	32%	39%	40%	39%	34%
GS Small Non-Demand	8%	7%	6%	8%	7%	6%	8%	7%	7%	8%	8%	7%	7%
GS Small Demand	10%	9%	8%	10%	9%	9%	10%	10%	9%	10%	9%	9%	9%
GS Medium	16%	15%	13%	17%	16%	15%	15%	14%	13%	14%	13%	13%	14%
GS Large 750-30kV	9%	8%	8%	10%	9%	9%	8%	7%	7%	7%	7%	6%	8%
GS Large 30-100kV	6%	6%	7%	6%	6%	8%	5%	6%	7%	5%	5%	6%	6%
GS Large > 100kV	22%	23%	26%	21%	22%	28%	19%	21%	24%	17%	18%	20%	21%
Street Lights	0%	0%	1%	0%	0%	1%	0%	0%	1%	0%	0%	1%	0%
Totals	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Section:	Main Submission	**Page No.:**	20
Topic:	Generation and Transmission		
Subtopic:	Weighted Energy Generation Allocator		
Issue:	Weighting of Energy Allocator for market prices		

PREAMBLE TO IR (IF ANY):

QUESTION:

Please explain why the market price of power in extraprovincial jurisdictions is a factor in allocating generation costs to domestic customers classes.

RATIONALE FOR QUESTION:

To understand why the energy allocator is weighted for the market price of power.

RESPONSE:

The market price of power in MISO is used as a proxy for the marginal cost of energy. Manitoba Hydro elected to move to a generation allocation approach on the basis of marginal costs as it viewed it theoretically superior in terms of depicting cost causation. The methodology places a heavier emphasis on energy as a valid cost driver of its hydraulic utility and also reflects the influence of a significant energy market in which Manitoba Hydro participates. Consumption decisions by customers have an important effect on rates charged and particularly given those decisions impact Manitoba Hydro's opportunity cost which is often valued by the export market. It relates the cost to serve each customer class to the market value of generation (SEP prices a proxy for that short-run value); in essence the weighted energy methodology is comparable with how generation costs flow through to customers in jurisdictions with an open wholesale market. And effectively those who use more costly energy at peak periods are allocated proportionately a higher share of generation cost, a measure of fairness and which aids in the achievement of Manitoba Hydro's efficiency ratemaking objective.

Please also see Manitoba Hydro's response to PUB/MH I-42c.

Section:	PUB MFR 16; PUB MFR 18	**Page No.:**	10 of 220
Topic:	Service Extension Policy		
Subtopic:	Revenue Tests		
Issue:	Different Extension Policies for Different Classes		

PREAMBLE TO IR (IF ANY):

2015/16 GRA Coalition/MH I-34 states that: "Manitoba Hydro obtains contributions from customers in the event that the cost of extending service or the cost of accommodating a load increase exceeds either the specified investment allowance (in the case of residential customers) or the amount of investment allowance as determined by a revenue test (in the case of General Service customers served at voltages less than 30 kV). General Service customers requiring service at voltages greater than 30 kV, or any new General Service load greater than 5 MW, contribute to the full cost of the dedicated service extension facilities and capacity additions to the common integrated system, if required."

Manitoba's Climate Change and Green Economy Action Plan states: "All natural gas expansion considerations must be evaluated against green heating options (ex: geothermal, biomass, solar) on a level playing field including comparison of public infrastructure investment and value of carbon reduction. The Public Utilities Board will be directed to consider this comparison in its approval process."

QUESTION:

a) Please provide the residential customer specified investment allowance and clarify whether this is for individual residences, residential developments, or both.

b) Please compare and contrast the General Service <30 kV revenue test (which is three times annual forecasted revenue according to PUB MFR 18) with the feasibility test approved by the PUB for gas service extensions.

c) Please explain why MH does not invest in dedicated facilities to extend service to customers served at voltages greater than 30 kV or loads greater than 5 MW.

d) Please indicate how MH plans to incorporate the Province's intentions as stated in its Climate Change and Green Economy Action Plan with respect to the electric service extension policy and the gas feasibility test.

RATIONALE FOR QUESTION:

To understand the Service Extension Policy and its implications on costs incurred by customers.

RESPONSE:

a) Investment allowances for a single family residential customer, inside and outside of a residential development are the same. The applicable allowance is the lesser of the cost of an overhead distribution system, or the all electric heated home maximum allowance of $4,000, standard heated home maximum allowance of $1,600 or seasonal home maximum allowance of $800.

For example, if the cost of an overhead distribution system to supply power to a residential customer with electric heat is $5,000, then the customer would receive the maximum allowance of $4,000, thereby paying $1,000 for the service. However if the cost of overhead distribution for the same customer was $2,000, then the applicable allowance would be $2,000 and the customer would not be required to make any contribution.

b) Electric service extensions for General Service customers served at voltages < 30 kV are subject to revenue testing, with regard to specific limitations. Please see the response to COALITION/MH I-82a for information on the applicable limitations.

A revenue allowance is determined by calculating three times the incremental annual gross revenues (at current approved rates) to be obtained from the new customer. This amount of revenue allowance would be applied against the capital cost of constructing the required electrical facilities. Any costs in excess of the amount of the revenue allowance would be recovered from the customer by way of a contribution.

Natural gas service extensions are evaluated by the application of a 30-year net present value test. The test assesses the incremental costs of connecting the new customer with

the incremental gross revenues forecast for that customer, at current approved base rates. The costs of connection include the capital cost of new mains, service lines and meters required to serve the customer, plus a proportionate cost share of any upstream system reinforcements that may be required in order to serve the new customer load. The costs also include operating and maintenance costs, gas supply costs (at current approved rates), depreciation, municipal property taxes, corporate capital taxes and return on investment. The analysis calculates the net present value of the service extension assuming a 30 year period. The customer is responsible to provide a contribution, if needed, to achieve a NPV of at least zero and a revenue-to-cost ratio of 1.0 by the end of the fifth year of service.

c) By definition, dedicated facilities are those assets which are constructed for a single customer's exclusive use. This is in contrast to shared facilities, which are facilities that are available to serve other customers either at the time of the service extension, or in the future. Generally, Manitoba Hydro does not invest in dedicated facilities to exclusively serve one customer.

   General Service customers requiring service at voltages greater than 30 kV or any new General Service load greater than 5 MW are responsible for the cost of dedicated facilities and are responsible for the cost of system upgrades or capacity increases to the Corporation's common integrated system on the supply side of the interconnection to the integrated system, unless otherwise approved by Manitoba Hydro's Executive Committee.

   This policy is, in part, reflective of the concern that the addition of very large energy intensive loads may pose significant costs on the utility system that would impact the overall cost of providing service to all customers.

d) As per confirmation from PUB counsel on April 12, 2016, a response to this Information Request is not required.

Section:	PUB MFR 16	**Page No.:**	
Topic:	Rate Design		
Subtopic:	Basic Charges, Demand Charges, and Energy Charges		
Issue:	Recovery of Revenue Requirement through different rates		

PREAMBLE TO IR (IF ANY):

Order 26/16 states that the PUB intends to examine the components of the basic monthly charge, and the split between energy charges and demand charges.

QUESTION:

a) Please update PUB/MH I-146d from the 2012/13 & 2013/14 GRA (pdf p. 40 of 220) regarding MH's intentions at that time with respect to further rate increases being applied only to energy charges, in light of MH's 2014/15 & 2015/16 GRA across-the-board rate increase.

b) Please provide the status of the amalgamation of the General Service Small (demand Billed) and General Service Medium customer classes.

c) Please provide a table showing the 2013/14 approved Basic Charges, PCOSS14 Amended allocated Customer costs, and the Customer revenue to cost ratios for each class and sub-class with a Basic Charge.

d) Please provide a table showing the 2013/14 approved Demand rates, PCOSS14 Amended allocated Demand costs, and the Demand revenue to cost ratios for each class and sub-class.

e) Please provide a table showing the 2013/14 approved Energy rates, PCOSS14 Amended allocated Energy costs, and the Energy revenue to cost ratios for each class and sub-class (including Residential).

f) Please provide the current basic (monthly) charges for customers served in the following cities: Vancouver, Edmonton, Calgary, Regina, Winnipeg, Toronto, Ottawa, Montreal, Saint John, Charlottetown, Halifax, and St. John's.

g) Please update the analysis in PUB/MH I-181(a) from the 2010/11 GRA (comparing the General Service Medium and General Service Large <30 kV and 30 kV-100 kV Demand Charges, pdf. p. 151 of 220) with the PCOSS14 Amended allocations and 2013/14 approved rates.

h) Please update the tables in RCM/TREE/MH I-7(a) (pdf p. 184 and 185 of 220) with the approved rates to date.

RATIONALE FOR QUESTION:

To understand the interrelationship between Basic, Demand, and Energy Charges with respect to cost recovery and MH's intentions in respect of increases or decreases to each charge.

RESPONSE:

a) As noted in the response to PUB/MH I-146d from the 2012/13 & 2013/14 GRA, Manitoba Hydro had previously pursued a practice of increasing the energy charge component of rates for demand-billed customer classes in order to increase the recovery of revenue by way of energy charges instead of demand charges.

   However, for interim rates effective September 1, 2012, Manitoba Hydro received direction through PUB legal counsel to apply the revenue increase across all demand and energy rate components for all of Manitoba Hydro's customer classes, instead of applying the increase to only the energy component of rates. Manitoba Hydro has since interpreted this direction to apply rate increases across all rate components for each customer class.

b) The rate components for General Service Small (Demand) and General Service Medium rate classes have been, to a large extent, harmonized. The demand charges, energy charges, and size of energy blocks are the same for both customer classes. At this time, the main distinction between these rate schedules lies in the level of the Basic Charge. The Basic Charges, approved in Order 77/15, are $28.92 for General Service Small (Demand – Three Phase) customers and $30.52 for General Service Medium customers.

Response to parts c) to e):

The following schedule compares the allocated Customer, Demand and Energy costs in PCOSS14-Amended to class revenues collected through basic monthly charges, and demand and energy rates. For classes whose rate structure does not include a BMC, the Customer costs have been added to Demand costs in order to calculate an RCC for each billing determinant. Demand costs have been included in Energy costs for classes without a Demand charge.

Since the May 2013 rates came into effect part way through the 2013/14 fiscal year, the revenues shown in PCOSS14-Amended are based on one month at September 2012 rates (Order 117/12) and eleven months at the May 2013 rates (Order 43/13). Please see Manitoba Hydro's response to Coalition/MH-I-1 for a schedule of the approved rates corresponding to PCOSS14-Amended.

		CUSTOMER			DEMAND			ENERGY		
Class	Total Revenue	Revenue ($000)	Cost ($000)	Ratio	Revenue ($000)	Cost ($000)	Ratio	Revenue ($000)	Cost ($000)	Ratio
Residential	588,630	43,708	120,783	36.2%	-	*	n/a	544,922	469,251	116.1%
GS Small - Non Demand	135,035	14,064	24,054	58.5%	-	*	n/a	120,970	100,394	120.5%
GS Small - Demand	136,080	3,595	8,173	44.0%	20,579	39,210	52.5%	111,906	82,469	135.7%
General Service - Medium	186,797	669	7,148	9.4%	63,602	55,956	113.7%	122,526	124,849	98.1%
General Service - Large <30kV	84,956	-	**	n/a	30,028	27,772	108.1%	54,928	65,877	83.4%
General Service - Large 30-100kV	57,808	-	**	n/a	18,315	11,515	159.0%	39,493	46,290	85.3%
General Service - Large >100kV	189,258	-	**	n/a	47,490	22,000	215.9%	141,768	170,023	83.4%

*Costs are included in Energy Costs
**Costs are included in Demand Costs

f) The following table provides the current basic (monthly) charges and/or the fixed charges for the cities requested. To calculate the monthly charge for utilities with a per day charge, an average of 30.4 days was used. For cities with more than one fixed charge that are served by a deregulated utility in a retail access jurisdiction, the charges that were included are listed below:

Where applicable:
Edmonton (Administration Charge, Distribution Customer Charge)
Calgary (Administration Fee, Distribution Service & Facilities Charge)
Toronto (Service Charge, Standard Supply Service Administrative Charge, Rate Riders)
Ottawa (Delivery Fixed & Other Charges, Smart Meter Entity Charge)

	Monthly\Fixed Charge				
		General Service*			
	Residential	**Small Non - Demand**	**Medium**	**Large < 30 kV**	**Large > 100 kV**
Vancouver	$5.36	$6.86	$6.86	$6.86	$0.00
Edmonton	$22.47	$14.64	N/A	N/A	N/A
Calgary	$19.96	$36.58	$168.41	$489.13	$602.84
Regina	$20.22	$27.62	$51.40	$5,491.00	$6,757.00
Winnipeg	$7.57	$20.51	$30.52	$0.00	$0.00
Toronto	$24.06	$40.28	$69.47	$872.95	$3,856.74
Ottawa	$14.07	$18.02	$200.00	$15,231.32	$15,231.32
Montreal	$12.19	$12.33	$0.00	$0.00	$0.00
Saint John	$16.01	$16.49	$16.49	$0.00	N/A
Charlottetown	$24.57	$24.57	$0.00	$0.00	$0.00
Halifax	$10.83	$12.65	$0.00	$0.00	$0.00
St. John's	$15.70	$21.93	$50.08	$85.13	$85.13

* The General Service sub-classes shown are representative of the sub-classes reported in Manitoba Hydro's Survey of Canadian Electricity Bills.

N/A - EPCOR (Edmonton) and Saint John Energy (Saint John) did not provide information for the levels of consumption requested.

g) Manitoba Hydro does not have an updated analysis readily available and the updated analysis would not be completed within the time frame available for this review.

h) The information previously provided in the response to RCM/TREE/MH I-7(a) from the 2009/10 & 2010/11 GRA were based on the Cost of Service Study prepared in 2003. Manitoba Hydro is of the view that it is more relevant to base the comparison of allocated embedded costs from PCOSS14-Amended and the PUB approved energy and demand rates in effect as of May 1, 2013.

Please see the following table.

General Service Demand / Energy Rates vs Allocated Unit Costs					
Energy Charges & Allocated Unit Costs (¢ per kWh)					
	Small	**Medium**	**Large<30**	**Large30-100**	**Large >100**
Approved Rates as of May 1, 2013	3.457	3.457	3.250	3.022	2.929
PCOSS 14 Amended Costs	4.080	3.930	3.870	3.490	3.470
Demand Charges and Allocated Unit costs ($ per kV.A)					
	Small	**Medium**	**Large<30**	**Large30-100**	**Large >100**
Approved Rates as of May 1, 2013	$8.85	$8.85	$7.51	$6.43	$5.72
PCOSS 14 Amended Costs	$6.22	$6.70	$5.98	$3.12	$2.34
Revenue Cost Coverage Ratios					
	Small	**Medium**	**Large<30**	**Large30-100**	**Large >100**
RCC%	106.2	99.4	91.3	100.0	98.6

Section:	PUB MFR 16 (PUB/MH II-182)	**Page No.:**	176 and 177 of 220
Topic:	Rate Design Principles		
Subtopic:	Basic Charges		
Issue:	Lowering of the Basic Charge		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro states that:

"While the current BMC for the SGS customer class is reasonably consistent with stated Rate Design Policy and the increase has not been met with significant customer resistance, Manitoba Hydro wishes to reduce and possibly eliminate both the electric and natural gas BMC."

QUESTION:

a) Please provide an update, if any, to the rate design principles for Manitoba Hydro and Centra as shown in the table in PUB/MH II-182 from the 2010/11 & 2011/12 GRA (pdf p.177 of 220) following the cost of service review and input from Christensen Associates.

b) As stated in PUB/MH II-182, please indicate whether it is still Manitoba Hydro's goal to reduce or possibly eliminate the Basic Charge for Manitoba Hydro and Centra, and whether this goal only applies to electric Residential or gas SGS customers.

c) Please explain whether or how MH proposes to address the rate imbalance (customer/energy) in the residential and GSS classes, where current Basic Charges cover less than the full cost of customer cost allocations.

d) Please provide MH's views on the following with respect to rate design principles:

   i. Should demand and energy rates for each class fully reflect COSS cost allocations?
   ii. Should electric heat customers be treated differently? (e.g. special class)
   iii. Should geothermal customers be subject to higher Demand charges?

RATIONALE FOR QUESTION:

To understand the interrelationship between Basic, Demand, and Energy Charges with respect to cost recovery and MH's intentions in respect of increases or decreases to each charge.

RESPONSE:

a) Rate design principles are long-lived and enduring goals used to provide broad guidance in informing rate design decisions. Rate design principles may conflict with each other and judgment must be applied in balancing the outcomes between two competing rate design principles.

   Manitoba Hydro has not found any need to change the rate design principles shown in the response to PUB/MH II-182 from the 2010/11 & 2011/12 GRA.

b) Manitoba Hydro is currently examining residential electric rate design alternatives in conjunction with two major initiatives. These initiatives are the development of a residential conservation rate design, as set out by the Province of Manitoba in Manitoba's Climate Change and Green Economy Action Plan (page 16), and the examination of Manitoba Hydro's bill affordability programs in a stakeholder engagement process currently underway. The scope of these activities is largely focused on electric residential rates at this time.

   The analysis of rate design alternatives will consider the appropriate level of the basic monthly charge, the size of the first block of energy consumed by residential customers each month, the degree of differentiation in price between the first block and the run-off rate, and the possible introduction of seasonal distinctions in rate components.

   It is premature to conclude what the outcome of these analyses will be and how the basic monthly charge would be impacted.

c) Manitoba Hydro recognizes that the level of customer-related embedded cost is one consideration in setting the level of the basic monthly charge. However, there are other factors to be taken into consideration. Other considerations such as the stability and predictability of revenue recovery, the influence of the level of energy charges on

customer usage and investment decisions, and the impact on customers in lower income segments of the population are also important considerations that need to influence the overall determination of the level of the basic charge in comparison to the level of allocated embedded cost.

In terms of General Service Small rate design, Manitoba Hydro has no immediate plans to specifically address the level of the basic charge. This matter may be examined in the future in the examination of commercial conservation rate design.

d)

i. As noted in the response to part c) above, embedded cost is only one factor to be considered in the design of rate components and that other rate design factors must be taken into consideration as well. Furthermore, Manitoba Hydro's rate design principles state that demand and energy charges should be reasonably reflective of the underlying demand and energy related costs allocated to the class. Manitoba Hydro is therefore not advocating that demand and energy charges necessarily "fully reflect" the allocated costs, but that a reasonable congruence between allocated cost and revenues exist.

ii. The impact of rate design changes on electrically heated customers is an important consideration that is being examined in the development of residential conservation rate alternatives. It is expected that the residential conservation rate design proposal that will be forthcoming will incorporate some consideration and accommodation for electrically heated customers.

iii. Residential customers who install ground source heat pump systems are subject to the residential rate which is comprised of a basic monthly charge and an energy charge but there is no demand charge. In situations where a customer's combined residential and agricultural load were to exceed 50 kW, the customer would be billed as a General Service Small (Demand) customer and would be subject to demand charges.

In the event that a residential customer installing a ground source heat pump requires a 400 amp service, their account would be subject to a basic charge of $15.14 instead of $7.57 per month, in accordance with the PUB-approved rate schedule.

Manitoba Hydro has no plans at this time to introduce demand charges for residential rates.

Section:	2015/16 GRA Revised Appendix 9.1 April 20/15; Quarterly Report Filing Attachment 3 Feb 16/16	**Page No.:**	
Topic:	Energy Purchases		
Subtopic:	MISO Imports & Wind Purchases		
Issue:	Wind Purchases Reduce Imports		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Confirm that the attached table summary of MISO energy purchases and MH's estimated wind energy purchases are reasonable (assuming no other CDN energy purchases).

b) Quantify the summer (J/J/A/S) and winter (D/J/F/M) MISO imports for 2013/14, 2014 and 2015/16.

c) Confirm or revise the estimated wind energy purchases for 2013/14, 2014/15, and 2015/16.

d) For those three years, quantify the months and GWh of wind resources that did not add to MH's opportunity sales.

MH Energy Purchases
Ref: Revised Appendix 9.1 Apr 30, 2015
Attachment 3 Feb 16, 2016

		MISO Energy Purchases			MH Wind Energy Est. Purchases ①	
		GWh	¢/kWh		GWh	¢/kWh
2013	Apr	17.10	2.90		111	
	May	2.50	3.50		105	?
	June	1.70	5.40		89	
	July	2.50	7.60		74	
	Aug	2.50	17.60		60	?
	Sept	2.70	3.90		123	
	Oct	0.70	3.30		128	
	Nov	21.70	2.50	↑	141	?
	Dec	73.10	3.70		116	
2014	Jan	176.90	4.80	560 @ 4.5	86	
	Feb	143.60	4.20	↓	25	?
	Mar	70.70	4.10		58	
	Apr	15.60	4.50		88	
	May	1.00	9.20		80	?
	June	1.70	9.10		73	
	July	2.70	3.70		71	
	Aug	5.00	5.90		37	?
	Sept	1.30	4.20		76	
	Oct	0.40	2.10		109	
	Nov	61.40	2.60	↑	99	?
	Dec	29.30	4.00		74	
2015	Jan	29.10	4.50	155 @ 4.5	97	
	Feb	27.60	5.00	↓	89	?
	Mar	9.60	1.50		99	
	Apr	2.10	3.60		88	
	May	2.30	5.00		75	?
	June	2.00	1.30		48	
	July	2.10	6.30		58	
	Aug	3.70	14.40		58	?
	Sept	4.70	5.20		78	
	Oct	15.00	2.40		99	
	Nov	3.20	2.80		77	?
	Dec	9.10	1.50		63	
2016	Jan	21.40	3.20		75	
	Feb					
	Mar					

① Assumes no Canadian purchases

RATIONALE FOR QUESTION:

Wind purchases appear to increase opportunity sales.

RESPONSE:

a) Not confirmed. The data labeled as MISO Energy Purchases provided with this question only reflects US energy imports to Canada and omits energy purchased but not delivered into Canada. The data labeled MH Wind Energy Purchases is also inaccurate as it ignores all other Canadian energy purchases. Canadian purchases can be material and ignoring them would distort any estimate of Manitoba Hydro's wind energy purchases based upon this assumption.

b)

	US Energy Imports	
	GWh	**¢/KWh**
2013/14 Summer	9	8.8
2013/14 Winter	464	4.3
2014/15 Summer	11	5.7
2014/15 Winter	96	4.2
2015/16 Summer	13	9.3
2015/16 Winter	45	2.0

c) Manitoba Hydro is unable to provide monthly wind energy data as that would be in breach of confidentiality provisions in Manitoba Hydro's wind power purchase agreements. However we are able to provide quarterly wind energy data up to 2015/16 Q3 as shown in the table below.

Manitoba Hydro is unable to provide unit cost data (c/kWh) for wind purchases as that would be in breach of the confidentiality provisions of Manitoba Hydro's wind power purchase agreements.

	Wind Energy GWh
2013/14 Q1	228
2013/14 Q2	154
2013/14 Q3	257
2013/14 Q4	294
2014/15 Q1	233
2014/15 Q2	187
2014/15 Q3	278
2014/15 Q4	277
2015/16 Q1	207
2015/16 Q2	193
2015/16 Q3	240

d) With regard to whether wind energy added to opportunity sales, all generation resources on the Manitoba Hydro system contribute to the overall supply of energy that is used to meet Manitoba and export load. As a result it is not possible to designate one supply source such as wind purchases as being the marginal resource responsible for additional opportunity sales.

Had water flows in these years not been so favourable, the same logic would lead one to conclude that all opportunity sales were the result of surplus hydraulic generation.

For the reason that any resource could be deemed to be the marginal supply source, Manitoba Hydro cannot not agree with an analysis that values a resource on a marginal basis and therefore is unable to quantify the months and GWh of wind resources that did not add to Manitoba Hydro's opportunity sales.

Section:	2015/16 GRA Revised Appendix 9.1 April 20/15; Quarterly Report filing Attachment #3 Feb 16/16;	**Page No.:**	
Topic:	Export Volumes/Prices		
Subtopic:	2013/14, 2014/15 and 2015/16 NEB Data		
Issue:	Predominance of Opportunity Sales		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Confirm or amend the attached graph.

b) Quantify MH's firm contract exports as a percentage of total sales on a monthly basis for 2013/14, 2014/15 and 2015/16.

c) Confirm that MH's average annual unit price of opportunity sales after 2008/09 has been in the range of 2-3 ¢/kWh.

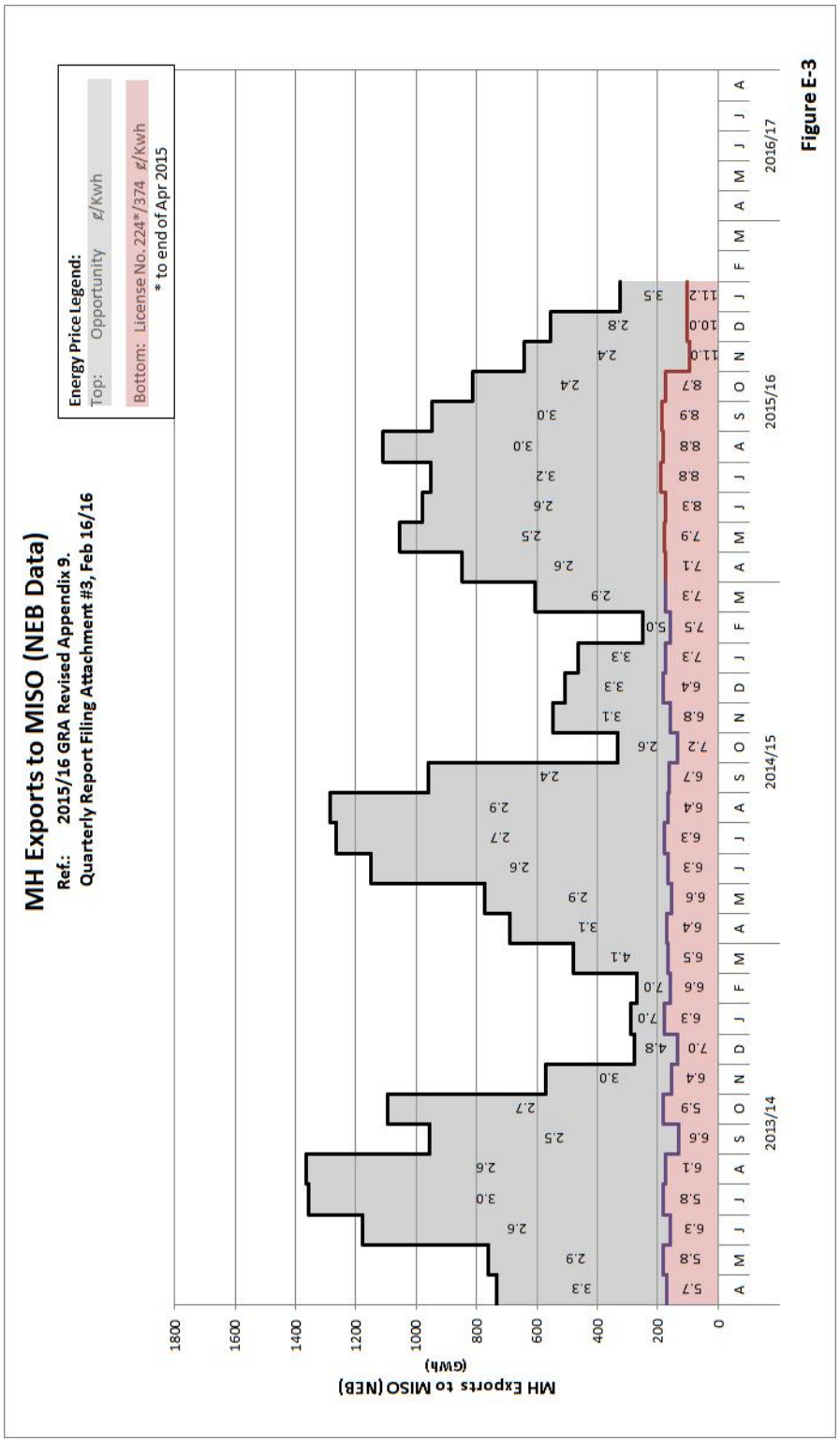

MH Exports to MISO (NEB Data)
Ref.: 2015/16 GRA Revised Appendix 9.
Quarterly Report Filing Attachment #3, Feb 16/16
Energy Price Legend:
Top: Opportunity ¢/Kwh
Bottom: License No. 224*/374 ¢/Kwh
* to end of Apr 2015
MH Exports to MISO (NEB)
(GWh)
2013/14
2014/15
2015/16
2016/17

Figure E-3

RATIONALE FOR QUESTION:

To understand the nature and value of opportunity sales.

RESPONSE:

a) Not confirmed. As this chart was not originally prepared by Manitoba Hydro, Manitoba Hydro is not in a position to amend it. This chart reflects a mixture of energy deliveries to the US as reported to the NEB and not MISO dependable and opportunity sales.

b)

	Dependable as % of Total Sales
Apr-13	49%
May-13	39%
Jun-13	41%
Jul-13	41%
Aug-13	40%
Sep-13	45%
Oct-13	38%
Nov-13	51%
Dec-13	73%
Jan-14	51%
Feb-14	47%
Mar-14	32%
Apr-14	51%
May-14	39%
Jun-14	42%
Jul-14	43%
Aug-14	41%
Sep-14	53%
Oct-14	57%
Nov-14	40%
Dec-14	64%
Jan-15	46%

Feb-15	59%
Mar-15	45%
Apr-15	44%
May-15	49%
Jun-15	49%
Jul-15	51%
Aug-15	45%
Sep-15	52%
Oct-15	55%
Nov-15	49%
Dec-15	51%
Jan-16	61%
Feb-16	55%

c) Confirmed.

Section:	2015/16 GRA MFR 9 Appendix 11.15 Appendix 11.48	**Page No.:**	4, 5, 6 4 of 5
Topic:	Future G&T Assets		
Subtopic:	Revenue Requirement Impacts		
Issue:	Incremental Costs to Firm and Opportunity		

PREAMBLE TO IR (IF ANY):

Gross revenue requirement will increase by about 50% by 2021/22 from 2015/16.

QUESTION:

a) Confirm or update the following new G&T revenue requirements:

	Bipole III & Riel	Expanded US Intertie	Keeyask	Total
Full In-service Date	2019/20	2021/22	2021/22	2021/22
Revenue Requirement (Fin/OM&A/Deprec./Tax	$330M ($323M in 2021/22)	$115M	$528M	$967M

b) Confirm that these new G&T revenue requirements will be offset in part by new revenues from Keeyask G.S. and reduced HVDC line losses.

c) Quantify the additional revenues that relate to these projects at full in-service both as dependable (firm) energy sales (Bipole III – 177 GWh/Keeyask – 3000 GWh) and as additional average year opportunity energy sales (Bipole III – 352 MW 177 GWh/Keeyask 4400 GWh).

RATIONALE FOR QUESTION:

To explore the impact of both firm and opportunity export sales on Manitoba Hydro's cost structure.

RESPONSE:

a) The following figures have been updated to reflect IFF15 based on the revised Appendix 11.15 filed in the response to PUB/MH-I-71e at the 2014/15 & 2015/16 GRA:

	Bipole III & Riel	Expanded US Intertie	Keeyask	Total
Full In-service Date	2019/20	2021/22	2021/22	2021/22
Estimated operating & carrying costs (Fin/OM&A/Deprec./Tax)	$309M (2021/22)	$113M	$493M	$915M

b) Manitoba Hydro cannot confirm the portions of export or domestic revenues which offset the estimated incremental carrying and operating costs for the major new generation and transmission projects.

Manitoba Hydro operates the integrated hydro-electric system to optimize the efficient use of water resources and maximize overall Corporate revenues for the benefit of customers. The output of one facility may not be maximized on its own but contributes to the maximization of the system as a whole. As a result, it is extremely difficult to quantify how much of the incremental export revenue offsets the estimated carrying and operating costs of major new generation and transmission projects separately from the integrated system as a whole.

The response to Financial Information MFR #9 (Appendix 11.15, p.2) indicated that MH, "…assumes that annual depreciation expense approximates revenues available to reduce debt over the life of the asset," for the purposes of understanding the estimated incremental carrying and operating costs for major new generation and transmission projects in the 2015/16 & 2016/17 GRA. MH also stated in the response, "…depreciation expense [which] approximates the revenue attributable to a project may be reasonable for understanding costs but does not reflect the [export] value of a particular asset to the integrated system," for the purposes of resource planning.

c) Manitoba Hydro can make simplifying assumptions to calculate the estimated revenue for Keeyask based on the average unit revenues for 2021/22 reflected in the response to PUB/MH-I-71a. However, as stated in the response to PUB/MH-I-38b above, it is

extremely difficult to quantify how much of the incremental export revenue offsets the estimated carrying and operating costs of major new generation and transmission projects separately from the integrated system as a whole. This Information Request discloses forecast export revenue and volume information that can be used to infer export price contract information which is commercially sensitive and confidential. Therefore, the response is being filed in confidence under Rule 13 of the Public Utilities Board's Rules of Practice and Procedure.

	Energy (GW.h)	**Average Unit Revenue ($/MW.h)**	**Estimated Revenue ($000,000)**
Keeyask Dependable (Domestic and Firm Export)	3000	[redacted]	[redacted]
Keeyask Opportunity	1400	[redacted]	[redacted]
Keeyask Total	4400		349

Section:	2015/16 GRA MFR 9 Appendix 11.15 Appendix 11.48	**Page No.:**	4, 5, 6 4 of 5
Topic:	Future G&T Assets		
Subtopic:	Revenue Requirement Impacts		
Issue:	Incremental Costs to Firm and Opportunity		

PREAMBLE TO IR (IF ANY):

Gross revenue requirement will increase by about 50% by 2021/22 from 2015/16.

QUESTION:

d) Explain why MH is proposing to assign the $973M of new revenue requirements to domestic load and dependable (firm contract) exports but not to opportunity sales.

RATIONALE FOR QUESTION:

To explore the impact of both firm and opportunity export sales on Manitoba Hydro's cost structure.

RESPONSE:

The premise of the question is not correct. Under the PCOSS14-Amended methodology Opportunity export sales will fully share in all variable costs that are part of the revenue required of Bipole III, Riel, Keeyask and the expanded US Interface. Opportunity sales are a by-product of a system built to serve Manitoba load at least cost, and are not appropriately assigned a share of embedded costs from either new or existing generation and transmission assets.

Please see Manitoba Hydro's response to PUB/MH I-2 for further discussion.

Section:	2015/16 GRA MFR 9 Appendix 11.15 Appendix 11.48	**Page No.:**	4, 5, 6 4 of 5
Topic:	Future G&T Assets		
Subtopic:	Revenue Requirement Impacts		
Issue:	Incremental Costs to Firm and Opportunity		

PREAMBLE TO IR (IF ANY):

Gross revenue requirement will increase by about 50% by 2021/22 from 2015/16.

QUESTION:

e) Confirm that the added revenue requirements of Keeyask have a unit cost of about 17 ¢/kWh if calculated with dependable energy only and about 12 ¢/kWh if calculated using average energy output.

RATIONALE FOR QUESTION:

To explore the impact of both firm and opportunity export sales on Manitoba Hydro's cost structure.

RESPONSE:

Please see Manitoba Hydro's response to PUB/MH-I-38b.

Section:	PCOSS 14	**Page No.:**	Schedules B1/B2/B3
Topic:	PCOSS14 Cost Allocation		
Subtopic:	Generation/Transmission/Distribution Costs		
Issue:	Distribution Costs Percentage of Total		

PREAMBLE TO IR (IF ANY):

PCOSS14 (Amended) would have a revised cost allocation.

QUESTION:

a) Confirm or update the attached table showing G,T&D costs by class and total class sales.

b) Confirm or update the attached table showing bulk transmission/ distribution plant/ distribution services unit costs and the percentage that these contribute to class costs.

c) Expand the table in (b) to show the total of sub-transmission, distribution, and distribution services costs ($M) and percentage of total cost by class for PCOSS08 to PCOSS14 (Amended).

d) Confirm whether the percentage of total distribution costs for each class has remained essentially unchanged over the past 10 years.

PCOS 14 Cost Allocations

Ref: PCOSS14 Schedules B1/B2/B3

	Generation ($M)	**Transmission** ($M)	**Distribution** ($M)	**Energy Sales** (GWh)
Residential	264.4 (3.5 ¢/kWh)	67.9 (0.9 ¢/kWh)	264.8 (3.5 ¢/kWh)	7404
GSS-ND	60.5 (3.7 ¢/kWh)	14.5 (0.9 ¢/kWh)	50.1 (3.1 ¢/kWh)	1606
GSS-D	75.0 (3.7 ¢/kWh)	17.1 (0.8 ¢/kWh)	37.3 (1.8 ¢/kWh)	2048
GSM	113.2 (3.5 ¢/kWh)	26.3 (0.8 ¢/kWh)	47.3 (1.5 ¢/kWh)	3175
GSL <30	59.6 (3.5 ¢/kWh)	13.6 (0.8 ¢/kWh)	19.4 (1.1 ¢/kWh)	1702
GSL 30-100	42.3 (3.3 ¢/kwh)	8.4 (0.7 ¢/kwh)	6.1 (0.5 ¢/kWh)	1327
GSL >100	155.4 (3.2 ¢/kWh)	29.5 (0.6 ¢/kWh)	2.4 (0.05 ¢/kWh)	4904
ARL	2.8 (2.8 ¢/kWh)	0.4 (0.4 ¢/kWh)	18.5 (18.5 ¢/kWh)	100
Subtotal	**773.8**	**177.9**	**446.3**	
Exports	279.8 (3.1 ¢/kWh)	31.1 (0.3 ¢/kWh)	0 0	9013
Total	**1053.6**	**209**	**446.3**	**$1708.9 + $34.4 Net Export Allocation**
Exports	27%	15%	0	

Distribution System Cost Allocations – PCOSS14

Ref: PCOSS14 Schedule B3

(Subtransmission/ Distribution Plant/ Distribution Services)

MH's distribution system incurs annual costs of about $450M which for various customer classes amount to:

Class	Average Cost	Percentage of Class Cost
• Residential	3.5 ¢/kwh	44% of total cost
• GSS-ND	3.1 ¢/kWh	40% of total cost
• GSS-D	1.8 ¢kWh	29% of total cost
• GSM	1.5 ¢/kWh	25% of total cost
• GSL < 30	1.1 ¢/kWh	21% of total cost
• GSL 30-100	0.5 ¢/kWh	11% of total cost
• GSL < 100	0.05 ¢/kWh	1% of total cost
• ARL	18.5 ¢/kWh	85% of total cost
• Exports	0	N/A

RATIONALE FOR QUESTION:

To understand the relative importance of G&T&D costs.

RESPONSE:

Response to parts a) and b)

PCOSS14-Amended

Class	Metered Energy mWh	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtrans, Dist Cust Serv Dist Plant Cost ($000)	%
Residential	7,404,453	590,034	289,091	49.0%	46,667	7.9%	254,276	43.1%
unit Cost			0.039		0.006		0.034	
General Service - Small Non Demand	1,605,511	124,448	66,330	53.3%	9,967	8.0%	48,151	38.7%
unit Cost			0.041		0.006		0.030	
General Service - Small Demand	2,047,715	129,853	82,121	63.2%	11,798	9.1%	35,933	27.7%
unit Cost			0.040		0.006		0.018	
General Service - Medium	3,174,662	187,952	124,313	66.1%	18,110	9.6%	45,528	24.2%
unit Cost			0.039		0.006		0.014	
General Service - Large <30kV	1,702,481	93,649	65,595	70.0%	9,361	10.0%	18,692	20.0%
unit Cost			0.039		0.005		0.011	
General Service - Large 30-100kV	1,327,210	57,805	46,085	79.7%	5,831	10.1%	5,889	10.2%
unit Cost			0.035		0.004		0.004	
General Service - Large >100kV	4,903,742	192,023	169,280	88.2%	20,447	10.6%	2,296	1.2%
unit Cost			0.035		0.004		0.000	
Area & Roadway Lighting	100,487	21,577	3,014	14.0%	322	1.5%	18,241	84.5%
unit Cost			0.030		0.003		0.182	
Total General Consumers		1,398,309	846,340	60.5%	122,637	8.8%	429,332	30.7%
Export	9,013,000	254,070	232,148	91.4%	21,922	8.6%	-	
unit Cost			0.026		0.002		-	
Total System		1,661,701	1,087,260	65.4%	144,559	8.7%	429,882	25.9%

c) PCOSS08

Class	Metered Energy mWh	Subtrans, Dist Cust Serv Dist Plant Cost	
Residential	6,577,526	232,225	51.4%
unit Cost		$ 0.035	
General Service - Small Non Demand	1,328,832	42,257	47.7%
unit Cost		$ 0.032	
General Service - Small Demand	2,038,415	35,624	34.4%
unit Cost		$ 0.017	
General Service - Medium	2,948,717	44,532	31.3%
unit Cost		$ 0.015	
General Service - Large <30kV	1,611,803	21,532	29.0%
unit Cost		$ 0.013	
General Service - Large 30-100kV	987,630	4,636	13.7%
unit Cost		$ 0.005	
General Service - Large >100kV	5,202,246	1,707	1.1%
unit Cost		$ 0.000	
Area & Roadway Lighting	95,997	15,444	85.1%
unit Cost		$ 0.161	
Total General Consumers		398,313	37.5%
Export	7,707,000	0	0.0%
unit Cost		$ -	
Total System		398,313	27.5%

d) Not confirmed. The relative shares of ‘distribution’ costs to total costs have not remained unchanged since PCOSS08, dropping from 37.5% of costs in PCOSS08 to 30.7% in PCOSS14-Amended. The change is consistent with investment in new major generation and transmission projects since 2008 that has increased G&T costs to greater extent than other functions.

Section:	PCOSS14; PRP 14	**Page No.:**	
Topic:	Power Resources Utilization		
Subtopic:	Non-hydraulic Resources		
Issue:	Cost effective Use of Resources		

PREAMBLE TO IR (IF ANY):

MH's use of non-hydraulic resources has been relatively low in recent years.

QUESTION:

a) Provide a graphical illustration of MH's power resources for each of the years 2013/14 and 2014/15, and forecasted for 2018/19 and 2021/22, showing how MH's domestic load, firm exports and opportunity exports would be served by:

- HVAC hydraulic generation (dependable/average/maximum)
- HVDC hydraulic generation (dependable/average/maximum)
- wind purchases (must use)
- thermal generation (if market competitive)
- imports

b) Quantify MH's annual thermal generation utilization from 2001/02 to date.

RATIONALE FOR QUESTION:

To understand how MH plans and actually uses its hydraulic and non-hydraulic resources.

RESPONSE:

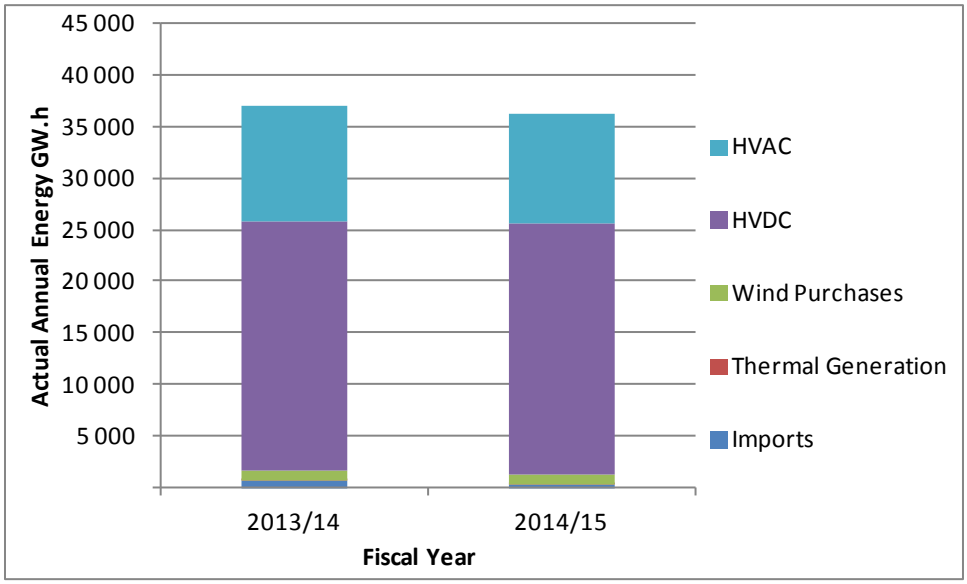
The Preamble to this question states "MH's use of non-hydraulic resources has been relatively low in recent years". This statement is correct, however, Manitoba Hydro notes that hydraulic generation in recent years, including 2013/14 and 2014/15, has been above average. The Manitoba Hydro system is operated to reduce system costs such that under favourable flow conditions, generation available from hydroelectric resources is used to offset thermal generation and imports.

The requested information is presented in the following charts. It should be noted that:

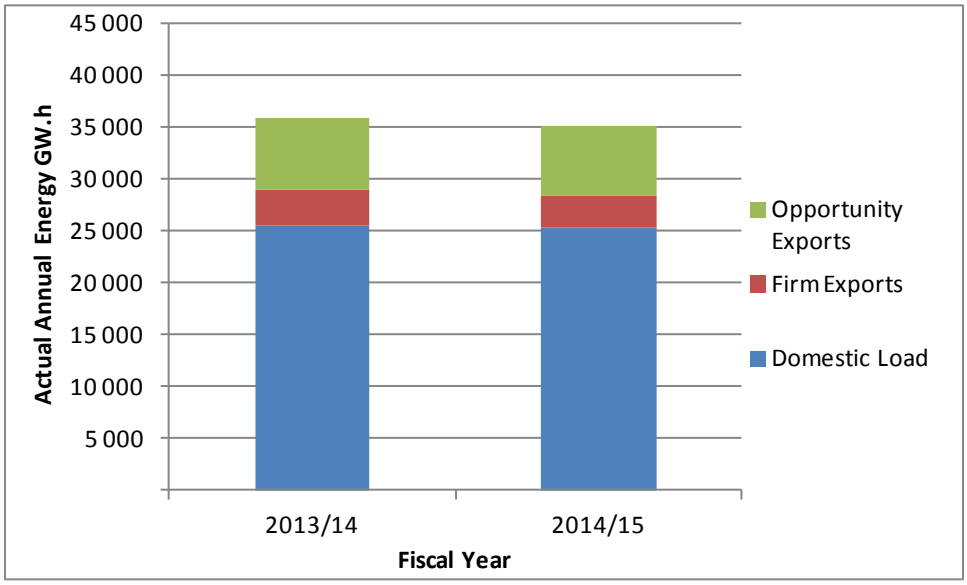
- HVDC values include generation from Long Spruce, Kettle, Limestone Generating Stations and generation from the Keeyask Generating Station for the years it is in service.
- HVAC values include generation from the Winnipeg River plants (Pointe du Bois, Slave Falls, Seven Sisters, McArthur, Great Falls and Pine Falls), as well as Grand Rapids, Jenpeg, Kelsey, and the two Laurie River stations. Wind purchase, thermal generation and imports are also part of the HVAC system, but are listed separately.
- Forecasted generation for 2018/19 and 2021/22 is calculated at generation.
- Tables contain energy values.
- Domestic Load is Net of DSM, Bipole III reduced losses and Construction Power.
- Actual firm exports were as sold under contract, whereas forecasted firm exports represent all committed and uncommitted firm export energy.
- Actual demand is less than actual supply due to system losses.

a)

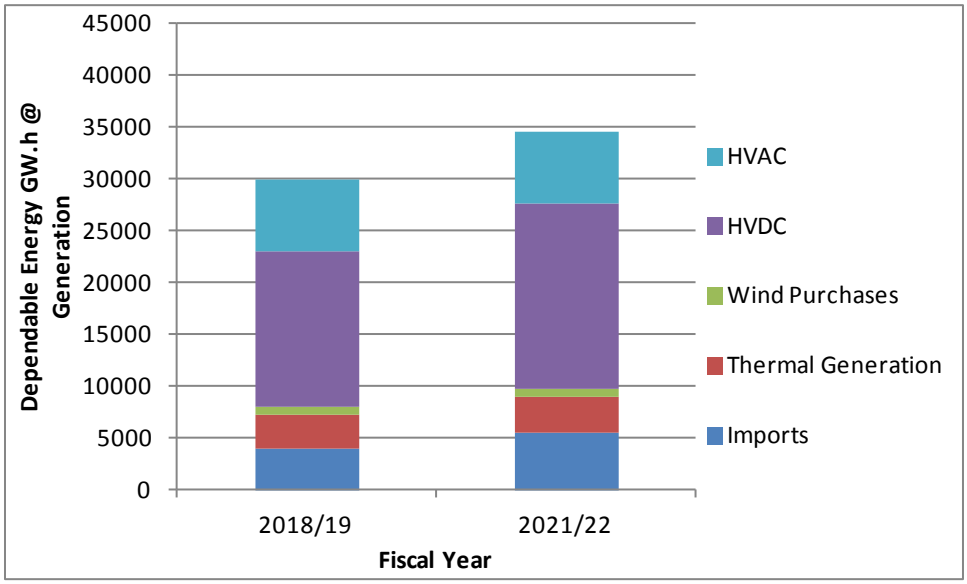
Supply Resources, Actual data 2013/14, 2014/15, GW.h



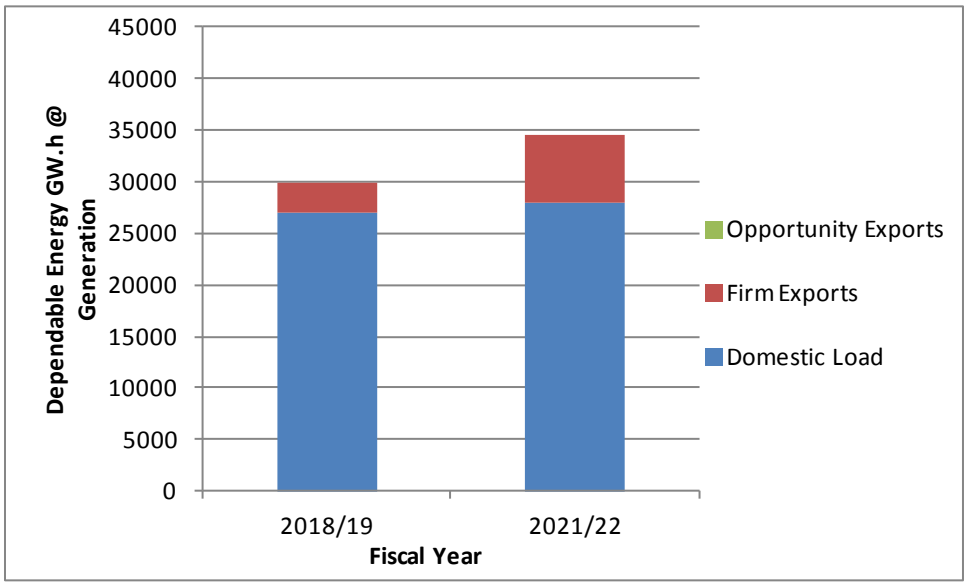
Demand, Actual data, 2013/14, 2014/15, GW.h



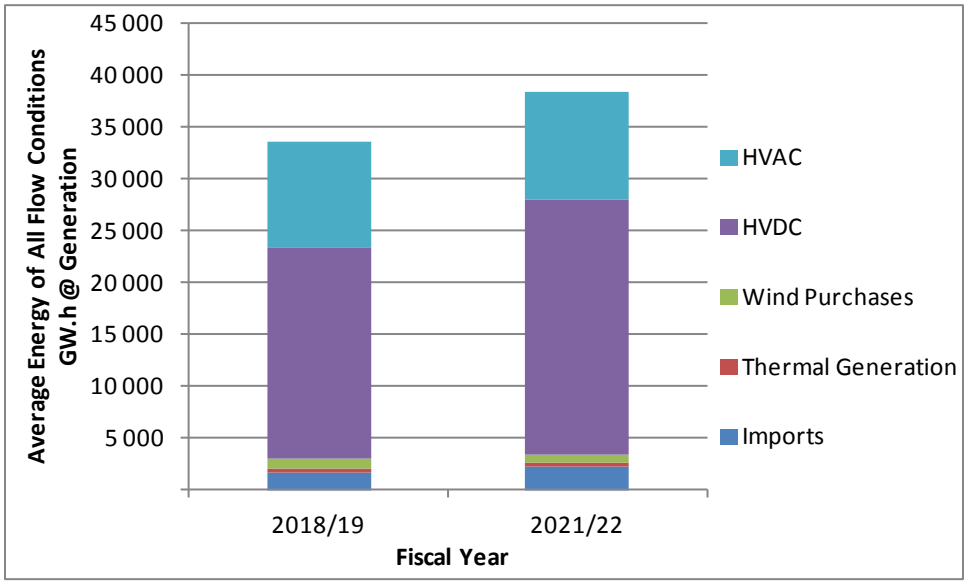
Forecasted Supply, Dependable @ Generation, GW.h



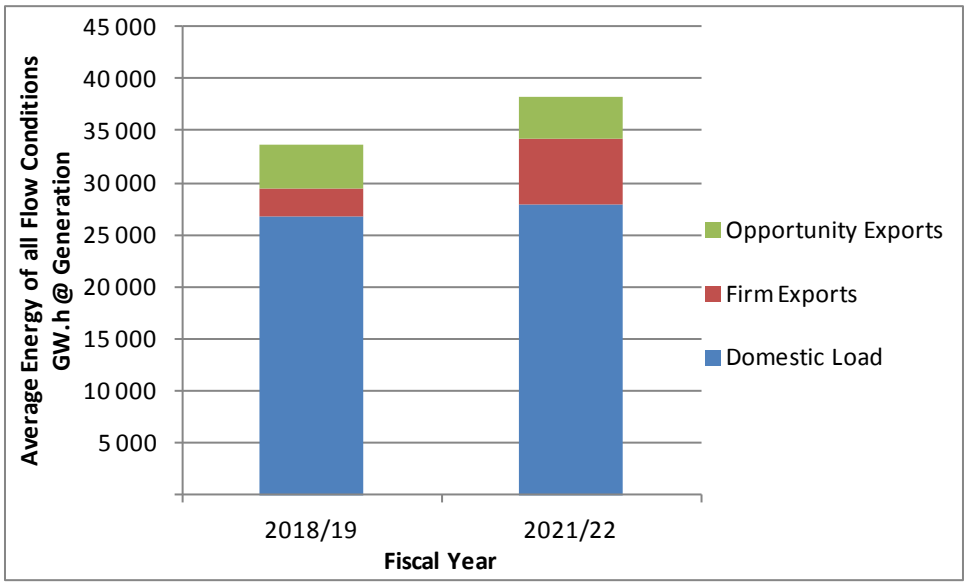
Forecasted Demand, Dependable @ Generation, GW.h



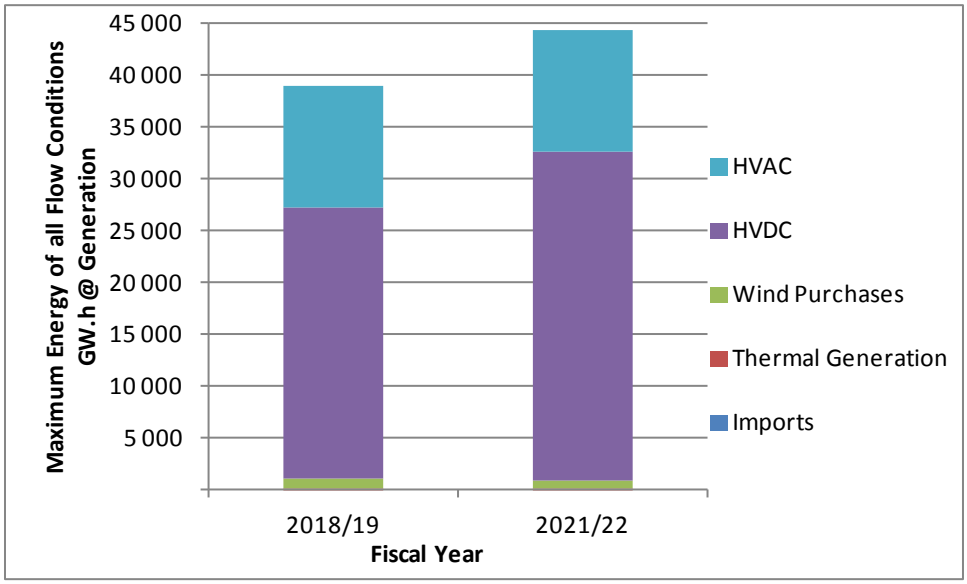
Forecasted Supply, Average @ Generation, GW.h



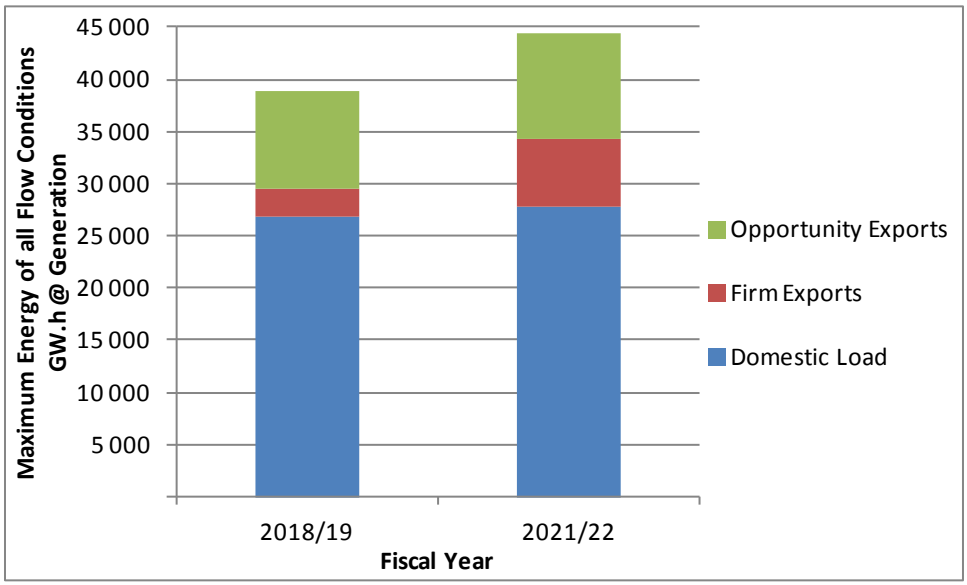
Forecasted Demand, Average @ Generation, GW.h



Forecasted Supply, Maximum @ Generation, GW.h



Forecasted Demand, Maximum @ Generation, GW.h



b) Below is a table with Manitoba Hydro's annual thermal generation from 2001/02 to date.

Fiscal Yr	Total Thermal (Mwh)
2001-02	481
2002-03	601
2003-04	853
2004-05	414
2005-06	401
2006-07	522
2007-08	457
2008-09	335
2009-10	143
2010-11	66
2011-12	77
2012-13	83
2013-14	131
2014-15	69

Section:	PCOSS14	**Page No.:**	Schedules D1 and D2
Topic:	Export Cost Allocation		
Subtopic:	Generation and Transmission in Cost Sharing		
Issue:	7x16 Opportunity Sales		

PREAMBLE TO IR (IF ANY):

MH's SEP and 2CP approach to weighting G&T cost drivers appears to exclude certain export sales.

QUESTION:

a) Confirm and explain why, in the attached table from Schedule D-2, MH's use of 5010 GWh in the generation and transmission fixed cost sharing includes approximately 3600 GWh of firm contract (5 x 16) or potential firm contracts (5 x 16) sales from dependable energy resources and approximately 1400 GWh of 7 x 8 night-time opportunity sales.

b) Confirm that 3800 GWh of MH's 7 x 16 opportunity energy sales attract no allocations of fixed costs for G&T.

c) Explain why 1400 GWh of 7 x 8 would be allocated fixed costs but 3800 GWh of 7 x 16 (peak and shoulder) would not be allocated fixed costs.

d) Confirm that, in schedule D-1, MH excludes the same 3800 GWh of 7 x 16 energy from the calculation of the Winter/Summer/2CP peak demand that is used for transmission costs allocation.

PCOSS14 Schedule D2 with Average Demand

(kWh)	Spring (Apr-May)						Summer (Jun-Sep)					
	Peak Energy	Avg Dmd	Shoulder Energy	Avg Dmd	Off-Peak Energy	Avg Dmd	Peak Energy	Avg Dmd	Shoulder Energy	Avg Dmd	Off-Peak Energy	Avg Dmd
# of hours	352	MW	624	MW	488	MW	672	MW	1280	MW	976	MW
Exports	214,892,366	610	394,273,751	632	214,162,497	439	533,651,385	794	1,000,120,297	781	634,300,041	650
Weighting Factor	3.657		3.043		1.739		4.556		3.011		1.000	

	Fall (Oct-Nov)						Winter (Dec-Mar)								
	Peak Energy	Avg Dmd	Shoulder Energy	Avg Dmd	Off-Peak Energy	Avg Dmd	Peak Energy	Avg Dmd	Shoulder Energy	Avg Dmd	Off-Peak Energy	Avg Dmd	Total Energy	Avg Dmd	Weighted Energy/1000
# of hours	328	MW	648	MW	488	MW	656	MW	1280	MW	968	MW	8760	MW	
Exports	209,648,525	639	399,109,735	616	254,530,786	522	313,318,899	478	570,134,666	445	272,145,303	281	5,010,288,250	572	15,381,070
Weighting Factor	4.063		3.189		1.813		5.049		3.588		2.691				

March 7, 2016 PUB Advisor Document

RATIONALE FOR QUESTION:

To clarify which exports drive allocations of fixed costs.

RESPONSE:

a) Not confirmed. The relative volumes of dependable and opportunity sales in the COSS are based on the ratio of energy surplus to domestic needs under dependable flows compared to under average flows. The total export energy in Schedule D-2 represents the portion of forecast export sales assumed Dependable for COSS purposes, which is then divided into the twelve time periods based on the proportion of actual export sales in each period from Load Research studies. The Load Research studies provide load information for exports as a whole and do not distinguish between firm or opportunity sales.

Response to parts b) to d):

Manitoba Hydro cannot confirm the calculations and conclusions provided.

Manitoba Hydro can confirm that in PCOSS14 and PCOSS14-Amended, Opportunity exports are not allocated any embedded G&T costs, and Schedules D-1 and D-2 in those studies allocate embedded G&T costs to Dependable exports (and domestic customers) only. The determination of dependable and opportunity sales is based on forecasted energy averaged based on years 3-8 of the IFF as discussed in Manitoba Hydro's Submission (page 16) and responses to PUB/MH I-67c and COALITION/MH I-21d-e.

Section:	PCOSS14	**Page No.:**	Schedules D1 and D2
Topic:	Export Cost Allocation		
Subtopic:	Generation and Transmission Cost Sharing		
Issue:	7x16 Opportunity Sales		

PREAMBLE TO IR (IF ANY):

Generation cost allocation on an energy basis may not recognize the demand component of the HVDC system.

QUESTION:

a) Confirm that 7 x 8 domestic and opportunity sales do not drive the system capacity-related fixed costs of hydraulic generation or transmission.

b) Confirm that fixed costs of hydraulic generation or transmission related to system capacity are driven by domestic demand and firm contract exports in the 7 x 16 timeframe.

RATIONALE FOR QUESTION:

To understand drivers for allocation of generation and transmission fixed costs.

RESPONSE:

a) Confirmed. To the extent that there are any capacity related fixed costs associated with hydraulic, thermal or transmission facilities these would not be attributable to electricity sales in the 7 x 8 hours.

b) Not confirmed. Manitoba Hydro build facilities as required to serve Manitoba load at overall least cost, which means planning for capacity to serve peak domestic demand and capacity planning reserve margins. Manitoba Hydro's transmission planning criteria and NERC standards, which require meeting peak domestic demand (usually in the 5x16 weekday hours), drive the need for transmission assets.

Firm export contract obligations that coincide with peak domestic demand may advance the need for capacity resources compared to domestic demand alone.

Section:	PCOSS14	**Page No.:**	Schedules D1 and D2
Topic:	Export Cost Allocation		
Subtopic:	Generation and Transmission Cost Sharing		
Issue:	7x16 Opportunity Sales		

PREAMBLE TO IR (IF ANY):

Generation cost allocation on an energy basis may not recognize the demand component of the HVDC system.

QUESTION:

c) Confirm that the system capacity G&T fixed costs are largely included in generation on an energy share basis, but could reasonably have a demand component.

RATIONALE FOR QUESTION:

To understand drivers for allocation of generation and transmission fixed costs.

RESPONSE:

To clarify, Manitoba Hydro classifies generation costs on an energy basis, but utilizes an allocation methodology that implicitly considers a demand component as well as an energy component to these costs.

In effect, Manitoba Hydro's weighted energy allocation of generation costs classifies and allocates these costs in one step. Generation-related costs including Northern A/C collector lines and HVDC facilities are classified into 12 different cost drivers reflecting the varying seasonal and hourly costs associated with domestic energy sales. The weightings are applied to energy use in each of the 12 periods based on the effective cost differences in these periods that implicitly recognizes the value of capacity.

All methods for classifying and allocating generation-related costs are complicated by the fact that generation facilities produce two products jointly, those being energy and demand,

instantaneously. These products are inseparable and are used differently by different customer classes. A classification and allocation methodology attempts to estimate a demarcation point between the generation-related costs incurred to provide energy and the costs incurred to provide demand, either implicitly or explicitly.

Manitoba Hydro moved a weighted energy allocation in 2006 at the advice of its consultant at that time, NERA. Prior to this time, Manitoba Hydro used a System Load Factor ("SLF") approach for generation and transmission costs. The SLF approach classified generation and transmission capacity costs based on the overall load factor of the system. The remaining costs were deemed energy-related. While fairly straightforward in terms of application, it is not Manitoba Hydro's preferred approach to classifying fixed costs for a predominantly hydraulic system. Hydraulic facilities, by their nature, have a high fixed cost and very low variable cost. And once in place it makes most sense, economically, to run these facilities as much as possible, and may be arguably viewed as fixed costs having been incurred to meet much of the energy needs of customers. In a predominantly hydraulic generating system, the use of the SLF approach would tend to overclassify these fixed costs as capacity related.

Manitoba Hydro adopted the use of marginal costs to classify and allocate generation costs to better reflect cost causation. It better reflects how Manitoba Hydro plans and operates its largely hydraulic system, facilities that are designed to operate all the time to take advantage of their relatively low variable costs. The incorporation of a proxy for the current market price represents Manitoba Hydro's opportunity cost associated with the revenue given up or the cost incurred to import. It also allocates proportionately more generation-related costs to those customer classes who use more of the higher value energy, and thus also reflects equity and efficiency goals within the context of embedded cost of service. The methodology is relatively simple, straightforward, and lends itself to greater refinement than a capacity/energy split.

Section:	Appendix 3.1	**Page No.:**	9
Topic:	Exports		
Subtopic:	Allocation of Net Export Revenue		
Issue:	Basis of Allocation		

PREAMBLE TO IR (IF ANY):

Net export revenues are allocated to customer classes on the basis of total allocated cost not total cost, which also includes direct cost assignments.

QUESTION:

a) What is the justification for using total allocated costs instead of total costs to allocate net export revenues?

b) Please list, describe and discuss Manitoba Hydro's reasons for not selecting other options being considered by Manitoba Hydro, by Christensen Associates in its reports prepared for Manitoba Hydro, and by NERA in reports delivered in work associated with Manitoba since 2004 for the allocation of net export revenue.

RATIONALE FOR QUESTION:

The use of total cost or total allocated costs has a significant impact the RCC for the streetlight class. This review needs to give renewed consideration to other methodologies.

RESPONSE:

a) The allocator used for Net Export Revenue excludes the costs of dedicated or end-use facilities that are directly assigned to customer classes, namely the costs related to DSM and Area and Roadway Lighting. DSM is generally related to facilities located on customer premise and beyond the point of delivery, while ARL costs are related to dedicated end-use facilities that would be considered beyond the point of delivery for most customer classes. The decision not to provide these costs with a NER offset ensures these facilities are not provided a benefit that is not reasonably attributable to other end

use portion of load, such as refrigerators or stoves used by Residential or General Service classes.

b) Please see Manitoba Hydro's response to PUB/MH I-18a-h.

Section:	Appendix 3, Schedule E1	**Page No.:**	2
Topic:	Cost Classification		
Subtopic:	Classification of Generation Costs		
Issue:	Basis of Allocation		

PREAMBLE TO IR (IF ANY):

In schedule E1, over $9 million in direct expenses to the diesel class are functionalized as generation and classified as customer related. However, the model of PCOSS14 (Amended) provided on March 11 shows these costs as classified as energy in the detailed allocation tables. Similarly, the $587,000 of diesel direct allocations that are functionalized as distribution are classified as customer-related in schedule E1. But in the detailed allocation tables, only 40% of the cost is classified as customer related and 60% is classified as demand related.

QUESTION:

a) What are these costs?

b) In MH's view, what is the proper classification of these costs?

RATIONALE FOR QUESTION:

Want clarification on the inconsistency in the model.

RESPONSE:

a) The $587,000 directly assigned to Diesel in Schedule E1 includes the cost of Distribution Plant and Customer Service, which are tracked at the cost center level in SAP to allow direct assignment to the Diesel class. The schedule also includes Diesel Generation costs of $9.361 million.

b) Manitoba Hydro considers the costs as shown in Schedule B2 to be the appropriate Classification of Diesel costs; $587,000 classified 60/40 to Demand/Customer and $9.361 million as Energy. Please note that costs shown on Schedule B2 are net of allocated Net Export Revenue.

Section:	Appendix 3.1	**Page No.:**	26
Topic:	Cost Functionalization		
Subtopic:	Functionalization of Communications Equipment		
Issue:	Basis of Functionalization		

PREAMBLE TO IR (IF ANY):

A portion of interest and capital tax for communications and control facilities is functionalized 36%/28%/36% to Generation, Transmission, and Sub-Transmission respectively.

QUESTION:

a) What costs are functionalized on this basis?

b) How were these functional allocators derived?

c) How long has MH been using this allocation in its cost of service studies?

d) Is any portion of communication system O&M cost and depreciation expense functionalized on this basis? If so, what O&M and depreciation expense was allocated on this basis in the PCOSS14 (Amended)?

RATIONALE FOR QUESTION:

To understand any differences in allocation of communications costs across categories of cost.

RESPONSE:

The costs of communication provided for system control purposes including communications, instrumentation monitoring and SCADA is functionalized 36/28/36% to Generation, Transmission, and Sub-Transmission in the COS. These ratios are used to functionalize the Operating and Depreciation costs of these facilities, as well as rate base and associated Interest costs. These ratios have been in use since 1997. Any updates would be expected to have a negligible impact to RCC given the dollars involved.

Section:	Appendix 3.1	**Page No.:**	26
Topic:	Cost Functionalization		
Subtopic:	Functionalization of Buildings & Equipment		
Issue:	Basis of Functionalization		

PREAMBLE TO IR (IF ANY):

The PCOSS14 states that "Depreciation costs for these non-facility cost centres, as they are called in SAP, are allocated back to facility cost centres based on specific assessment cycles within the system. These assessments bring facility cost centres to full cost which can then be appropriately functionalized."

QUESTION:

a) What is a facility cost centre and a non-facility cost centre?

b) What does "full cost" mean in this context?

RATIONALE FOR QUESTION:

To understand the accounting of these costs.

RESPONSE:

a) Facility cost centres are used to capture the investment in, and costs associated with maintaining or operating, facilities used to produce, transmit or distribute electrical energy or involved in providing customer service.

   Non-facility cost centres capture the investment and costs associated with various administrative services/functions or facilities which support administrative functions. These administrative costs include activities such as human resources, payroll, building costs and other such costs incurred to support the line activities that provide the delivery of power to our customers. These costs are allocated to facility cost centres on the basis of labour costs in Manitoba Hydro's financial reporting system, SAP.

b) "Full cost" in the above discussion refers to a facility cost centre that has been allocated a share of the depreciation related to these administrative functions. The process is used for both operating and depreciation costs. Allocating administrative costs to a facility cost centre, which is in turn functionalized, allows Manitoba Hydro to functionalize these costs without the need for explicit functionalization of administrative costs in the COSS.

Rate base for the non-facility costs centres, and the associated Interest costs, still require explicit functionalization in the COSS.

Section:	Appendix 3.1	**Page No.:**	27
Topic:	Cost Functionalization		
Subtopic:	Functionalization of Communications Equipment		
Issue:	Basis of Functionalization		

PREAMBLE TO IR (IF ANY):

Functionalization of communications system O&M is done "off-line," as in outside the SAP.

QUESTION:

How, if at all, does this differ from the functionalization of communications system interest and capital tax?

RATIONALE FOR QUESTION:

To understand any differences in allocation of communications costs across categories of cost.

RESPONSE:

Communications, excluding costs discussed in PUB/MH I-45, are functionalized in the COS between Generation, Transmission, Subtransmission and Distribution Plant. The allocation basis used to functionalize communications is specific to the costs being allocated:

Operating - in proportion to functionalized operating costs, excluding Distribution Services, ARL and Diesel

Depreciation – in proportion to functionalized depreciation costs, excluding Distribution Services, ARL and Diesel

Interest (rate base) – in proportion to functionalized operating costs, excluding Water Rentals, Fuel, Power Purchases, Distribution Services, ARL and Diesel. The

approach to functionalizing rate base is consistent with treatment of Building and General Equipment rate base.

Section:	Appendix 3.1	**Page No.:**	30
Topic:	Cost Classification		
Subtopic:	Classification of Distribution Costs		
Issue:	Basis of Allocation		

PREAMBLE TO IR (IF ANY):

Poles and wires are classified 60% to demand and 40% to customers, whereas transformers are classified 100% to demand.

QUESTION:

What is the justification for using different classifications of poles and wires and transformers?

RATIONALE FOR QUESTION:

Other utilities classify transformer costs on a customer basis, but not poles and wires.

RESPONSE:

The 60/40 demand and customer split recognizes that the design for poles and wires consider line length and customer density, which are in turn driven by where customers choose to locate, in addition to the load requirements of the customers. Growth in demand can require upgrades however; it is just as likely that such upgrades would be triggered by an increasing number of customers. This treatment recognizes that customer count is a valid cost driver of poles and wires.

Transformers are more likely to relate to the load being served (electric heat load vs. non-electric heat load) and Manitoba Hydro therefore treats them as 100% demand. Manitoba Hydro notes that in the CA Report (page 18) dated 2012, CA advises that this is consistent with industry practice.

Section:	Appendix 4	**Page No.:**	30
Topic:	Cost Allocation		
Subtopic:	Primary/Secondary Split of Distribution Costs		
Issue:	Basis of Allocation		

PREAMBLE TO IR (IF ANY):

MH states that "Customers in the General Service Large 0-30kV class are responsible for providing their own transformers, and therefore do not use MH's secondary distribution facilities. Accounting records do not fully segregate these costs and to accommodate this change, MH will rely upon a 70/30 split of primary and secondary voltage. This ratio the best available estimate of the relative cost portions…"

QUESTION:

a) What makes this ratio the best available estimate of relative costs?

b) Did MH investigate similar cost ratios used by other utilities? If so, please provide the results of its investigation.

RATIONALE FOR QUESTION:

Would like more information on the basis for the 70/30 split.

RESPONSE:

Manitoba Hydro's accounting records do not segregate the costs of primary and secondary distribution, other than for underground distribution. The 70/30 primary to secondary cost split is based on the professional judgment and experience of the treatment of distribution investment of other utilities by its external expert consultant in 1991. No other more current estimates are available and any updates are expected to provide minimal improvements which make this the best available estimate of the relative costs.

Section:	Section 7.1.2	**Page No.:**	15
Topic:	Exports		
Subtopic:	Assignment to Dependable & Opportunity Sales		
Issue:	Hybrid Sales		

PREAMBLE TO IR (IF ANY):

MH refers to "hybrid" sales as those that are long-term firm sales backed by external resources.

QUESTION:

a) Please provide a list of all such sales included in the PCOSS14 (Amended).

b) After Keeyask is in service, please describe any anticipated reduction or expansion of such sales.

c) What total kWh of hybrid sales were included in the PCOSS14 (Amended) and are projected for the first full year Keeyask is in service assuming a median water year?

RATIONALE FOR QUESTION:

Would like more information to assess significance and reasonableness of MH approach.

RESPONSE:

a) There are no hybrid sales in the PCOSS14-Amended. The only hybrid sale in MH's export portfolio is the NSP 375/325 System Power Sale and supporting NSP 350 MW Diversity Sale agreements. These agreements commenced May 1, 2015 which is beyond fiscal 2013/14 and the scope of PCOSS14 (Amended).

b) After Keeyask is in service, the NSP 375/325 MW System Power Sale and the NSP 350 MW Diversity Sale remain in place until June 2025.

c) As indicated in part a) there are no hybrid sales within the scope of PCOSS14-Amended. In the first full year of Keeyask the energy associated with the NSP hybrid sale is 1,698 GWh under all flow conditions including median, unless Manitoba Hydro declares Adverse Water Conditions.

Section:	Section 7.2	**Page No.:**	20
Topic:	Generation Allocation		
Subtopic:	Capacity Value		
Issue:	Demand-based Allocation of Generation		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro uses the Reference Discount for its curtailable rate program as the value of capacity included in the weighted energy allocator.

QUESTION:

Please define the Reference Discount and explain how it is calculated.

RATIONALE FOR QUESTION:

Would like more information to assess the reasonableness of MH approach compared to alternative capacity values or demand weighting.

RESPONSE:

The Reference Discount represents the value of Curtailable load to Manitoba Hydro and is an amount credited each month to customers participating in the Curtailable Rate Program (CRP) in exchange for having Planning and/or Contingency Reserve load available. The amount of the Reference Discount is related to the marginal value of capacity, expressed in Canadian dollars and adjusted each year by the rate of inflation.

Each year the Reference Discount increases by the rate of inflation, with the last approved value being $3.40 per kW per month effective April 1, 2015 as per Board Order 44/15 dated April 23, 2015. PCOSS14 incorporated the annual Reference Discounts from 2004/05 to 2011/12, which were $2.76 in 2004/05, increasing to $3.17 per kW per month by 2011/12.

An explanation of the value of Curtailable load to Manitoba Hydro is provided each year as Attachment 1 of the annual CRP Report filed with the Public Utilities Board. Attachment 1 of the 2014/15 CRP (the most recent filed) is replicated below for reference:

ESTIMATE OF THE VALUE OF CURTAILABLE LOAD TO MANITOBA HYDRO

The value of curtailable load to Manitoba Hydro is related to an estimate of the marginal cost of firm, long-term capacity. Over the long term, a representative value for capacity can be developed by estimating the annual carrying cost (includes finance and depreciation costs but not operating/fuel costs) of the lowest cost resource required to provide capacity to Manitoba Hydro, which is a simple cycle combustion turbine (SCCT). In 2005 the annual carrying cost of a SCCT was estimated to be $78 per kW per year, or $6.50 per kW per month, evaluated at load. It was proposed that this cost would escalate at the rate of inflation. This cost was subsequently reviewed in 2012 and was found to be appropriate going forward. This approach has the advantage of providing a clear transparent value, which is also stable over time and is consistent with the approach that is utilized to evaluate the benefits of other resource options, such as DSM, that may have a capacity component.

Curtailable load is less valuable than a generation resource such as a SCCT. The SCCT can provide more flexibility in dispatch and also has the capability to deliver for longer time periods during extended emergency situations. Once in place, a SCCT can be relied upon as a permanent, long-term resource, unlike curtailable load which can be terminated with a notice period of one year. Curtailable load normally has more value in the summer months, when it can assist in supporting seasonal capacity exports, and in the peak winter months, when it may add reliability to the Manitoba Hydro system. Curtailable load will provide more winter reliability benefits in years in which there is little capacity surplus on the system. When there is a significant capacity surplus on the Manitoba Hydro system, curtailable load provides less winter value than it would, for example, in the period around the 2023/24 time period, when the requirement to add generation to serve domestic customers may be expected to occur with 2013 planning assumptions and base demand side management program assumptions. The value of reliability benefits in a single year is not easily determined, which is why longer-term levelized values are used to infer the benefits of curtailable load.

The economic benefits of curtailable load can vary considerably year to year for a number of reasons. In the case of Option R CRP, the economic benefits derived from this option will vary depending on water conditions. Export market conditions can also impact the value of

curtailable load to Manitoba Hydro. In the MISO market, current supply and demand conditions for capacity resources can cause variability in the near term value of capacity resources. Use of a longer-term levelized value maintains stability in CRP pricing, therefore sheltering the CRP customer from these sources of variability.

As described above curtailable load is less valuable than a SCCT because it has limited dispatchability, is not sustainable in reducing load over longer periods, and is not guaranteed to exist in the long term. Therefore in order to reflect these factors, curtailable load is assigned a long-term levelized value that is 42% of the annual carrying cost of a SCCT. After consideration of inflation subsequent to the 2011 base year, this yields an estimate of benefits for the year beginning April 1, 2014 of $3.36 per kW/month, which is referred to as the "Reference Discount". This value would apply to the curtailable rate option that provides the most value to Manitoba Hydro, that being Options AE and RE, for which the discount is set to return 100% of the estimated value of curtailable load to the customer. Other options provide less flexibility and are accordingly worth less to Manitoba Hydro. These have been priced to reflect their lesser value to Manitoba Hydro but still to return the full estimated value of that option to the customer.

Section:	Section 7.2	**Page No.:**	20
Topic:	Generation Allocation		
Subtopic:	Marginal Cost Weights		
Issue:	Impact of Transmission Constraints on Marginal Cost		

PREAMBLE TO IR (IF ANY):

MH uses the relative market value of energy in twelve time periods to weight its energy allocator used to allocate generation costs.

QUESTION:

a) How many hours was the intertie with the US constrained in each of the years 2014 and 2015?

b) Is there a typical pattern to any US intertie constraints, such as only occurring in peak hours or off-peak hours? If so, please describe this pattern.

c) Please provide hourly energy flows on the US intertie for years 2014 and 2015 and mark any hours there was a constraint.

d) After Keeyask and the new intertie are in service, please describe any anticipated changes to intertie constraints.

RATIONALE FOR QUESTION:

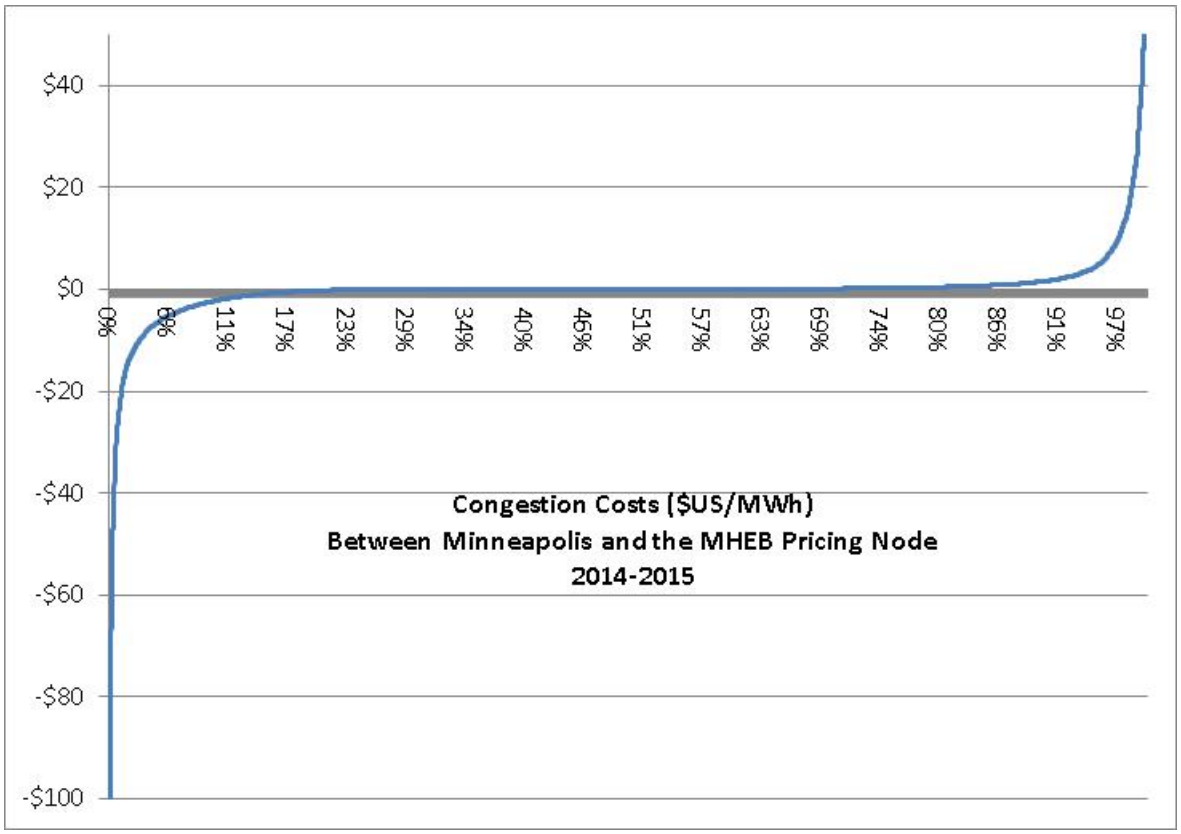
Would like more information to assess significance and reasonableness of MH allocation weights.

RESPONSE:

a) Electricity flows from Manitoba to MISO over the US interconnection reflect the carrying ability of the regional electric grid, not just the carrying capacity of the four actual lines.

Differences in MISO electricity prices can be used to indicate times when there is congestion or constraints on the flow of electricity. When the grid is lightly loaded, losses and congestion are low. When the grid is highly loaded, losses and congestion are high. To the extent that there are losses and congestion, these are reflected in inverse proportion to the prices Manitoba Hydro receives at its MISO MHEB pricing node at the Canada-US border, i.e. when the network is overloaded export prices at the MHEB node will be low relative to prices in Minneapolis. Conversely when the network is lightly loaded export prices at the MHEB node will be quite similar to the prices in Minneapolis.

The following chart indicates the congestion and loss costs between the US border and Minneapolis for 2014 and 2015. The maximum amount of congestion was $691/MWh which occurred when electricity prices were $94/MWh in Minneapolis and -$602/MWh at the Manitoba border.



Based upon this data there was significant congestion of varying degrees on the grid in about 15% of the hours in 2014 and 2015 for a total of about 2600 hours.

b) Congestion in 2014 and 2015 occurred with equal frequency in the on-peak and off-peak periods.

c) Hourly energy flows on the US intertie have been provided in the form of Hourly Net Scheduled Interchange in the attached spreadsheet on the Sheet labeled NSI. The Midcontinent Independent System Operator (MISO) defines Net Scheduled Interchange (NSI) as "The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time." The hourly NSI data provided is for the MHEB Interface in Eastern Standard Time. Positive values represent a net outflow from MHEB to MISO while negative values represent a net inflow from MISO to MHEB. It is important to note that the values provided are a net value and include all flows across the intertie either by Manitoba Hydro or other market participants carrying out transactions to and from MISO. All transactions impact the Real-Time Locational Marginal Price (LMP) at the US intertie.

On the Sheet labeled LMP and MCC Delta, Column L indicates the congestion cost. When this amount is negative there is congestion on the interconnection in that hour that indicates there are transmission constraints in northern MISO that are affecting Manitoba Hydro's ability to export power.

d) Assuming all other things remain equal, it is anticipated that the amount of congestion will decrease once the new intertie is in service. However, the actual reduction is not yet quantifiable as there will inherently be other factors such as load pattern and other generation changes across the region before then.

Section:	Appendix 3.1	**Page No.:**	48
Topic:	External Allocators		
Subtopic:	Data Sources		
Issue:	Use of Eight Years of Data		

PREAMBLE TO IR (IF ANY):

MH relies on eight years of historical data to develop several external allocators for its COSS.

QUESTION:

a) What is the justification for using eight years of price data to develop the weighting factors for the energy allocators instead of just more recent data?

b) How much do the factors used to estimate class demands vary year-to-year?

RATIONALE FOR QUESTION:

Typically see allocators based on load research from one recent year. Older data may be affected by old market conditions and changes in consumption patterns.

RESPONSE:

a) Actual SEP pricing data, which serves as a proxy for energy values in the MISO market, is used to generate pricing differentials that are used to weight energy between time periods. In the short term, market conditions may result in volatility in energy pricing. Manitoba Hydro prefers to select a longer period, in this case eight years of price data adjusted for inflation, to normalize and improve the stability of the energy allocator on a year-over-year basis.

b) Please see Manitoba Hydro's response to PUB/MH I-5 for a table comparing Coincident Peak Load Factors and Coincident Factors for the eight year sample used to estimate class NCP demand.

Section:	Appendix 3.1	**Page No.:**	48
Topic:	External Allocators		
Subtopic:	Data Sources		
Issue:	Use of Eight Years of Data		

PREAMBLE TO IR (IF ANY):

MH relies on eight years of historical data to develop several external allocators for its COSS.

QUESTION:

c) Please provide a copy of all load research reports MH has created in the past eight years, if any.

d) Please provide class non-coincident peak annual load factors and coincidence factors for each of MH's rate classes for each year of the past eight years.

e) Please provide daily average hourly load profiles for each of MH's rate classes for each year of the past eight years

RATIONALE FOR QUESTION:

Typically see allocators based on load research from one recent year. Older data may be affected by old market conditions and changes in consumption patterns.

RESPONSE:

c) The eight years of Load Research at common bus peak, as well as the two years of Load Research at generation peak, used in PCOSS08 (Order 116/08) and PCOSS14-Amended are attached to the response to PUB/MH I-5a-d.

d) The class non-coincident peak annual load factors and coincidence factors for each of the domestic rate classes for each year of the past eight years used in PCOSS08 (Order 116/08) and PCOSS14-Amended are attached to the response to PUB/MH I-5a-d.

e) Hourly load profiles for each of the domestic rate classes for each year of the past eight years used in Load Research supporting PCOSS08 (Order 116/08) and PCOSS14-Amended are provided in the Excel attachment to this response.

Section:	PCOSS14 (Amended)	**Page No.:**	Schedule D5, p. 2
Topic:	Peak Load Data		
Subtopic:	NCP Allocation		
Issue:	Supporting Data		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please define the error or variance in the load research sample used to create the Adjust %'age column.

b) Please provide supporting data and calculations for the "CP Load Factor" and "Class Coinc. Factor" columns. Please provide this data in Microsoft Excel format.

RATIONALE FOR QUESTION:

Load data is available for the 2CP allocator that is based on one year of data. The NCP allocators are based on eight years of data and the supporting data is not provided.

RESPONSE:

a) Variance is derived as the square of the class (Coincident Peak Load kW) * (Relative Accuracy %)/100

   CP Load kW is the average of the hourly class demand estimates corresponding to the TOP 50 generation peak kW hours for winter on-peak (Dec-Feb, 6:00 - 22:00) or summer on-peak (Jun-Aug, 6:00 to 22:00).

   Relative Accuracy is derived as the average of the Percent-Error for each of the hourly class demand estimates corresponding to the TOP 50 generation peak kW hours for winter on-peak (Dec-Feb, 6:00 - 22:00) or summer on-peak (Jun-Aug, 6:00 to 22:00).

Percent-Error is the percentage error (or accuracy) of the estimated demand for the class based on a 90% confidence level. It is a measure of the variability of the sample estimate.

The Percent-Error and Variance are zero for the GSL 30 to 100 kV and GSL > 100 kV classes, as those classes are measured by way of individual metering at each customer location and are not subject to statistical sampling methods.

b) Coincident Peak time is the 50 hours during the on-peak period with the highest system kW demands. The class Coincident Peak (CP) load is the average kW load over these 50 hours.

System peak may be at Common Bus (domestic transmission load) or Generation. In 2011/2012 generation includes hydraulic, gas and coal turbine, wind and imports. In 2005-2006 generation includes hydraulic, gas and coal turbine.

- Winter On-Peak period is December through February, 06:00 to 22:00.
- Summer On-Peak period is June through August, 06:00 to 22:00.
- Overall On-Peak period is defined as January through December, 06:00 to 22:00.
- Study period is 1 year: April 1 – March 31.

Coincidence Factor (CF) is the CP/NCP. NCP is the single class hourly kW peak demand in the study period.

The eight years of Load Research at common bus peak, as well as the two years of Load Research at generation peak, used in PCOSS14-Amended are attached to the response to PUB/MH I-5a-d. Hourly load profiles for each of the domestic rate classes for each year of the past eight years used in Load Research supporting PCOSS14-Amended are attached to the response to PUB/MH I-53c-e.

Section:	Section 7.2	**Page No.:**	20
Topic:	Functionalization of HVDC		
Subtopic:	Bipole III		
Issue:	Impact on COS		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide anticipated cost details for Bipole III in electronic excel format, similar to what was provided for Bipoles I and II in the excel file titled "Specific Cost Details _Bipoles and Dorsey," which was provided March 11. Please provide estimated costs for the first full year Bipole III is in service.

b) Please provide comparable electronic COS models in Excel format, which show the COS calculations and results with and without Bipole III in service.

RATIONALE FOR QUESTION:

Would like data to assess impacts of future large capital assets on COS.

RESPONSE:

Please refer to the summary schedules below as well as the electronic model provided as PUB-MH I-55-att1.xlsx.

The analysis provided assumes the Bipole III and Riel Station revenue requirements as provided in response to PUB/MH I-71e. For cost of service purposes, the Bipole III revenue requirement has been adjusted to exclude the costs related to the Riel 230/500 kV terminal station (AC switchyard). The same caveats discussed in PUB/MH I-71e apply to the cost of service scenario prepared. The scenario provides only directional information regarding RCC

changes but illustrative of alternate methods of functionalizing and classifying the Bipole facilities on class cost responsibility.

In the summary table below, Finance Expense includes Capital Tax and has been reduced by the Amortization of BPIII Reserve. The net amount is included in "Interest" in the cost of service study. To prepare the analysis, the revenue for domestic classes, excluding diesel and SEP customers, has been increased by 19% on an across-the-board basis in order to offset the $266M incremental revenue requirement, and maintain the equivalency of total costs (including Net Income) and revenues in the PCOSS. All costs have been functionalized as Generation.

Bipole III 2020 Revenue Requirement

	2020 ($millions)	**2020 PCOSS ($ millions)**
Finance Expense	228	163
OM&A Costs	12	12
Depreciation	91	91
Amortization of BPIII Reserve	(87)	
Capital Tax	22	
Total Revenue Requirement	266	266

Manitoba Hydro
Prospective Cost Of Service Study
March 31, 2014
Revenue Cost Coverage Analysis
Model of PUB/MH-55
S U M M A R Y

Customer Class	Total Cost ($000)	Class Revenue ($000)	Net Export Revenue ($000)	Total Revenue ($000)	RCC % Current Rates	Cost less NER	Change Cost less NER	Change in RCC	Change in NER
Residential	706,857	702,237	18,463	720,700	102.0%	688,393	98,359.4	2.2%	
General Service - Small Non Demand	149,306	161,097	3,803	164,900	110.4%	145,503	21,055.1	2.4%	
General Service - Small Demand	159,272	162,344	4,055	166,399	104.5%	155,217	25,364.3	0.0%	
General Service - Medium	232,545	222,849	5,962	228,811	98.4%	226,583	38,630.6	-1.0%	
General Service - Large 0 - 30kV	116,791	101,353	2,989	104,342	89.3%	113,802	20,153.7	-2.0%	
General Service - Large 30-100kV*	73,972	68,965	1,921	70,886	95.8%	72,051	14,246.2	-4.2%	
General Service - Large >100kV*	249,509	225,785	6,429	232,214	93.1%	243,080	51,056.6	-5.5%	
*Includes Curtailment Customers									
SEP	968	826	-	826	85.4%	968	-	0.0%	
Area & Roadway Lighting	22,786	25,804	197	26,001	114.1%	22,590	1,012.3	13.9%	
Total General Consumers	1,712,006	1,671,261	43,819	1,715,080	100.2%	1,668,187	269,878.1	0.0%	
Diesel	9,948	6,612	262	6,874	69.1%	9,686	363.7	-3.7%	
Export	301,152	345,233	(44,081)	301,152	100.0%				(47,081.9)
Total System	2,023,106	2,023,106	-	2,023,106	100.0%				

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2014
Customer, Demand, Energy Cost Analysis
Model of PUB/MH-55
SUMMARY

	CUSTOMER			DEMAND					ENERGY			
Class	Cost ($000)	Number of Customers	Unit Cost $/Month	Cost ($000)	% Recovery	Billable Demand MVA	Unit Cost $/KVA		Cost ($000)	Metered Energy mWh	Unit Cost ¢/kWh	
Residential	125,495	486,987	21.47	185,857	0%	n/a	n/a		377,041	7,404,453	7.60	**
GS Small - Non Demand	24,993	53,778	38.73	35,103	0%	n/a	n/a		85,407	1,605,511	7.51	**
GS Small - Demand	8,492	12,492	56.65	40,740	38%	2,390	6.46		105,985	2,047,715	6.41	
General Service - Medium	7,427	1,974	313.52	58,139	87%	7,302	6.96		161,017	3,174,662	5.30	
General Service - Large <30kV	3,736	288	n/a	25,119	100%	4,042	7.14	*	84,947	1,702,481	4.99	
General Service - Large 30-100kV	2,582	40	n/a	9,383	100%	2,894	4.13	*	60,087	1,327,210	4.53	
General Service - Large >100kV	2,385	16	n/a	20,473	100%	8,409	2.72	*	220,222	4,903,742	4.49	
SEP	326	29	935.95	132	0%	n/a	n/a		509	26,500	2.42	**
Area & Roadway Lighting	16,620	155,024	8.93	2,196	0%	n/a	n/a		3,774	100,487	5.94	**
Total General Consumers	192,056	710,628		377,143		25,038			1,098,988	22,292,761		
Diesel	229	755	25.23	343	0%	n/a	n/a		9,114	13,754	68.76	**
Export	n/a	n/a	n/a	21,172	0%	n/a	n/a		279,979	9,013,000	3.34	***
Total System	192,284	711,383		398,658		25,038			1,388,082	31,319,515		

* - includes recovery of customer costs
** - includes recovery of demand costs
*** -includes recovery of customer and demand costs

Manitoba Hydro
Prospective Cost Of Service Study - March 31, 2014
Functional Breakdown
Model of PUB/MH-55
S U M M A R Y

Class	Total Cost ($000)	Generation Cost ($000)	%	Transmission Cost ($000)	%	Subtransmission Cost ($000)	%	Distribution Cust Service Cost ($000)	%	Distribution Plant Cost ($000)	%
Residential	688,393	375,708	54.6%	48,488	7.0%	32,217	4.7%	69,277	10.1%	162,703	23.6%
General Service - Small Non Demand	145,503	85,118	58.5%	10,355	7.1%	5,816	4.0%	17,606	12.1%	26,609	18.3%
General Service - Small Demand	155,217	105,623	68.0%	12,259	7.9%	6,700	4.3%	4,207	2.7%	26,429	17.0%
General Service - Medium	226,583	160,461	70.8%	18,817	8.3%	9,263	4.1%	6,403	2.8%	31,639	14.0%
General Service - Large <30kV	113,802	84,654	74.4%	9,727	8.5%	4,631	4.1%	3,512	3.1%	11,279	9.9%
General Service - Large 30-100kV	72,051	59,874	83.1%	6,058	8.4%	3,536	4.9%	2,513	3.5%	69	0.1%
General Service - Large >100kV	243,080	219,450	90.3%	21,245	8.7%	0	0.0%	2,357	1.0%	29	0.0%
SEP	968	509	52.6%	132	13.7%	0	0.0%	309	31.9%	17	1.7%
Area & Roadway Lighting	22,590	3,829	16.9%	326	1.4%	447	2.0%	543	2.4%	17,446	77.2%
Total General Consumers	1,668,187	1,095,226	65.7%	127,407	7.6%	62,609	3.8%	106,725	6.4%	276,219	16.6%
Diesel	9,686	9,114	94.1%	0	0.0%	0	0.0%	0	0.0%	571	5.9%
Export	301,152	279,230	92.7%	21,922	7.3%	0	0.0%	0	0.0%	0	0.0%
Total System	1,979,024	1,383,570	69.9%	149,330	7.5%	62,609	3.2%	106,725	5.4%	276,791	14.0%

Section:	Electronic Model	**Page No.:**	N/A
Topic:	Generation costs		
Subtopic:	Generation asset pools		
Issue:	Costs of individual hydro dams		

PREAMBLE TO IR (IF ANY):

The electronic model provides detailed costs of Brandon CT and GS and Selkirk GS but does not provide similar cost detail for individual hydro dams.

QUESTION:

Please provide detailed cost data for each individual hydro generating station in MH's system similar to what was provided for the thermal generating stations. Please provide this data in electronic Excel format.

RATIONALE FOR QUESTION:

Provides additional data to assess variance in asset pools for allocation purposes.

RESPONSE:

Cost details provided below are the direct costs of the generating stations only, and do not include the additional allocation of common generation costs such as mitigation, water management, town-sites, HVDC transmission facilities, research and development, marketing, power resource planning, generation-related transmission or a share of Interest on communication facilities, administrative buildings and general equipment.

The Excel version of this data is provided as PUB-MH I-56-att1.xlsx

		2013-2014 Average Rate Base	Finance Expense	2014 Net Book Value	Capital Tax	Total Interest Expense	Depreciation	Operating	Total Cost
Burntwood	Wuskwatim GS	1,352,956,322	59,912,725	1,342,438,797	7,749,689	67,662,415	23,456,018	9,516,886	100,635,318
Laurie River	Laurie River GS	14,515,875	642,804	15,234,363	87,946	730,750	994,570	1,254,776	2,980,095
Lower Nelson	Long Spruce GS	262,814,400	11,638,164	260,882,928	1,506,036	13,144,200	8,784,351	32,556,217	54,484,768
Lower Nelson	Kettle GS	237,043,249	10,496,944	240,679,434	1,389,405	11,886,349	6,767,458	33,781,270	52,435,076
Lower Nelson	Limestone GS	968,609,326	42,892,755	958,575,787	5,533,708	48,426,463	23,507,680	38,118,576	110,052,720
Saskatchewan River	Grand Rapids GS	244,247,634	10,815,975	244,642,153	1,412,281	12,228,256	7,287,436	17,446,151	36,961,843
Upper Nelson	Jenpeg GS	138,531,222	6,134,554	137,451,621	793,487	6,928,040	5,092,956	14,302,740	26,323,737
Upper Nelson	Kelsey GS	293,688,718	13,005,366	309,542,556	1,786,941	14,792,306	7,047,543	15,002,223	36,842,073
Winnipeg River	Great Falls GS	94,672,533	4,192,367	114,859,151	663,064	4,855,431	3,962,732	11,939,771	20,757,934
Winnipeg River	McArthur Falls GS	21,992,019	973,869	23,096,902	133,335	1,107,203	1,005,321	4,471,786	6,584,310
Winnipeg River	Seven Sisters GS	76,865,545	3,403,823	77,111,447	445,152	3,848,976	2,526,286	8,375,324	14,750,585
Winnipeg River	Pine Falls GS	32,962,172	1,459,658	34,242,514	197,677	1,657,335	1,368,660	5,772,643	8,798,638
Winnipeg River	Pointe Du Bois GS	304,978,711	13,505,318	554,430,352	3,200,640	16,705,958	5,034,148	13,103,891	34,843,997
Winnipeg River	Slave Falls GS	118,138,281	5,231,497	121,552,665	701,705	5,933,201	3,307,054	6,330,042	15,570,297
Thermal	Brandon GS*	42,371,784	1,876,342	39,559,317	228,370	2,285,590	8,894,100	18,060,177	29,239,867
Thermal	Selkirk GS*	51,769,713	2,292,509	51,838,505	299,256	2,335,060	2,652,795	12,777,136	17,764,991
Thermal	Brandon CT*	104,247,382	4,616,368	100,726,056	581,476	5,273,670	6,969,313	2,314,928	14,557,911

*Total Thermal Generation Interest pro-rated between stations on Gross Investment consistent with Interest calculated for 'Allocated Costs' in model

Section:	Appendix 3.1	**Page No.:**	Schedules E10-E12, E14, E18-E19
Topic:	Customer Allocators		
Subtopic:	Weighting Factors		
Issue:	Vintage of Analysis		

PREAMBLE TO IR (IF ANY):

Several customer allocators weight the number of customers in each class based on MH analyses.

QUESTION:

For each of the schedules referenced in the table above:

a) Please provide the time period the analysis used to estimate the weighting factors was performed.

b) Is there a need to update any of these analyses? If so, when will they be updated? If not, why not?

RATIONALE FOR QUESTION:

Wish to confirm whether the analysis used to estimate the customer weights is reasonable.

RESPONSE:

The weights for the C10 Customer Service General allocator were last updated for PCOSS11, and C14 Electrical Inspections allocators were updated for PCOSS14.

Weights used for C11 Billing, C12 Collections, C40 Meter Investment and C41 Meter Maintenance are based on analysis conducted in 1991. Manitoba Hydro does not expect revised weights will have a material impact on COSS results, but acknowledges that due to the age of the study it is appropriate to update weights and will do so as resources are available.

Section:	Appendix 3.1	**Page No.:**	Schedule E17
Topic:	Customer Allocators		
Subtopic:	Weighting Factors		
Issue:	Service Drops per Customer		

PREAMBLE TO IR (IF ANY):

The customer allocator for service drops weights GSS 3 phase, GSM, and GSL customers with a factor of 5.

QUESTION:

a) What is the basis for the 5x weighting factor?

b) Has MH analyzed the number of service drops feeding more than one meter for each rate class? If so, what were the results of this analysis? If not, why not?

RATIONALE FOR QUESTION:

Wish to confirm whether the analysis used to estimate the customer weights is reasonable.

RESPONSE:

The 5x weighting factor used in COSS since at least 1991 recognizes higher service drop costs associated with the size of these customers. Manitoba Hydro notes that service drops represent 0.4% of revenue requirement; any change to the weights is expected to have little to negligible RCC impacts. MH will update supporting analysis where cost effective and as resources allow.

Section:	Appendix 3.1	**Page No.:**	11-12
Topic:	DSM Costs		
Subtopic:	Allocation of DSM Costs		
Issue:	Basis of Allocation		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro has proposed to assign DSM costs directly to the amount of dollars spent on each specific customer class.

QUESTION:

a) Please list, describe, and discuss Manitoba Hydro's reasons for not selecting other options being considered by Manitoba Hydro, by Christensen Associates in its reports prepared for Manitoba Hydro, and by NERA in reports delivered in work associated with Manitoba since 2004 for the allocation of net export revenue.

RATIONALE FOR QUESTION:

Other utilities, recognize that the benefits of a DSM extend beyond the specific class for which the money has been spent.

RESPONSE:

Manitoba Hydro presumes based on the topic and preamble that the question was meant to refer to the allocation of DSM costs, and not net export revenue as stated in the question. NERA did not provide any recommendations with regards to the allocation of DSM costs.

In their 2012 report, Christensen Associates stated that it was inappropriate to assign the costs of DSM directly against the Export Class, and recommended that the costs should be assigned to the domestic rate class which they end up benefitting (Appendix 5, pages 26 and 27). This is expanded upon in Manitoba Hydro's response to PUB/MH I-16b:

"PCOSS is comprised of embedded financial cost. These costs have to be assigned or allocated to the respective customer groups. The PCOSS methodology, as well as the industry standard, to accomplish this division into customer groups is based upon cost causation, not product value. DSM program costs are incurred for specific customer groups in order to enable the customers within these groups to become more efficient and benefit from lower energy bills than they would otherwise incur. It is true that if DSM results in "freed-up" energy which can be sold on the Export market above cost that there will be value for the MH system. (This is why the DSM programs are screened accordingly.) However, costs are allocated based upon cost causation, not value. CA Energy Consulting's position is not that Export sales cannot influence the value to the MH system of DSM, but simply that DSM costs should be allocated in PCOSS to the Domestic rate groups which cause each program's costs."

Manitoba Hydro agrees with CA's perspective and rationale for the treatment of DSM costs which it assigns to domestic customers based on class participation. DSM is undertaken to meet Manitoba load reliably and at least cost. It is true that DSM programs reduce the overall cost of the system for domestic customers by deferring generation investment as well as transmission and distribution investment. And while it may be tempting to develop a cost allocation methodology on this basis, Manitoba Hydro believes that the direct assignment approach is not only fair, but a superior approach for the following reasons:

1) There is a reasonable case that DSM is a substitute for generation, transmission and distribution resources. However, the effect of DSM on class use of these resources is not necessarily aligned with the class share of the total cost of these resources.

2) Timing of the rollout of DSM programming can favour some classes over others through significantly reduced usage (and hence, reduced cost responsibility in the PCOSS) while other classes, with few or no programs, are allocated responsibility for DSM cost if it is treated as a Generation resource in the PCOSS. In the long run, it is expected that DSM (costs and benefits) would be more evenly distributed among classes but in the short run, such incidence can distort the results of the PCOSS.

Section:	Appendix 3.1	**Page No.:**	11-12
Topic:	DSM Costs		
Subtopic:	Allocation of DSM Costs		
Issue:	Basis of Allocation		

PREAMBLE TO IR (IF ANY):

Manitoba Hydro has proposed to assign DSM costs directly to the amount of dollars spent on each specific customer class.

QUESTION:

b) Please provide any reports, presentations, memoranda and spreadsheet analyses that were prepared as part the economic justification of DSM expenditures.

RATIONALE FOR QUESTION:

Other utilities, recognize that the benefits of a DSM extend beyond the specific class for which the money has been spent.

RESPONSE:

The economic justification of the current DSM plan is outlined in the attached 2015/16 Power Smart Plan - 15-year Supplement Report. The economic justification of the DSM plan used in the PCOSS14 is outlined in the attached 2012/13 Power Smart Plan - Working Document.

Power Smart Plan

2015/16

SUPPLEMENTAL REPORT:

15yr (2015 to 2030)

OCT-2015

Manitoba Hydro
POWER SMART

EXECUTIVE SUMMARY

Manitoba Hydro's 2015 Power Smart Plan (Supplemental Report) outlines the Corporation's demand side management program over the next 15 years, with some programs formally approved and placeholders used for those opportunities requiring further review and analysis. This plan builds upon and is consistent with the one year 2015/16 Power Smart Plan which was prepared in consultation with the Minister responsible for Manitoba Hydro. The longer term 15 year plan was developed to accommodate the Corporation's business planning requirements, including the development of an integrated resource plan. In addition and more importantly, Manitoba Hydro's Power Smart Plan involves taking a long term strategic approach; focusing on the transformation of markets and optimization of demand side management activities. The one year plan is simply the activity within the immediate future, however it is integral to the longer term strategy and plan.

This report outlines the 15 year forecast of energy and demand savings, investments and cost effectiveness metrics to the benchmark year of 2029/30 which will be targeted through electricity and natural gas Power Smart Programs. The plan sets out to realize electricity savings of 1,288 MW and 4,619 GW.h, natural gas savings of 118 million cubic metres and combined global greenhouse gas emission reductions of 3.3 million tonnes by 2029/30. This activity represents 16.0% of the estimated electric load forecast offsetting 60% of projected load growth during this period and 6.9% of the estimated natural gas volume forecast by 2029/30, further reducing natural gas consumption in Manitoba. Manitoba Hydro's current 15 year DSM plan involves an investment of approximately $2.6 billion (utility investment of $1.4 billion and customer investment of an estimated $1.2 billion, excluding cost impacts of changes to codes and standards). Of the $1.4 billion utility investment, $1.2 billion of the costs are funded through the Corporation's Power Smart electricity budget, $138 million from the Power Smart natural gas budget, $6 million from the Affordable Energy Fund and $20 million from the Furnace Replacement budget for targeting furnace replacement.

Changes made to the electricity component of the plan include adjustments to existing programs to reflect updated information and the inclusion of emerging technologies with programming starting around 2020. The addition of emerging technologies offers the most significant change to the overall plan, however the inclusion of this category of energy savings assumes and is dependent upon future projected cost reductions. As such, this category of energy savings inherently involves a higher risk than most other DSM programs. Other categories which will present a higher risk of DSM deliverability include Conservation Rates, Fuel Choice and Load Displacement. Conservation Rates require additional approval levels in the regulatory arena; the Fuel Choice initiative must consider the Province of Manitoba's Clean Energy Strategy; and the Load Displacement Program requires the participation of a few customers, who are often influenced by a number of factors such as capital prioritization between projects, changes in the economy, etc. No significant changes were made to the natural gas component of the plan.

Combined with energy savings achieved to date, total electrical savings of 1,863 MW and 7,233 GW.h and total natural gas savings of 219 million cubic metres will be realized by 2029/30. These combined energy savings are expected to result in an overall reduction of greenhouse gas emissions of 5.3 million tonnes by 2029/30. This activity represents 25.0% of the estimated electric load forecast and 12.8% of the estimated natural gas volume forecast by 2029/30.

Including investments to date, it is expected that by 2029/30, the cumulative investment of achieving the energy savings will have been $3.4 billion (utility investment of $2.0 billion and customer investment of an estimated $1.4 billion, excluding cost impacts of changes to codes and standards). Of the $2.0 billion cumulative utility investment, $1.7 billion of the costs are funded through the Corporation's Power Smart electricity budget, $239 million from the Power Smart natural gas budget, $35 million from the Affordable Energy Fund, $31 million from the Furnace Replacement budget for targeting furnace replacement.

By reducing electricity and natural gas consumption through innovative products, participating customers can expect to save $338 million in 2029/30 and $2.5 billion cumulatively by 2029/30. When combined with bill reductions to date, Power Smart programs are expected to save participating customers $ 455 million in 2029/30 and over $ 5.3 billion cumulatively by 2029/30.

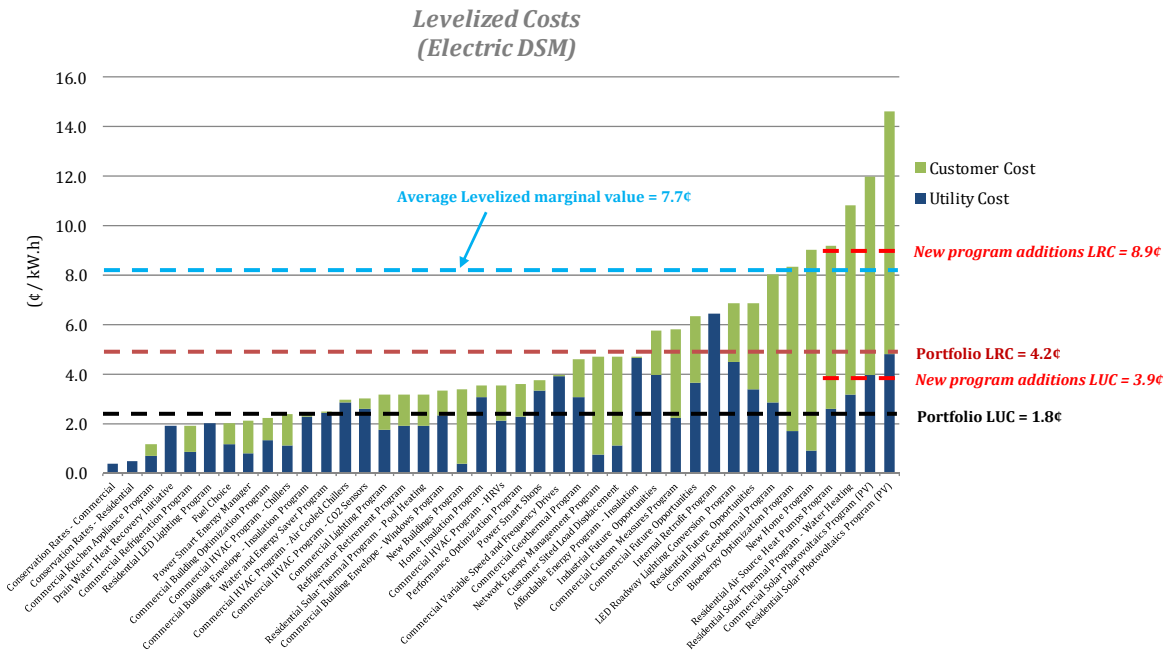
The overall Societal Cost (SC) and Total Resource Cost (TRC) metrics for the electric and natural gas Power Smart portfolio is 2.4 and 2.1, respectively. The electric Power Smart portfolio has an overall TRC of 2.3, Rate Impact Measure (RIM) of 1.0, levelized resource cost of 4.2 cents per kilowatt-hour and levelized utility cost of 1.8 cents per kilowatt-hour. The natural gas Power Smart portfolio has an overall TRC of 1.0, RIM of 0.6, levelized resource cost of 31.4 cents per cubic metre and levelized utility cost of 16.2 cents per cubic metre. Excluding the Affordable Energy Program, the natural gas Power Smart portfolio has an overall levelized utility cost of 10.8 cents per cubic metre.

Manitoba Hydro continues to pursue all cost effective opportunities in its efforts to assist customers with managing their energy bills while balancing the Corporation's efforts to be aligned with the Government's climate change objectives. For electric savings, DSM opportunities are measured against Manitoba Hydro's marginal value of energy which has an average levelized value of 7.7 cents per kilowatt-hour. By taking this approach, Manitoba Hydro's overall electric DSM efforts will result in customers (in aggregate) having lower costs for meeting their electricity needs. Although the average levelized average resource and utility costs of the Manitoba Hydro's electric Power Smart plan are 4.2 cents per kilowatt-hour and 1.8 cents per kilowatt-hour respectively, new programs and opportunities generally involve higher costs. For example, the emerging technologies opportunities being added to this year's plan involve an average levelized resource cost of 8.9 cents per kilowatt-hour and an average levelized utility cost of 3.9 cents per kilowatt-hour.

With natural gas DSM, Manitoba Hydro benchmarks the levelized resource cost against the alternative option of customers not pursuing DSM opportunities and instead purchasing natural gas from neighbouring regions. This alternative levelized value is currently 24.6 cents per cubic metre. With Manitoba Hydro's natural gas DSM plans involving an average levelized resource cost of 31.4 cents per cubic metre, it is recognized that customers' costs are higher by taking such an aggressive approach with natural gas conservation efforts. This aggressive approach effectively values carbon at $35.7 per tonne (i.e. the difference between the alternative cost of purchasing gas and Manitoba Hydro's levelized cost of natural gas DSM). This approach is considered reasonable as it balances the Corporation's objectives of assisting customers with managing their energy bills and while aligning these efforts with the Government's climate change objectives.

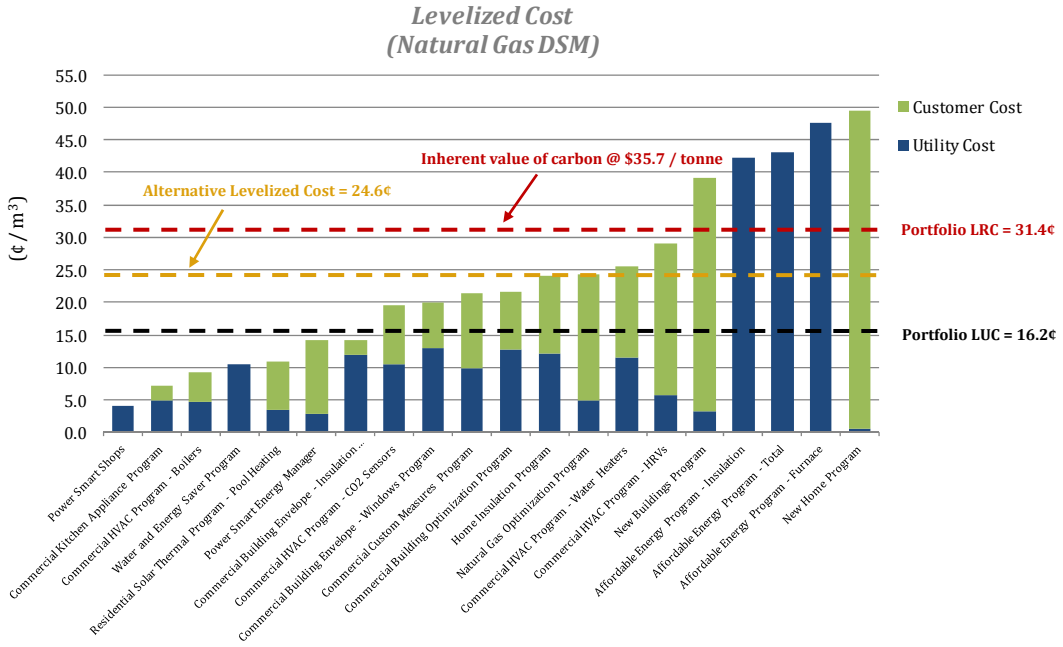
Electric DSM Levelized Costs

The following chart depicts the levelized costs of Manitoba Hydro's electric DSM portfolio.



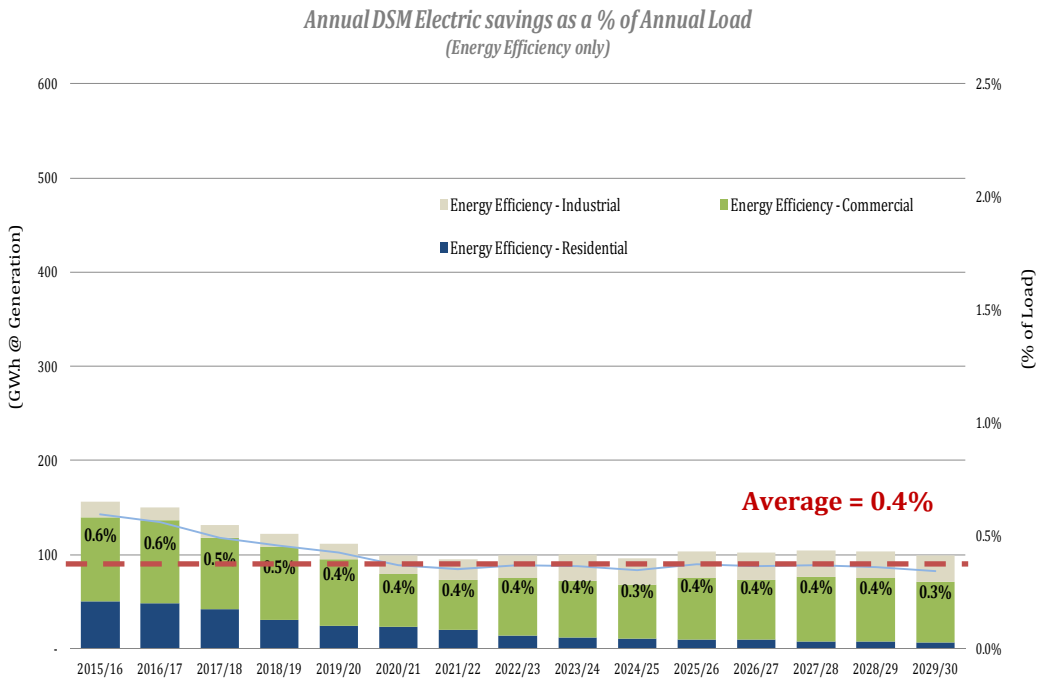
Natural Gas DSM Levelized Costs

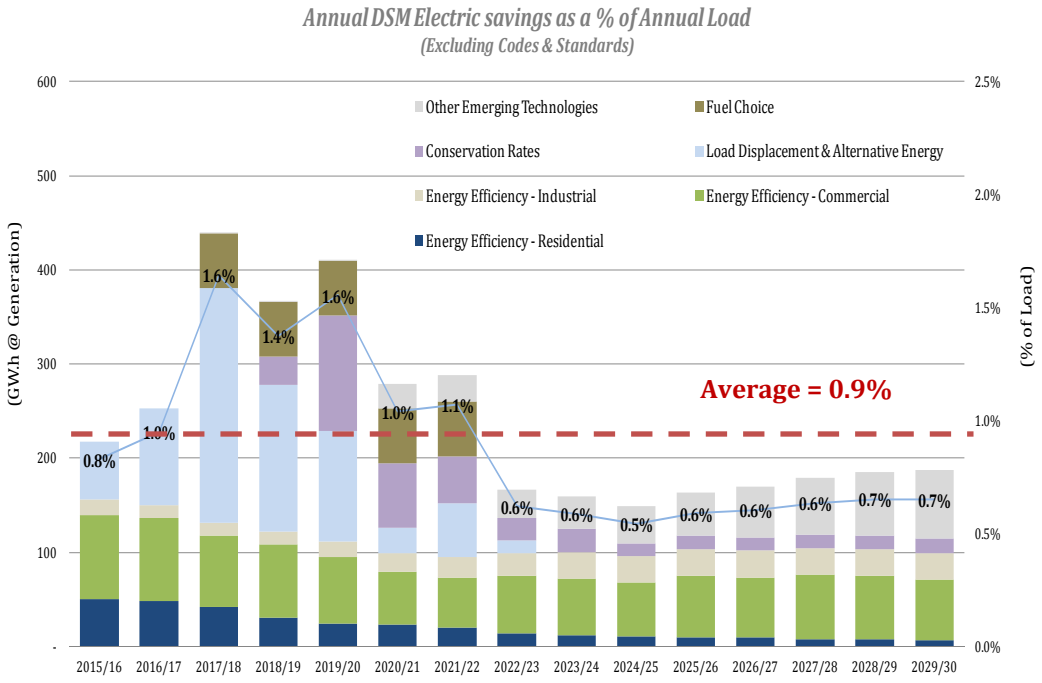
The following chart depicts the levelized costs of Manitoba Hydro's natural gas DSM portfolio.

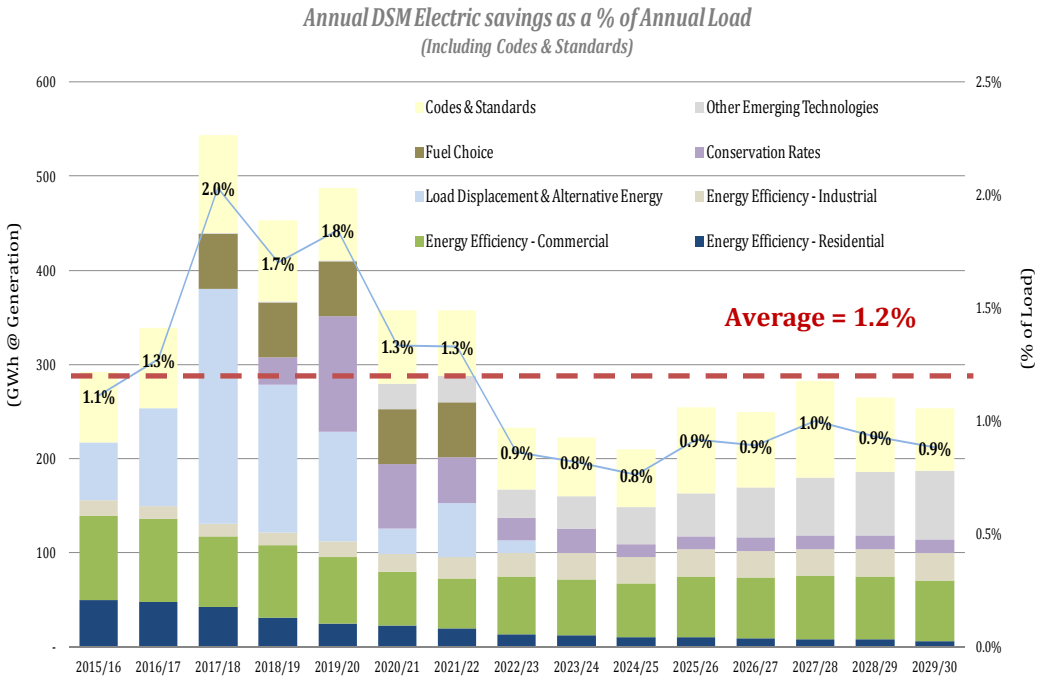


Annual Electric DSM Savings as a % of Annual Load

The following charts depict Manitoba Hydro's annual electric DSM efforts in relation to annual electric load growth.

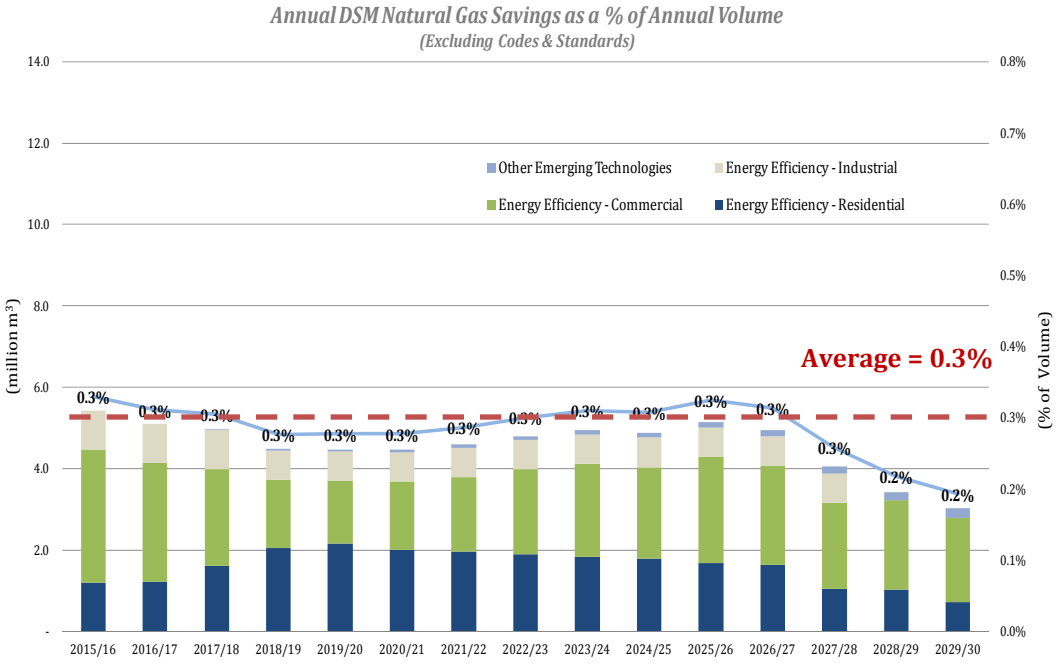


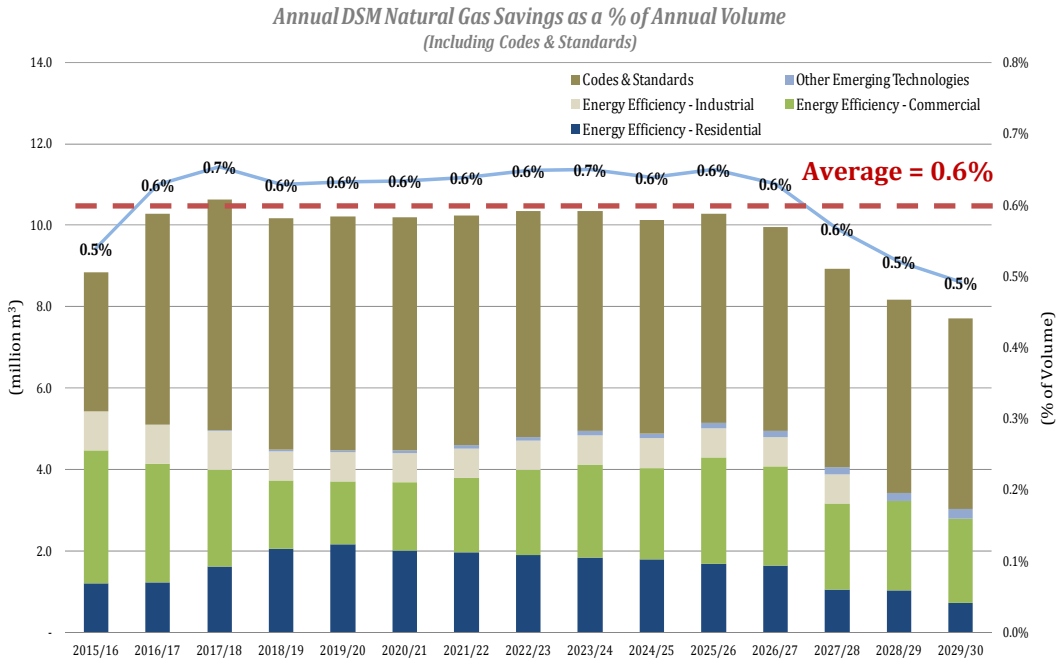


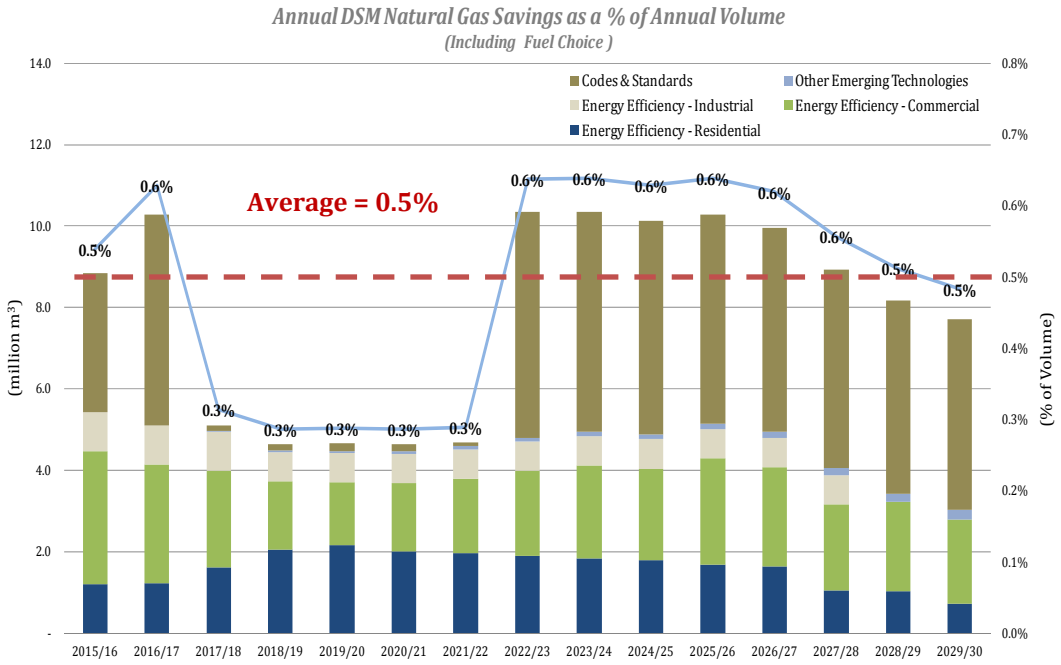

Annual DSM Electric savings as a % of Annual Load
(Including Codes & Standards)
Codes & Standards
Other Emerging Technologies
Fuel Choice
Conservation Rates
Load Displacement & Alternative Energy
Energy Efficiency - Industrial
Energy Efficiency - Commercial
Energy Efficiency - Residential
Average = 1.2%
(GW.h @ Generation)
(% of Load)
600
500
400
300
200
100
-
2.5%
2.0%
1.5%
1.0%
0.5%
0.0%
1.1%
1.3%
2.0%
1.7%
1.8%
1.3%
1.3%
0.9%
0.8%
0.8%
0.9%
0.9%
1.0%
0.9%
0.9%
2015/16
2016/17
2017/18
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
2024/25
2025/26
2026/27
2027/28
2028/29
2029/30

Annual Natural Gas DSM Savings as a % of Annual Volume

The following charts depict Manitoba Hydro's annual natural gas DSM efforts in relation to annual natural gas volume growth.





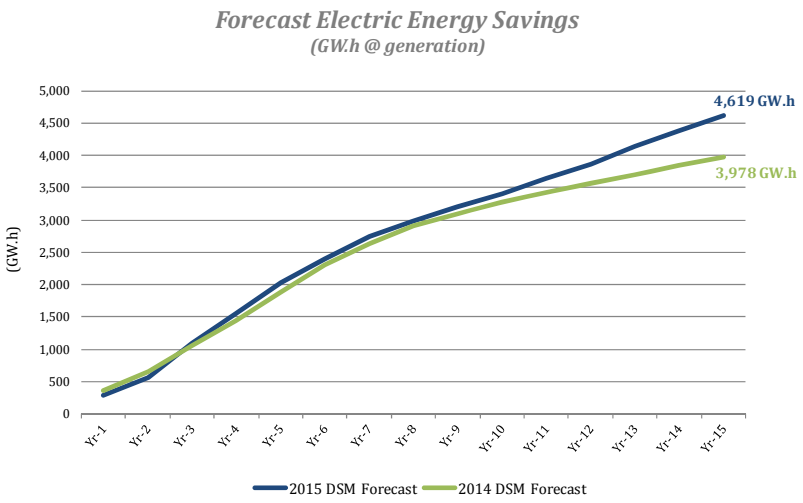


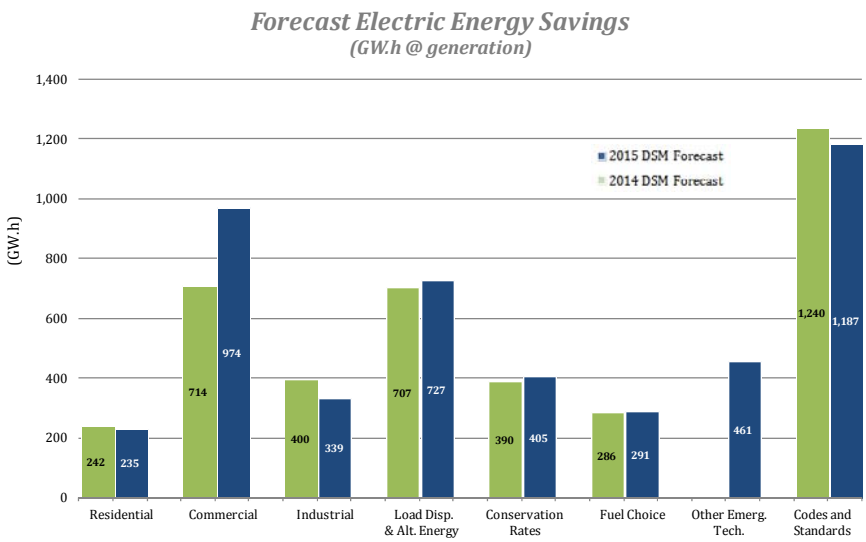
Note: The above graphs reflect a percentage of volume calculation that excludes the natural gas consumption of both Manitoba Hydro Power Stations and Special Contracts in the volume forecast.

Changes from the 2014-17 Power Smart Plan (Supplemental Report 15 yr)

Electric DSM

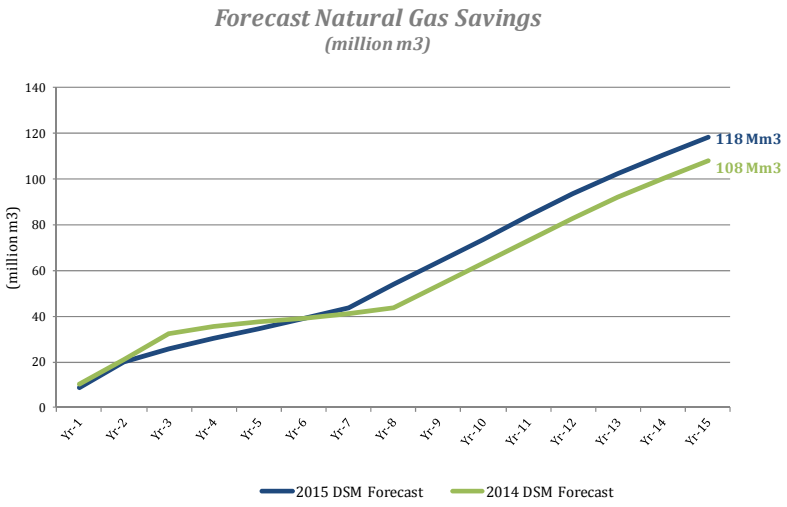
Overall, energy savings are expected to increase by 16% from the 2014 DSM Forecast. The planned electric energy savings in this plan are approximately 641 GW.h higher than previously forecast in the 2014-2017 Power Smart Plan. *(Refer to section 1.6 Comparison to 2014 DSM Forecast for detail).*

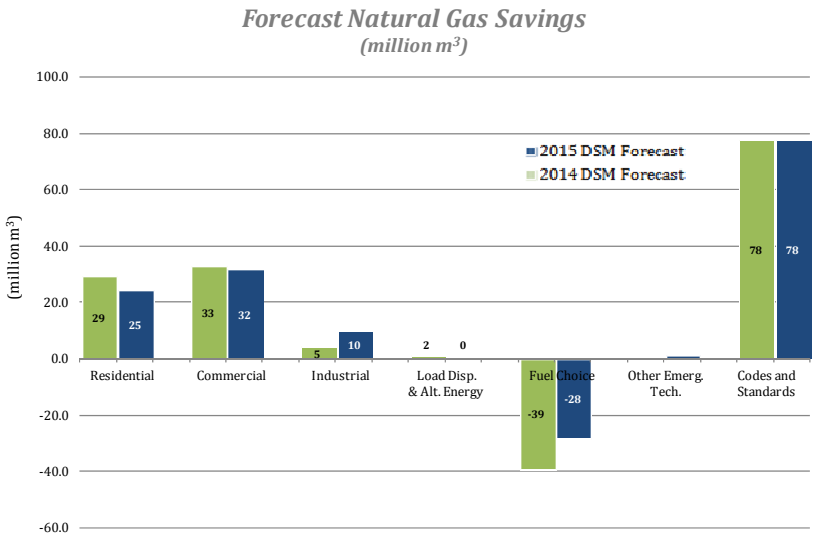




Natural Gas DSM

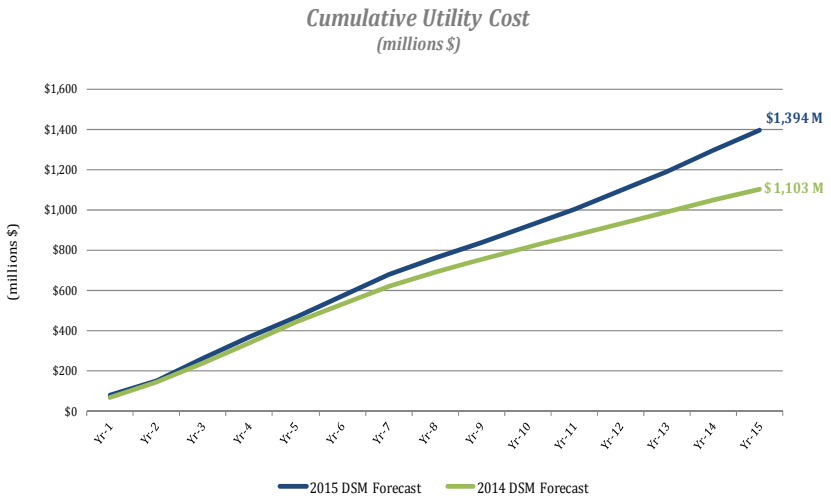
Overall, natural gas savings are expected to increase by 9% from the 2014 DSM Forecast. The natural gas savings expected to be achieved through this plan are 10 million cubic metres higher than previously forecast in the 2014-15 Power Smart Plan. *(Refer to section 1.6 Comparison to 2014 DSM Forecast for detail).*

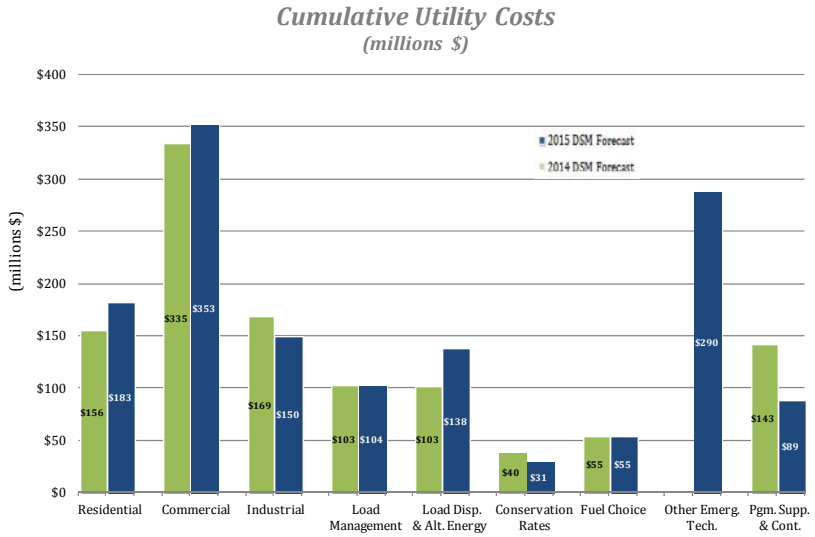




Utility Costs

Overall, utility costs are expected to increase by 26% from the 2014 DSM Forecast. The planned utility cost forecast in this plan is approximately $291 million higher than previously forecast in the 2014-2017 Power Smart Plan. *(Refer to section 1.6 Comparison to 2014 DSM Forecast for detail).*





EXECUTIVE SUMMARY I

1 THE 2015 POWER SMART PLAN 1

1.1 Introduction 1

1.2 DSM Market Transformation Strategy 3

1.3 Power Smart Programs 7

1.4 Risk Analysis 8

1.4.1 DSM Risks 8

1.4.2 Past DSM Performance 11

1.4.3 Risk Management 13

1.5 Economic Assumptions 16

1.6 Comparison to 2014 DSM Forecast 18

2 DEMAND SIDE MANAGEMENT 21

2.1 DSM Targets 21

2.1.1 Electric and Natural Gas DSM Savings 21

2.1.2 Other Fuel Savings 28

2.1.3 Energy Efficient Codes, Standards & Regulation Savings 29

2.2 DSM Investment 45

2.2.1 Total Investment 45

2.2.2 Utility Investment 46

2.2.3 Additional External Sources 52

2.3 DSM Metrics and other related measurements 53

2.3.1 Integrated Perspective 53

2.3.2 Utility Perspective 57

2.3.3 Customer Perspective 59

APPENDIX A – 2015 Power Smart Plan Electric
Appendix A.1 - Annual Capacity Savings (MW)
Appendix A.2 - Annual Energy Savings (GW.h)
Appendix A.3 - Annual Utility Costs
Appendix A.4 - Annual Program Administration Costs
Appendix A.5 - Annual Program Incentive Costs

APPENDIX B - Historical Electric Savings & Costs
Appendix B.1 - Annual Capacity Savings (MW)
Appendix B.2 - Annual Energy Savings (GW.h)
Appendix B.3 - Annual Utility Costs
Appendix B.4 - Annual Program Administration Costs
Appendix B.5 - Annual Program Incentive Costs

APPENDIX C - 2015 Power Smart Plan Natural Gas
Appendix C.1 - Annual Energy Savings (million m^3)
Appendix C.2 - Annual Utility Costs
Appendix C.3 - Annual Program Administration Costs
Appendix C.4 - Annual Program Incentive Costs

APPENDIX D - Historical Natural Gas Savings & Costs
Appendix D.1 - Annual Energy Savings (million m^3)
Appendix D.2 - Annual Utility Costs
Appendix D.3 - Annual Program Administration Costs
Appendix D.4 - Annual Program Incentive Costs

APPENDIX E - Program Evaluation Criteria
Nature of Electricity and Natural Gas Markets
Program Categories
Economic Effectiveness Metrics
Other DSM Program Assumptions

1 THE 2015 POWER SMART PLAN

1.1 Introduction

Manitoba Hydro's 2015 Power Smart Plan outlines the Corporation's demand side management program over the next 15 years, with some programs formally approved and placeholders used for those programs requiring further review and analysis. The Plan was developed through an intensive planning process which builds on the Corporation's experience and continuous involvement in demand side management since 1989. This plan builds upon and is consistent with the 2015/16 Power Smart Plan which was prepared in consultation with the Minister responsible for Manitoba in accordance with the Energy Savings Act. The 15 year plan is required to accommodate the Corporation's overall longer term business planning requirements, including developing an integrated resource plan.

Manitoba Hydro's DSM plan is an input to the development of the Corporation's Integrated Power Resource Plan. To support this process, the Corporation prepares a 15 year forecast which is reviewed and updated annually to reflect current market information and trends. This supplemental report outlines the 15 year forecast underpinning the approved 2015/16 Power Smart Plan and includes the long term forecasts of energy and demand savings, budgets and cost effectiveness metrics.

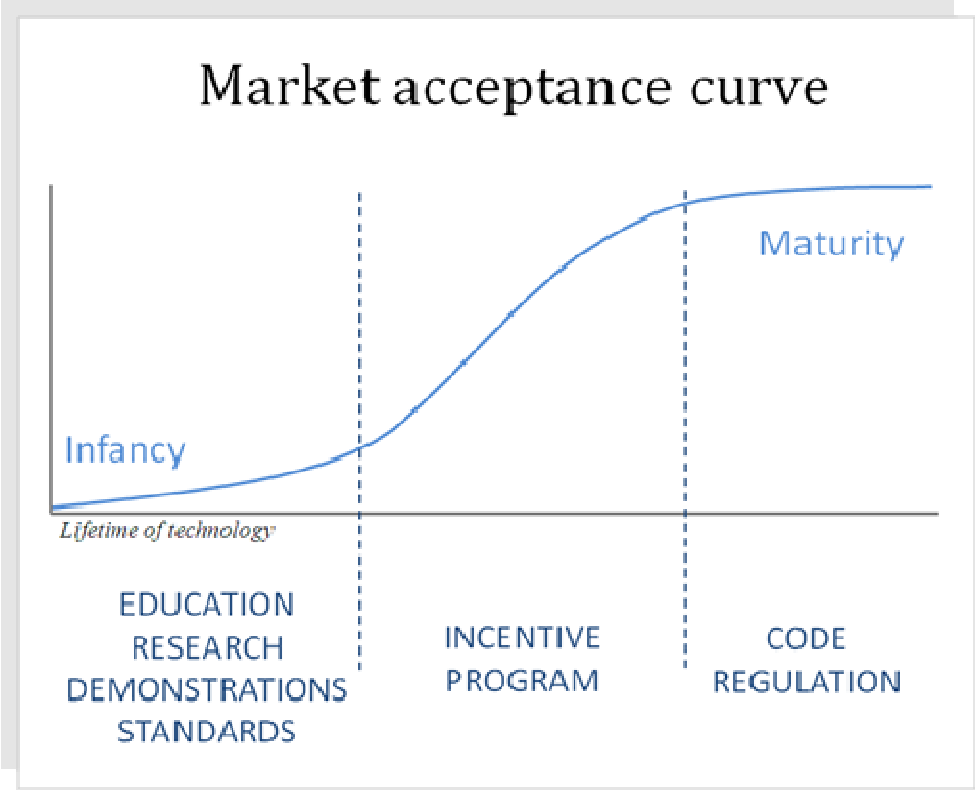
The following table outlines the forecasted achievements of over the next 15 years:

Programs	Capacity Savings (MW)	Energy Savings (GW.h)	Natural Gas Savings (million m^3)	Utility Investment (Millions $)
New Home Program	8.4	19.2	5.4	$3.0
Home Insulation Program	16.0	32.1	7.2	$31.5
Water and Energy Saver Program	3.0	16.5	1.6	$6.5
Affordable Energy Program	14.6	44.3	6.2	$98.0
Refrigerator Retirement Program	1.7	16.6	-	$11.3
Drain Water Heat Recovery Initiative	0.3	1.9	-	$0.6
Residential LED Lighting Program	3.5	11.0	-	$4.7
Community Geothermal Program	32.1	64.3	-	$27.8
Power Smart Residential Loan	3.7	7.3	3.9	-
Power Smart PAYS Financing	1.7	3.5	0.0	-
Residential Earth Power Loan	9.1	18.2	1.4	-
Residential Programs	**94.0**	**234.9**	**25.8**	**$183.4**
Commercial Lighting Program	112.9	436.1	-	$109.6
LED Roadway Lighting Conversion Program	8.8	59.3	-	$56.2
Commercial Building Envelope - Windows Program	14.5	29.7	4.0	$19.3
Commercial Building Envelope - Insulation Program	14.8	32.3	13.0	$37.5
Commercial Geothermal Program	43.5	87.1	-	$44.3
Commercial HVAC Program - Boilers	-	-	5.6	$3.5
Commercial HVAC Program - Chillers	-	9.9	-	$1.8
Commercial HVAC Program - CO2 Sensors	2.0	3.2	1.0	$2.7
Commercial HVAC Program - HRVs	5.7	11.6	2.9	$6.0
Commercial HVAC Program - Air Cooled Chillers	-	15.6	-	$6.9
Commercial HVAC Program - Water Heaters	-	-	1.3	$1.7
Commercial Custom Measures Program	6.8	29.5	1.9	$13.7
Commercial Building Optimization Program	4.4	21.8	4.9	$9.9
New Buildings Program	44.6	149.9	4.1	$20.3
Commercial Refrigeration Program	8.4	66.0	-	$9.7
Commercial Kitchen Appliance Program	0.4	2.0	0.7	$0.7
Network Energy Management Program	0.4	3.8	-	$0.5
Internal Retrofit Program	2.4	7.7	-	$6.4
Power Smart Energy Manager	1.0	4.6	0.4	$0.6
Power Smart Shops	1.0	3.9	0.1	$2.1
Power Smart for Business PAYS Financing	-	-	-	-
Commercial Programs	**271.7**	**973.9**	**39.8**	**$353.4**
Performance Optimization Program	42.6	338.7	-	$144.4
Natural Gas Optimization Program			10.1	$6.0
Indutrial Programs	**42.6**	**338.7**	**10.1**	**$150.4**
Energy Efficiency Subtotal	**408.4**	**1,547.4**	**75.7**	**$687.2**
Curtailable Rate Program	157.8		-	$103.5
Load Management	**157.8**		**-**	**$103.5**
Bioenergy Optimization Program	62.1	133.9	-	$38.7
Customer Sited Load Displacement	75.4	593.2	-	$99.5
Load Displacement & Alternative Energy	**137.5**	**727.1**	**-**	**$138.3**
Conservation Rates - Residential	19.6	161.6	-	$13.4
Conservation Rates - Commercial	29.5	243.6	-	$17.6
Conservation Rates	**49.1**	**405.2**	**-**	**$30.9**
Fuel Choice	145.6	291.3	-27.7	$54.6
Fuel Choice	**145.6**	**291.3**	**-27.7**	**$54.6**
Residential Air Source Heat Pumps Program	-	6.3	-	$2.2
Residential Future Opportunities	17.3	83.3	-	$45.9
Residential Solar Photovoltaics Program (PV)	7.2	79.3	-	$59.8
Residential Solar Thermal Program - Water Heating	0.3	3.0	-	$1.5
Residential Solar Thermal Program - Pool Heating	-	2.2	1.4	$1.1
Commercial Future Opportunities	17.3	83.3	-	$49.6
Commercial Solar Photovoltaics Program (PV)	12.1	114.0	-	$71.9
Commercial Variable Speed and Frequency Drives	0.1	6.6	-	$3.4
Industrial Future Opportunities	17.3	83.3	-	$54.4
Other Emerging Technologies	**71.6**	**461.4**	**1.4**	**$289.8**
Impacts	**970.0**	**3,432.3**	**49.5**	**$1,304.4**
Codes, Standards & Regulations	317.7	1,187.1	77.7	-
Interactive Effects	-	-	-9.1	-
Program Support	-	-	-	$89.3
Power Smart Plan - 2015/16 - 2029/30	**1,288**	**4,619**	**118**	**$1,394**

1.2 DSM Market Transformation Strategy

Manitoba Hydro's DSM strategy is to aggressively pursue all cost effective energy efficiency opportunities and continually monitor the market to identify emerging trends and opportunities which may become viable and cost effective DSM initiatives within the planning horizon with the end goal of creating a sustainable market change where the energy efficient technology or practice ("EE measure") becomes the market standard.

To accomplish this in a manner that ensures permanent market transformation to the EE measure is achieved, a long term and comprehensive approach is used that involves different market intervention strategies at the various stages of the EE measure's adoption into the market. These strategies are researched and designed using a collaborative approach considering the input and expertise of the entire delivery channel for the EE measure including designers, suppliers, retailers and target customers.



Infancy

When an EE measure is first introduced to the market, it is typically received with skepticism on the part of installers, facility owners and consumers. The market is also often characterized by limited availability of the product, higher costs and, in many cases, unverified or untested energy performance claims. These conditions make it difficult to develop and increase market acceptance for the product. Lack of informed suppliers or experienced installers is also an issue with some EE measures, as many industry participants prefer to retain their own "tried and true" supply chain and installation methods.

It is of utmost importance in this phase that these barriers are addressed otherwise the EE measure will face difficulty with achieving market penetration and may fail to enter the growth stage.

Market Intervention Strategies:

Research and Development including possible demonstrations project showcasing the EE technology are important to demonstrate the performance claims for the measure and possibly to even highlight areas where the EE measure can be improved. For technologies related to space and water heating in particular, local field demonstration experience can be critical to increasing acceptance, due to Manitoba's climate differences from typical laboratory or field testing. Demonstrations also have additional benefits through the ability to become showcases for the purpose of education and a future basis for communications that incorporate "real world" experiences that installers and customers can identify with operational performance.

If the energy performance of the EE technology is already known or has been verified through research and demonstration, communication strategies focusing on education to the market are critical to building awareness of the EE measure and its benefits.

Policy relating to energy efficiency is a very powerful strategy for EE measures in the infancy stages as it encourages government stakeholders to be to become leaders with energy efficiency and be the early adopters of the new technology. Early adopters are critical to the successful launch of new EE measures as they help to build the base industry infrastructure by creating initial demand.

Growth

Once the barriers of the Infancy stage have been identified and a strategy to address the barriers has been successfully implemented for the EE measure, market penetration begins to rise, whether voluntarily or through a policy strategy. In the early stages of growth, there needs to be a balanced approach to creating demand for the measure while ensuring that the market has developed qualified and knowledgeable providers in order to meet the emerging demand. EE measures in early growth can face irreparable damage if the early majority adopters lose confidence in the measure due to performance that does not meet expectations.

At this stage, the product efficiency performance is established with energy benefits to the customer quantified and the non-energy benefits have been identified. However, there will still be a lack of knowledge in the market as to the optimum methods of realizing these benefits.

During later periods of the growth stage, installers and suppliers become more plentiful, there may be customers with years of successfully implementing the EE measure, and there is increased awareness of the existence of the product.

Through the majority of the growth phase, a first cost premium typically remains associated with the EE measure.

Power Smart can have a significant impact on the rate at which a product is adopted in the market regardless of the form of the program or support offered due to the immense trust that industry and consumers have in Manitoba Hydro's expertise in matters pertaining to energy efficiency.

Market Intervention Strategies:

The strategies that are employed during this phase are dependent upon the characteristics of the market the technology is directed toward, the magnitude and significance of the additional cost to the market, and the breadth of accommodation that must be made in order to effectively utilize the technology. Strategies can vary drastically not only by market segment but also by specific technology. A thorough understanding of the market, both overall characteristics and drivers and detractors to the EE measure, is essential to ensure that the program design is addressing the proper target market and contains the tools and strategies that will address the barriers present.

Marketing and communication strategies focus on comprehensive messaging that includes both the efficiency benefits and the non-energy benefits that have been attributed to the measure, and that have a perceived value to the intended target market, in order to maximize the market adoption.

With first cost still a barrier, many programs will utilize financial tools such as incentives and/or financing to encourage customer adoption of the measure. The specific tool used or the extent to which the program covers the incremental cost of the measure will vary by technology and by target market and, once again, involves consultation with the channel participants to determine the optimal contribution by Power Smart.

Equally as important to the more visible customer directed strategies are capacity building initiatives. These strategies can be especially important for those EE measures that rely on professional consultants or installers for implementation and include training, education, and certification of groups such as homebuilders, equipment installers, engineers, architects, retailers, and distributors.

In assessing options for pursing a Power Smart program to support an EE measure, Manitoba Hydro uses a number of metrics as guidelines to assess the opportunities. These metrics assist in determining whether to pursue an opportunity, how aggressive an opportunity will be pursued, the effectiveness of program design options and the relative investment sharing between ratepayers and participating customers.

Maturity

At the maturity phase of the EE measure's life cycle, the measure's use has become the preferred installation for the majority of the installers and customers in the market. At this stage, volumes have increased to the point that prices are reduced to the same level as the technology that is being replaced, or the price of the technology is in alignment with the value perceived by the customer. With these conditions, program participants often are qualified as "free riders"; in other words, they would have adopted the measure even in the absence of a program so the incentive they received was not responsible for achieving their energy savings.

Market Intervention Strategies:

During this phase, Manitoba Hydro's strategy involves pursuing the remaining opportunities through the adoption of codes and regulations. A code or a regulation ensures permanent market transformation for the specific energy efficiency opportunity since a potential always exists that the market could revert back to the non-efficient option once Power Smart has reduced or eliminated its program support.

Manitoba Hydro is heavily engaged in both Federal level and Provincial level committees that work to establish ongoing updates to minimum energy performance standards for technologies and to determine the appropriateness of their adoption into a code or a regulation. The assessment of the most appropriate exit strategy for a technology is strategized as early as at the infancy phase of the adoption life cycle of the EE measure where possible.

1.3 Power Smart Programs

The following table provides program durations and cumulative participation for incentive based and financial loan programs over the 15 year planning horizon. For program descriptions, please refer to the current approved DSM plan (2015/16 Power Smart Plan). For programs not approved but where placeholders are used, detail program descriptions are not available at this time.

Program Duration and Cumulative Participation
2015/16 - 2029/30

Programs	Program Category	Electric	Natural Gas	Program Launch Date	Participation Definition	Cumulative Participation by 2029/30
Residential						
New Home Program	Incentive Based	√	√	Apr-2017	No. of houses	1,381
Home Insulation Program	Incentive Based	√	√	May-2004	No. of houses	58,505
Water and Energy Saver Program	Incentive Based	√	√	Sep-2010	No. of houses	201,247
Affordable Energy Program	Incentive Based	√	√	Dec-2007	No. of retrofits	45,843
Refrigerator Retirement Program	Incentive Based	√		Jun-2011	No. of appliances	55,017
Drain Water Heat Recovery Initiative	Incentive Based	√		Apr-2015	No. of houses	1,856
Residential LED Lighting Program	Incentive Based	√		Apr-2014	No. of bulbs	1,089,561
Community Geothermal Program	Incentive Based	√		Apr-2013	No. of geothermal systems	3,972
Power Smart Residential Loan	Financial Loan	√	√	Feb-2001	No. of loans	161,059
Power Smart PAYS Financing	Financial Loan	√	√	Nov-2012	No. of loans	7,252
Residential Earth Power Loan	Financial Loan	√	√	Apr-2002	No. of loans	3,885
Commercial						
Commercial Lighting Program	Incentive Based	√		Apr-1992	No. of projects	20,463
LED Roadway Lighting Conversion Program	Incentive Based	√		Apr-2014	No. of conversions	155,133
Commercial Building Envelope - Windows Program	Incentive Based	√	√	Dec-1995	No. of projects	5,124
Commercial Building Envelope - Insulation Program	Incentive Based	√	√	Dec-1995	No. of projects	5,170
Commercial Geothermal Program	Incentive Based	√		Dec-1995	No. of buildings	1,066
Commercial HVAC Program - Boilers	Incentive Based		√	Sep-2003	No. of boilers	2,728
Commercial HVAC Program - Chillers	Incentive Based	√		Sep-2003	No. of chillers	184
Commercial HVAC Program - CO2 Sensors	Incentive Based	√	√	Apr-2009	No. of sensors	2,128
Commercial HVAC Program - HRVs	Incentive Based	√	√	Apr-2016	No. of units	276
Commercial HVAC Program - Air Cooled Chillers	Incentive Based	√		Apr-2017	No. of chillers	338
Commercial HVAC Program - Water Heaters	Incentive Based		√	Apr-2015	No. of water heaters	1,018
Commercial Custom Measures Program	Incentive Based	√	√	Dec-1995	No. of projects	384
Commercial Building Optimization Program	Incentive Based	√	√	Apr-2006	No. of buildings	164
New Buildings Program	Incentive Based	√	√	Apr-2009	No. of buildings	246
Commercial Refrigeration Program	Incentive Based	√		Apr-2006	No. of locations	3,673
Commercial Kitchen Appliance Program	Incentive Based	√	√	Jan-2008	No. of appliances	2,681
Network Energy Management Program	Incentive Based	√		May-2008	No. of licenses	30,036
Internal Retrofit Program	Incentive Based	√	√	Jul-1995	No. of projects	1,499
Power Smart Shops	Incentive Based	√	√	Feb-2009	No. of projects	5,708
Power Smart Energy Manager	Incentive Based	√	√	Apr-2015	No. of managers	3
Power Smart for Business PAYS Financing	Financial Loan	√	√	Sep-2013	No. of loans	418
Industrial						
Performance Optimization Program	Incentive Based	√		Jun-1993	No. of projects	3,018
Natural Gas Optimization Program	Incentive Based		√	Sep-2006	No. of projects	221
Load Management						
Curtailable Rate Program	Incentive Based	√		Nov-1993	No. of customers	97 *
Load Displacement & Alternative Energy						
Bioenergy Optimization Program	Incentive Based	√	√	Mar-2006	No. of projects	231
Customer Sited Load Displacement	Incentive Based	√		Apr-2014	No. of customers	28
Conservation Rates	Rate Based	√		2018/19	Rate Based	-
Fuel Choice	Incentive Based	√		2017/18	No. of installations	15,720
Other Emerging Technologies						
Residential Air Source Heat Pumps Program	Incentive Based	√		2021/22	No. of projects	1,035
Residential Future Opportunities	Incentive Based	√		2020/21	Various	Various
Residential Solar Photovoltaics Program (PV)	Incentive Based	√		2020/21	No. of systems	26,402
Residential Solar Thermal Program - Water Heating	Incentive Based	√		2017/18	No. of systems	1,199
Residential Solar Thermal Program - Pool Heating	Incentive Based	√	√	2017/18	No. of systems	1,116
Commercial Future Opportunities	Incentive Based	√		2020/21	Various	Various
Commercial Solar Photovoltaics Program (PV)	Incentive Based	√		2020/21	No. of systems	1,519
Commercial Variable Speed and Frequency Drives	Incentive Based	√		2017/18	No. of drives	569
Industrial Future Opportunities	Incentive Based	√		2020/21	Various	Various

**Participation recurs annually*

1.4 Risk Analysis

Demand Side Management (DSM) involves risk in both deliverability and cost. Deliverability risk is the risk that the DSM plan does not deliver the projected electric capacity and energy savings within the specified time frame. Cost risk is related to DSM program costs, including incentives and administration, and the associated risk of revenue loss or cost recovery due to reduced levels of energy consumption.

The cost risk of DSM to the utility customer is an important consideration in understanding the risk of both deliverability and cost for Manitoba Hydro. Most DSM measures require a significant investment by the customer (generally greater than 50 percent of total costs) with the customer's willingness and capability to invest their portion of the capital and operating expense being heavily dependent on alternative uses of capital, the reliability of energy savings and the added value of non-energy benefits related to comfort, convenience, safety, productivity and other non-energy benefit streams. As such, these risks to the customer are an important aspect of assessing the risk to Manitoba Hydro.

This section summarizes these risks, outlines Manitoba Hydro's past performance in achieving DSM targets, assesses the appropriate level of risk and describes how these risks will be managed.

1.4.1 DSM Risks

Power Smart Programs

Participation rate - DSM programs rely on customers to participate, with the level of participation impacting the electricity and natural gas savings achieved. The timing and degree of participation by customers (residential, commercial and industrial) can be greatly influenced by a number of factors including their knowledge and understanding of the measure's relevance to their needs and energy consumption, product maturity, market support, alternative uses of capital, available non-energy benefits, and external factors such as the economy and spending priorities. Capital prioritization among customers is heavily influenced by the relevance of the measure to their business priorities. In addition, periods of economic decline may reduce customer participation rates, even in instances when energy efficiency projects have high returns, due to capital rationing, balance sheet status, funding priorities and other considerations.

Energy savings per participant – Energy savings per participant could be higher or lower than forecast. While variations in energy savings among customers for a particular measure is always anticipated, it is reasonable to expect that the range of variations for a particular measure can be accounted with reasonable precision if adequate technical and market information is available.

Program cost - Non-incentive and incentive costs could be higher or lower than forecast. Measure costs and related incentive costs for Manitoba Hydro may vary over the life of a program to account for increasing measure maturity and growing market acceptance. It is generally accepted that initial entry into the market requires greater levels of engagement by the utility, including higher incentive costs, to overcome barriers associated with market knowledge and understanding, hesitance to accept new technologies and higher initial costs. A lower level of initial measure maturity results in higher upfront costs to the utility, which generally decline as the measure matures and market acceptance improves. Market maturity is influenced by materials development, product refinement,

manufacturing growth, and growth within the sales and distribution network that provides for availability and after-sales support demanded by customers. Forecasting the pace of market maturity can be challenging, influencing program costs over the life of a program, but Manitoba Hydro works closely with industry to advance market maturity and to remain aware of potential changes in the market.

While costs incurred by utilities for DSM are generally recovered through rates and avoided costs for the deferral of more costly generation, transmission and distribution assets, revenue loss from widespread market acceptance of DSM measures such as distributed generation are also accompanied by the additional costs of integrating renewable resources with highly variable outputs. Recovery of these costs is currently an active topic among utilities in California where distributed generation is approaching 5 percent of total generation resources. This is not a near-term risk for Manitoba Hydro due to its low rates and it is anticipated that regulators will have developed methodologies for addressing these costs by the time they become an issue for Manitoba.

Regulatory approval- Programs relying upon specific price signals through rate design such as Conservation Rates will be subject to approval by the Manitoba Public Utilities Board. The timing and level of energy reductions to be achieved under these initiatives may be impacted by the rulings of this Board, which may be influenced by priorities such as rate impacts to low income customers.

Codes and Standards

Government approval- Changes to codes and standards are implemented by government and subject to government approval. At present, government support for energy efficiency codes and standards is strong, with considerable interest and support from all levels of government. Harmonization across North America between Canada and the US is progressing well, creating a more uniform and persuasive market impact through common energy efficiency regulations that directly influence manufacturers. As such, it is anticipated that the influence of codes and standards will remain consistent and supportive to DSM measures over the coming decades. Growing calls for strengthened greenhouse gas emission targets and carbon economy regulation are likely to advance the push for greater use of DSM measures across Canada and the US.

Coverage - Codes and standards can apply to all or a subset of equipment and buildings, which will impact the resulting electric and natural gas savings. Energy codes present a significant opportunity for future DSM savings. Federal efforts directed towards future editions of building energy codes are well advanced, so it is anticipated that adoption of future energy codes will continue to be supportive of both electric and natural gas savings as improved methods of modeling energy performance are adopted into the marketplace. These improved and easily accessible modeling tools will highlight potential opportunities for energy savings within buildings, supporting the development of more energy efficient materials and construction practices within the construction industry.

Efficiency level- The minimum efficiency level prescribed in codes and standards can vary and this will also impact the resulting electricity and natural gas savings.

Compliance - Once a code or standard is in place, electric and natural gas savings will depend on the degree to which consumers, builders and other market players comply with the requirements and the ability of the governing bodies to monitor and enforce compliance. Compliance is a key concern for utilities as it largely rests with local municipal enforcement agencies that are often under-resourced. To support compliance, Manitoba Hydro often establishes existing codes and standards as base criteria for involvement in DSM programming, driving the market to become minimally compliant with codes and regulations related to energy performance.

1.4.2 Past DSM Performance

To gain a perspective on the risk of achieving DSM targets, it is useful to view past performance in achieving the forecast DSM targets. This section outlines Manitoba Hydro's achievements of its long term, mid-term and short term DSM targets.

Long Term Analysis (10 yr)

The 10 year electric DSM targets were compared to energy savings achieved from all past Power Smart Plans where the tenth year has concluded. Achieved electric savings surpassed planned savings for all three plans by a significant margin. This margin is reasonable and expected as these early plans were conservative in nature and additional opportunities were persued subsequent to the plan being developed. Ultimately, this assessment demonstrates that historically Manitoba Hydro has achieved its long term electric DSM forecasts.

	10 yr Actual (GW.h)	10 yr Target (GW.h)	Difference	% Above / (Below) Target	
2000 PS Plan	842	452	390	86%	*
2001 PS Plan	963	511	452	88%	*
2005 PS Plan	1,711	1,312	399	30%	
Average	**1,172**	**758**	**414**	**55%**	

** Actual savings exclude savings due to standards*

Mid Term Analysis (5 yr)

To assess mid-term DSM achievability, the 5 year electric and natural gas DSM targets were compared to achieved savings. Overall, for both electricity and natural gas, achieved savings met or exceeded the targeted savings. This assessment indicates that in the mid-term, Manitoba Hydro has achieved its planned electric and natural gas forecasts. It also indicates that the variability from forecasted savings decreases as the forecast time spans are reduced.

It should be noted that the natural gas targets in the 2005 Power Smart Plan were dramatically surpassed by the savings achieved. As this was the first Power Smart Plan to include natural gas savings, the targets were conservative and were subsequently exceeded by more aggressive DSM activities.

	5 yr Actual (GW.h)	5 yr Target (GW.h)	Difference	% Above / (Below) Target	
2000 PS Plan	224	250	-26	-11%	*
2001 PS Plan	321	288	33	11%	*
2005 PS Plan	708	634	74	12%	
2006 PS Plan	826	799	27	3%	
2008 PS Plan	928	834	94	11%	
2009 PS Plan	1,106	1,120	-14	-1%	
2010 PS Plan	1,154	1,131	23	2%	
Average	**752**	**722**	**30**	**4%**	

** Actual savings exclude savings due to standards*

	5 yr Actual (million m^3)	5 yr Target (million m^3)	Difference	% Above / (Below) Target	
2000 PS Plan	n/a	n/a	n/a	n/a	
2001 PS Plan	n/a	n/a	n/a	n/a	
2005 PS Plan	36.9	15.5	21.4	138%	*
2006 PS Plan	42.3	38.9	3.4	9%	*
2008 PS Plan	53.9	53.5	0.4	1%	
2009 PS Plan	53.3	41.6	11.7	28%	
2010 PS Plan	53.5	44.0	9.5	22%	
Average	**48.0**	**38.7**	**9.3**	**24%**	

** Actual savings exclude savings due to standards*

Short Term Analysis (1 yr)

To assess short term DSM achievability, the annual electric and natural gas DSM targets were compared to achieved savings. Overall, achieved electric and natural gas energy savings surpassed the planned DSM savings. This analysis demonstrates that in the short term Manitoba Hydro has generally achieved its forecasted electric and natural gas forecasts.

It should be noted that the shortfall for electric savings in 2014/15 was mainly due to unanticipated delays in the Load Displacement Program. This initiative was a new addition to the plan and the forecasted savings did not account for the difficulty in implementing such large scale projects. This demonstrates that the timelines may vary for the implementation of some DSM projects, however this is just a year-over-year variability and not a risk to the overall achievement of DSM targets over a longer period of time.

	1 yr Actual (GW.h)	1 yr Target (GW.h)	Difference	% Above / (Below) Target	
2009-2010	263	311	-48	-15%	
2010-2011	268	258	10	4%	
2011-2012	260	240	20	8%	
2012-2013	332	173	159	92%	
2013-2014	260	177	83	47%	
2014-2015	281	363	-81	-22%	*
Average	**277**	**254**	**24**	**9%**	

** Actual savings reflect unaudited estimate*

	1 yr Actual (million m^3)	1 yr Target (million m^3)	Difference	% Above / (Below) Target	
2009-2010	7.3	7.9	-0.6	-8%	
2010-2011	11.2	6.7	4.5	67%	
2011-2012	14.4	10	4.4	44%	
2012-2013	14.6	10	4.6	46%	
2013-2014	9.0	10.3	-1.3	-13%	
2014-2015	12.6	10.2	2.4	24%	*
Average	**11.5**	**9.2**	**2.3**	**26%**	

** Actual savings reflect unaudited estimate*

1.4.3 Risk Management

As Manitoba Hydro's DSM plan involves a diverse offering of many programs and initiatives, the risk associated with achieving the targeted energy savings is inherently minimized through diversification. In addition, the overall risk is further reduced by undertaking ongoing and regular reviews of individual program performance and making regular adjustments to the Corporation's overall DSM plan on an annual basis.

Energy Efficiency Programs – Risk Level: Low

Energy Efficiency programs present a relatively low level of risk to the Corporation. Energy efficiency program participation and resulting savings build gradually over time which allows for adjustment to the program designs, ensuring alignment with long term targets. Program participation and resulting energy and capacity savings achieved are tracked quarterly for each initiative to provide timely feedback and opportunity for design changes. Similarly, program costs are managed by comparing expenditures to the program budget on a monthly basis to identify variances from planned expenditures. Free ridership rates and other factors that impact program energy and capacity savings are also measured on an annual basis through the impact evaluation process which also provide timely feedback. Although Manitoba Hydro's overall plan is formally adjusted on an annual basis, adjustments are made to specific programs throughout the year and implemented when deemed appropriate.

Load Displacement and Alternative Energy Programs – Risk Level: High

The risk associated with achieving the energy savings with the Load Displacement and Alternative Energy programs present a relatively high level of risk to the Corporation. This risk is generally related more towards the timing of the achievement of the energy savings. These initiatives involve a much smaller number of customers, large capital investment required by customers, complex installations and the need to integrate the projects into production processes while minimizing downtime. Since each of the smaller number of participants have large potential energy and capacity savings, there is less diversification in the load displacement portfolio, meaning variances in the timing of these projects will have a dramatic impact on annual targets for both program expenditures and energy and capacity savings. The risks will be managed by working closely with customers and by assisting them with assessing their respective business cases supporting each opportunity. Although there is a short-term timing risk related to the implementation of the projects, the long-term impact to Manitoba Hydro is relatively insignificant provided the projects are undertaken within a reasonable period of time and prior to decisions involving adding new generation supply in Manitoba. There is a reasonable probability that the majority of the identified projects will be implemented within the time frame of this plan.

Conservation Rates Initiative – Risk Level: Medium

The Conservation Rate initiatives (i.e. residential and commercial) involve a medium level of risk to the Corporation. Manitoba Hydro intends to manage this risk by using a third-party consultant to assist with the estimation of energy savings and by working closely with key stakeholders to address their specific concerns. A similar initiative has already been implemented by B.C. Hydro and Manitoba Hydro will take the opportunity to learn from their experiences.

Fuel Choice Initiative – Risk Level: Medium to High

Achieving the energy savings associated with the Fuel Choice initiative presents a medium to high level of risk to the Corporation. This initiative involves encouraging customers to switch from using electricity to natural gas for space heating purposes where natural gas is available. This initiative would result in participating customers having lower heating bills however it would result in higher regional emissions and lower global emissions. Given the dynamics associated with this initiative, Manitoba Hydro has mixed support for pursuing this initiative by its various stakeholders. For example, the provincial government is not supportive of Manitoba Hydro pursuing this opportunity while some interveners are strong advocates of Manitoba Hydro aggressively pursuing the opportunity. Manitoba Hydro is managing this risk by continuing to have discussions with its key stakeholders to assess whether the opportunity will or should be pursed.

Other Emerging Technologies – Risk Level: Medium to High

The Other Emerging Technologies category presents a medium to high level of risk to the Corporation. As these are emerging technologies, there are risks related to the pace of product development, the cost of products and market acceptance. Manitoba Hydro will manage this risk by continuing to monitor progress in technology and/or product development and by making adjustments to its DSM plan on an ongoing basis.

Codes and Standards – Risk Level: Low

The Codes and Standards category presents a low level of risk to the Corporation. Once codes are adopted in Manitoba there is still a requirement for enforcement, which is the responsibility of the Office of the Fire Commissioner and the City of Winnipeg and other larger municipal entities. Given that energy efficiency in the building code is relatively new, mechanisms for enforcement and training of code authorities will need to be formalized. Manitoba Hydro will help manage this risk by assisting code authorities and industry stakeholders with the identification of key aspects of building energy code, supporting the industry in areas of difficulty and provide training for both industry and code officials. Manitoba Hydro's longer term strategy of developing programs that are aligned with future code requirements will also assist in mitigating the risk by educating the industry on energy efficient technologies and design practices that will eventually be introduced and enforced within energy codes.

Energy savings achieved through the implementation of energy performance standards for equipment and systems are often referenced in Power Smart programs and Energy Efficiency Regulations. Energy savings achieved through federal regulations applying to goods imported into Canada are relatively secure and risk-free. Energy savings achieved through provincial regulations with lower levels of compliance enforcement are generally less secure and therefore contain greater risk in achievement. Manitoba Hydro will help manage the risks by continuing to make energy performance standards a core component of eligibility for Power Smart program incentives. In this manner, customers and vendors become accustomed to compliance with the standards, easing compliance with regulations that generally arrive once market acceptance of new energy efficient technologies has been achieved through the influence of utility programs.

1.5 Economic Assumptions

Marginal Costs

The 2015 Power Smart Plan incorporated the following forecasts to estimate the marginal benefits for energy savings resulting from the revenue realized from conserved electricity being sold in the export market, the avoided costs of new transmission and the supply of natural gas:

- Electric – The electric marginal cost forecast was prepared and compiled by the Resource Planning and Market Analysis Department. Marginal values were provided for savings at the distribution level, transmission level, generation level and for the value of curtailable load. For the 2015 Power Smart Plan, the following assumptions were applied:

    - Marginal costs were based on a uniform supply with a 100% capacity factor
    - Distribution Level Programs used a loss factor of 14% to translate back to generation
    - General Service Large Programs used a loss factor of 10% to translate back to generation
    - Generation Level Programs used a loss factor of 14% to translate to distribution level
    - US/Cdn Exchange Rates and Escalation Factors were derived from the Corporation's G911 corporate policy document issued October 9th, 2014
    - Transmission & distribution marginal costs were updated using SPD 2010/02

- Natural Gas – The alternative cost forecast for natural gas was prepared based on the natural gas price forecast which was provided by the Economic Analysis Department. Unlike the price forecast, it does not include distribution costs. The benefits of avoided greenhouse gas emissions were included in the natural gas marginal benefits used to calculate the Societal Cost (SC) and Total Resource Cost (TRC) metric. A greenhouse gas cost forecast was provided by the Energy Policy & Analysis Department.

- In addition, water benefits were calculated based on 2015 City of Winnipeg Water and Sewer rates effective January 1st, 2015.

Customer Rates

The following forecasts were used to determine the impact of customer bill reductions resulting from their Power Smart energy savings:

- Electric – The Electric Rates & Regulatory Department provided the rate forecast for electricity. Commercial and industrial program rates were determined by a weighted average based on the forecast participation by each of the Corporations' billing classes. Residential rates were consistent for all residential programs. For the 2015 Power Smart Plan, the weighted rates were based on the approved May 1st, 2014 rate forecast which assumed the 2014/15 real rates would increase by 2.0% and thereafter by 2.0% per year. This was based on the projected rate increase of 3.95% for 2015/16 and the long term rate increase of 3.95% per year (as per IFF-13) less the 2015/16 escalation rate of 2.0 % and the long term escalation rate of 2% (2013 Economic Outlook), (represented in 2015 $).

- Natural Gas – The natural gas price forecast was prepared by the Economic Analysis Department with input from the Energy Price Outlook. For the 2015 Power Smart Plan, the following assumptions were applied:
    - Forecast starting point was the February 1st, 2014 rate
    - Commodity price changes into the future were based on the forecast of natural gas prices contained in the Energy Price Outlook which represented a consensus view of futures markets and a suite of five independent forecasting organizations
    - Non-commodity (monthly charge, transportation, distribution) price changes were based on IFF-13 assumptions on general rate increases and the Economic Outlook assumptions on Manitoba inflation. Non-commodity price changes in the post-IFF period were based on historical trends

Economic Variables

For the 2015 Power Smart Plan, the Projected Escalation, Interest, & Exchange Rates – G911 corporate policy document issued October 9th, 2014 was used to discount all forward-looking savings and costs. The real weighted average cost of capital of 4.75% was used to discount real dollar cash flows and energy savings. Rates for all historical benefits, costs, and energy savings used actual economic results for each year.

1.6 Comparison to 2014 DSM Forecast

Electric DSM Targets Comparison

The planned electric energy savings in this plan are approximately 641 GW.h higher than previously forecast in the 2014-2017 Power Smart Plan, resulting in a 16% increase. The following section highlights programs with notable changes.

New Home Program (-)

- Decrease due to revisions in future building code savings based on updated market information.

Affordable Energy Program (+)

- Reflects increase in participation levels and extension of program to Multi-unit residential buildings

Refrigerator Retirement Program (+)

- Program extended an additional 6 years.

Commercial Lighting (+)

- Increase due to greater uptake of LED technology.

LED Roadway Lighting Conversion Program (+)

- Increase due to additional replacements.

Commercial Geothermal Program (-)

- Decrease due to reductions in market penetration levels based on updated market information.

New Buildings Program (+)

- Increase due to additional savings from future building code.

Performance Optimization (-)

- Decrease due to revisions to program participation based on updated market information.

Load Displacement & Alternative Energy (+)

- Increase due to the inclusion of additional biomass opportunities.

Other Emerging Technologies (+)

- Increase due to exploration of future technologies.

Codes and Standards (-)

- Decrease reflects updated market information.

	2015 DSM Forecast (GW.h)	2014 DSM Forecast (GW.h)	Change	% Contribution to overall change
New Home Program	19.2	45.5	-26.3	-4%
Home Insulation Program	32.1	35.6	-3.5	-1%
Water and Energy Saver Program	16.5	14.0	2.5	0%
Affordable Energy Program	44.3	35.5	8.8	1%
Refrigerator Retirement Program	16.6	1.7	14.9	2%
Drain Water Heat Recovery Initiative	1.9	0.0	1.9	0%
Residential LED Lighting Program	11.0	6.8	4.3	1%
Community Geothermal Program	64.3	68.1	-3.8	-1%
Power Smart Residential Loan	7.3	8.5	-1.3	0%
Power Smart PAYS Financing	3.5	6.0	-2.5	0%
Residential Earth Power Loan	18.2	20.6	-2.4	0%
Residential Programs	**234.9**	**242.2**	**-7.3**	**-1%**
Commercial Lighting Program	436.1	289.9	146.1	23%
LED Roadway Lighting Conversion Program	59.3	40.3	19.0	3%
Commercial Building Envelope - Windows Program	29.7	36.3	-6.6	-1%
Commercial Building Envelope - Insulation Program	32.3	34.3	-1.9	0%
Commercial Geothermal Program	87.1	115.8	-28.8	-4%
Commercial HVAC Program - Boilers	-	-	-	-
Commercial HVAC Program - Chillers	9.9	9.6	0.2	0%
Commercial HVAC Program - CO2 Sensors	3.2	2.0	1.2	0%
Commercial HVAC Program - HRVs	11.6	0.0	11.6	2%
Commercial HVAC Program - Air Cooled Chillers	15.6	0.0	15.6	2%
Commercial HVAC Program - Water Heaters	-	-	-	-
Commercial Custom Measures Program	29.5	24.6	5.0	1%
Commercial Building Optimization Program	21.8	16.4	5.4	1%
New Buildings Program	149.9	55.9	94.0	15%
Commercial Refrigeration Program	66.0	70.8	-4.8	-1%
Commercial Kitchen Appliance Program	2.0	2.5	-0.5	0%
Network Energy Management Program	3.8	5.4	-1.6	0%
Internal Retrofit Program	7.7	3.1	4.6	1%
Power Smart Energy Manager	4.6	0.0	4.6	1%
Power Smart Shops	3.9	4.5	-0.6	0%
Power Smart for Business PAYS Financing	0.0	2.6	-2.6	0%
Commercial Programs	**973.9**	**713.9**	**260.0**	**41%**
Performance Optimization Program	338.7	399.8	-61.2	-10%
Natural Gas Optimization Program	-	-	-	-
Indutrial Programs	**338.7**	**399.8**	**-61.2**	**-10%**
Energy Efficiency Subtotal	**1,547.4**	**1,356.0**	**191.5**	**30%**
Curtailable Rate Program	-	-	-	-
Load Management	**-**	**-**	**-**	**-**
Bioenergy Optimization Program	133.9	68.1	65.8	10%
Customer Sited Load Displacement	593.2	638.6	-45.5	-7%
Load Displacement & Alternative Energy	**727.1**	**706.7**	**20.4**	**3%**
Conservation Rates - Residential	161.6	159.7	1.9	0%
Conservation Rates - Commercial	243.6	230.4	13.2	2%
Conservation Rates	**405.2**	**390.0**	**15.1**	**2%**
Fuel Choice	291.3	285.8	5.4	1%
Fuel Choice	**291.3**	**285.8**	**5.4**	**1%**
Residential Air Source Heat Pumps Program	6.3	0.0	6.3	1%
Residential Future Opportunities	83.3	0.0	83.3	13%
Residential Solar Photovoltaics Program (PV)	79.3	0.0	79.3	12%
Residential Solar Thermal Program - Water Heating	3.0	0.0	3.0	0%
Residential Solar Thermal Program - Pool Heating	2.2	0.0	2.2	0%
Commercial Future Opportunities	83.3	0.0	83.3	13%
Commercial Solar Photovoltaics Program (PV)	114.0	0.0	114.0	18%
Commercial Variable Speed and Frequency Drives	6.6	0.0	6.6	1%
Industrial Future Opportunities	83.3	0.0	83.3	13%
Other Emerging Technologies	**461.4**	**0.0**	**461.4**	**72%**
Impacts	**3,432.3**	**2,738.6**	**693.8**	**108%**
Codes, Standards & Regulations	1,187.1	1,239.7	-52.5	-8%
Interactive Effects	-	-	-	-
Program Support	-	-	-	-
Power Smart Plan - 2015/16 - 2029/30	**4,619**	**3,978**	**641**	**100%**

Natural Gas DSM Targets Comparison

The natural gas savings expected to be achieved through this plan are 10 million cubic metres higher than previously forecast in the 2014-15 Power Smart Plan, resulting in a 9% increase. The following section highlights programs with notable changes.

New Home Program (-)

- Decrease due to revisions in future building code savings based on updated market information.

Home Insulation Program (-)

- Decrease due to a decline in forecasted average savings per application and anticipated participation levels.

Commercial HVAC Program – Boilers (+)

- Reflects program extended an additional 2 years and an increase in forecasted average savings per application.

Commercial HVAC Program – C02 Sensors (-)

- Decrease due to a decline in forecasted average savings per application.

Commercial HVAC Program – HRVs (+)

- Increase due to new initiative offered in 2015.

Commercial Building Optimization Program (+)

- Increase due to higher anticipated participation levels.

New Buildings Program (+)

- Increase due to additional savings from future building code.

Natural Gas Optimization Program (+)

- Increase due to extension of program offering.

Load Displacement & Alt. Energy (-)

- Decrease reflects updated market opportunities.

Fuel Choice (+)

- Increase due to revisions based on updated market information.

Other Emerging Technologies (+)

- Increase due to exploration of future technologies.

Interactive Effects (-)

- Reflects greater volume required due to additional cooling effects from energy efficient lighting.

	2015 DSM Forecast (million m^3)	2014 DSM Forecast (million m3)	Change	% Contribution to overall change
New Home Program	5.4	6.4	-1.0	-10%
Home Insulation Program	7.2	8.9	-1.7	-17%
Water and Energy Saver Program	1.6	2.5	-0.8	-8%
Affordable Energy Program	6.2	6.1	0.0	0%
Refrigerator Retirement Program	-	-	-	-
Drain Water Heat Recovery Initiative	-	-	-	-
Residential LED Lighting Program	-	-	-	-
Community Geothermal Program	-	-	-	-
Power Smart Residential Loan	3.9	4.6	-0.7	-7%
Power Smart PAYS Financing	0.0	0.1	-0.1	-1%
Residential Earth Power Loan	1.4	2.0	-0.6	-6%
Residential Programs	**25.8**	**30.7**	**-4.9**	**-49%**
Commercial Lighting Program	-	-	-	-
LED Roadway Lighting Conversion Program	-	-	-	-
Commercial Building Envelope - Windows Program	4.0	4.2	-0.2	-2%
Commercial Building Envelope - Insulation Program	13.0	13.1	-0.1	-1%
Commercial Geothermal Program	-	-	-	-
Commercial HVAC Program - Boilers	5.6	4.7	0.9	9%
Commercial HVAC Program - Chillers	-	-	-	-
Commercial HVAC Program - CO2 Sensors	1.0	2.8	-1.8	-18%
Commercial HVAC Program - HRVs	2.9	0.0	2.9	29%
Commercial HVAC Program - Air Cooled Chillers	0.0	0.0	0.0	0%
Commercial HVAC Program - Water Heaters	1.3	0.7	0.6	6%
Commercial Custom Measures Program	1.9	2.1	-0.2	-2%
Commercial Building Optimization Program	4.9	3.7	1.2	12%
New Buildings Program	4.1	1.5	2.6	26%
Commercial Refrigeration Program	0.0	0.0	0.0	0%
Commercial Kitchen Appliance Program	0.7	1.0	-0.3	-3%
Network Energy Management Program	0.0	0.0	0.0	0%
Internal Retrofit Program	0.0	0.0	0.0	0%
Power Smart Energy Manager	0.4	0.0	0.4	4%
Power Smart Shops	0.1	0.1	-0.1	-1%
Power Smart for Business PAYS Financing	0.0	0.1	-0.1	-1%
Commercial Programs	**39.8**	**34.0**	**5.8**	**59%**
Performance Optimization Program	-	-	-	-
Natural Gas Optimization Program	10.1	4.8	5.3	53%
Indutrial Programs	**10.1**	**4.8**	**5.3**	**53%**
Energy Efficiency Subtotal	**75.7**	**69.5**	**6.3**	**63%**
Curtailable Rate Program	-	-	-	-
Load Management	**-**	**-**	**-**	**-**
Bioenergy Optimization Program	0.0	1.7	-1.7	-17%
Customer Sited Load Displacement	-	-	-	-
Load Displacement & Alternative Energy	**0.0**	**1.7**	**-1.7**	**-17%**
Conservation Rates - Residential	-	-	-	-
Conservation Rates - Commercial	-	-	-	-
Conservation Rates	**-**	**-**	**-**	**-**
Fuel Choice	-27.7	-38.8	11.1	112%
Fuel Choice	**-27.7**	**-38.8**	**11.1**	**112%**
Residential Air Source Heat Pumps Program	-	-	-	-
Residential Future Opportunities	-	-	-	-
Residential Solar Photovoltaics Program (PV)	-	-	-	-
Residential Solar Thermal Program - Water Heating	-	-	-	-
Residential Solar Thermal Program - Pool Heating	1.4	0.0	1.4	14%
Commercial Future Opportunities	-	-	-	-
Commercial Solar Photovoltaics Program (PV)	-	-	-	-
Commercial Variable Speed and Frequency Drives	-	-	-	-
Industrial Future Opportunities	-	-	-	-
Other Emerging Technologies	**1.4**	**0.0**	**1.4**	**14%**
Impacts	**49.5**	**32.4**	**17.1**	**172%**
Codes, Standards & Regulations	77.7	78.0	-0.3	-3%
Interactive Effects	-9.1	-2.2	-6.8	-69%
Program Support	-	-	-	-
Power Smart Plan - 2015/16 - 2029/30	**118**	**108**	**10**	**100%**

Utility Cost Comparison

The planned utility cost forecast in this plan is approximately $291 million higher than previously forecast in the 2014-2017 Power Smart Plan, resulting in a 26% increase. The following section highlights programs with notable changes.

Affordable Energy Program (+)

- Reflects increase in participation levels and extension of program to Multi-unit residential buildings

LED Roadway Lighting Conversion Program (+)

- Increase due to additional replacements

Commercial Geothermal Program (-)

- Decrease due to reductions in market penetration levels based on updated market information.

Performance Optimization Program (-)

- Decrease due to revisions to program participation based on updated market information.

Load Displacement & Alt. Energy (+)

- Increase due to the inclusion of additional biomass opportunities.

Other Emerging Technologies (+)

- Increase due to exploration of future technologies.

Program support (-)

- Decrease resulting from revisions to support and administration costs.

	2015 DSM Utility Investment (Millions $)	2014 DSM Utility Investment (Millions $)	Change	% Contribution to overall change
New Home Program	$3.0	$2.6	$0.4	0%
Home Insulation Program	$31.5	$35.4	-$3.9	-1%
Water and Energy Saver Program	$6.5	$8.6	-$2.1	-1%
Affordable Energy Program	$98.0	$77.8	$20.2	7%
Refrigerator Retirement Program	$11.3	$6.7	$4.6	2%
Drain Water Heat Recovery Initiative	$0.6	$0.0	$0.6	0%
Residential LED Lighting Program	$4.7	$1.9	$2.7	1%
Community Geothermal Program	$27.8	$22.9	$4.8	2%
Power Smart Residential Loan	-	-	-	-
Power Smart PAYS Financing	-	-	-	-
Residential Earth Power Loan	-	-	-	-
Residential Programs	**$183.4**	**$156.0**	**$27.4**	**9%**
Commercial Lighting Program	$109.6	$104.2	$5.5	2%
LED Roadway Lighting Conversion Program	$56.2	$42.8	$13.4	5%
Commercial Building Envelope - Windows Program	$19.3	$21.2	-$1.9	-1%
Commercial Building Envelope - Insulation Program	$37.5	$38.5	-$1.0	0%
Commercial Geothermal Program	$44.3	$56.2	-$11.9	-4%
Commercial HVAC Program - Boilers	$3.5	$2.4	$1.1	0%
Commercial HVAC Program - Chillers	$1.8	$2.1	-$0.3	0%
Commercial HVAC Program - CO2 Sensors	$2.7	$2.7	$0.1	0%
Commercial HVAC Program - HRVs	$6.0	-	-	-
Commercial HVAC Program - Air Cooled Chillers	$6.9	-	-	-
Commercial HVAC Program - Water Heaters	$1.7	$1.0	$0.7	0%
Commercial Custom Measures Program	$13.7	$15.6	-$1.9	-1%
Commercial Building Optimization Program	$9.9	$10.1	-$0.1	0%
New Buildings Program	$20.3	$22.5	-$2.1	-1%
Commercial Refrigeration Program	$9.7	$9.8	-$0.1	0%
Commercial Kitchen Appliance Program	$0.7	$0.7	-$0.1	0%
Network Energy Management Program	$0.5	$0.8	-$0.3	0%
Internal Retrofit Program	$6.4	$2.6	$3.8	1%
Power Smart Energy Manager	$0.6	-	-	-
Power Smart Shops	$2.1	$1.9	$0.2	0%
Power Smart for Business PAYS Financing	-	$0.0	-	-
Commercial Programs	**$353.4**	**$334.9**	**$18.6**	**6%**
Performance Optimization Program	$144.4	$166.9	-$22.6	-8%
Natural Gas Optimization Program	$6.0	$2.4	$3.6	1%
Indutrial Programs	**$150.4**	**$169.3**	**-$18.9**	**-6%**
Energy Efficiency Subtotal	**$687.2**	**$660.2**	**$27.0**	**9%**
Curtailable Rate Program	$103.5	$102.9	$0.6	0%
Load Management	**$103.5**	**$102.9**	**$0.6**	**0%**
Bioenergy Optimization Program	$38.7	$11.5	$27.2	9%
Customer Sited Load Displacement	$99.5	$91.1	$8.4	3%
Load Displacement & Alternative Energy	**$138.3**	**$102.6**	**$35.6**	**12%**
Conservation Rates - Residential	$13.4	$18.0	-$4.6	-2%
Conservation Rates - Commercial	$17.6	$21.5	-$4.0	-1%
Conservation Rates	**$30.9**	**$39.5**	**-$8.6**	**-3%**
Fuel Choice	$54.6	$54.6	$0.1	0%
Fuel Choice	**$54.6**	**$54.6**	**$0.1**	**0%**
Residential Air Source Heat Pumps Program	$2.2	-	-	-
Residential Future Opportunities	$45.9	-	-	-
Residential Solar Photovoltaics Program (PV)	$59.8	-	-	-
Residential Solar Thermal Program - Water Heating	$1.5	-	-	-
Residential Solar Thermal Program - Pool Heating	$1.1	-	-	-
Commercial Future Opportunities	$49.6	-	-	-
Commercial Solar Photovoltaics Program (PV)	$71.9	-	-	-
Commercial Variable Speed and Frequency Drives	$3.4	-	-	-
Industrial Future Opportunities	$54.4	-	-	-
Other Emerging Technologies	**$289.8**	**$0.0**	**$289.8**	**100%**
Impacts	**$1,304.4**	**$959.8**	**$344.6**	**118%**
Codes, Standards & Regulations	-	$0.0	-	-
Interactive Effects	-	$0.0	-	-
Program Support	$89.3	$142.8	-$53.5	-18%
Power Smart Plan - 2015/16 - 2029/30	**$1,393.7**	**$1,102.6**	**$291.1**	**100%**

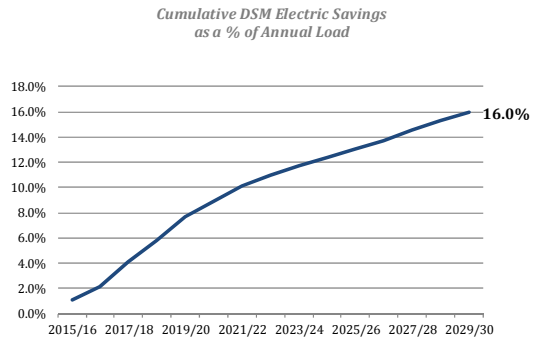
2 DEMAND SIDE MANAGEMENT

2.1 DSM Targets

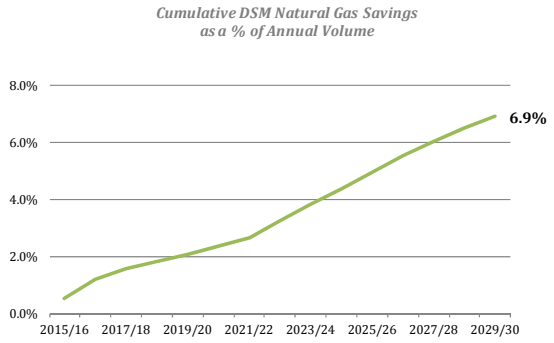
2.1.1 Electric and Natural Gas DSM Savings

In summary, the plan sets out to realize electricity savings of 1,288 MW and 4,619 GW.h, natural gas savings of 118 million cubic metres and combined global greenhouse gas emission reductions of 3.3 million tonnes by 2029/30.

This demand side management plan represents 16.0% of the estimated electric load forecast offsetting 60% of projected load growth during this period and 6.9% of the estimated natural gas volume forecast by 2029/30, further reducing natural gas consumption in Manitoba.



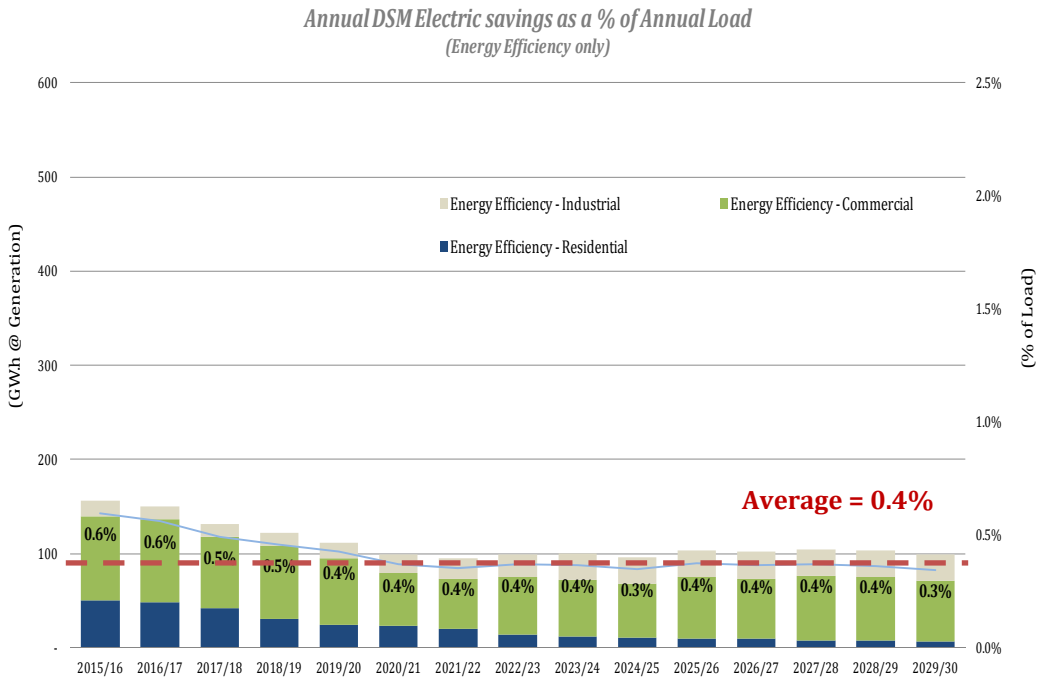
Note: Total DSM Electric savings per the above graph includes forecast savings from program impacts and savings from Codes, Standards and Regulations.
Source of Load Forecast: 2015 Electric Load Forecast

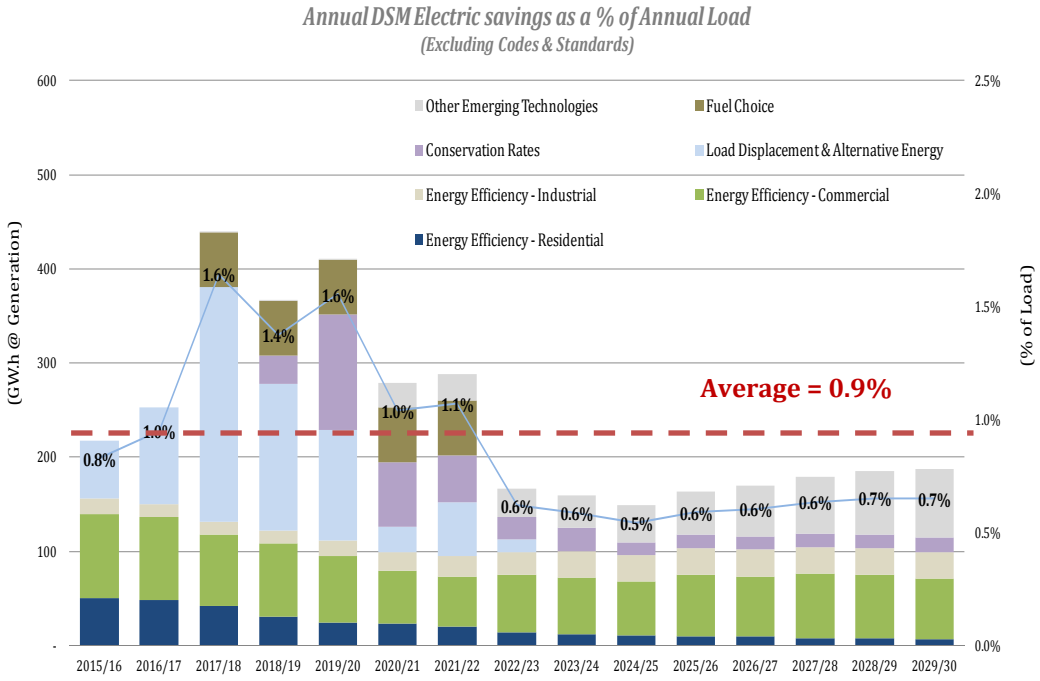


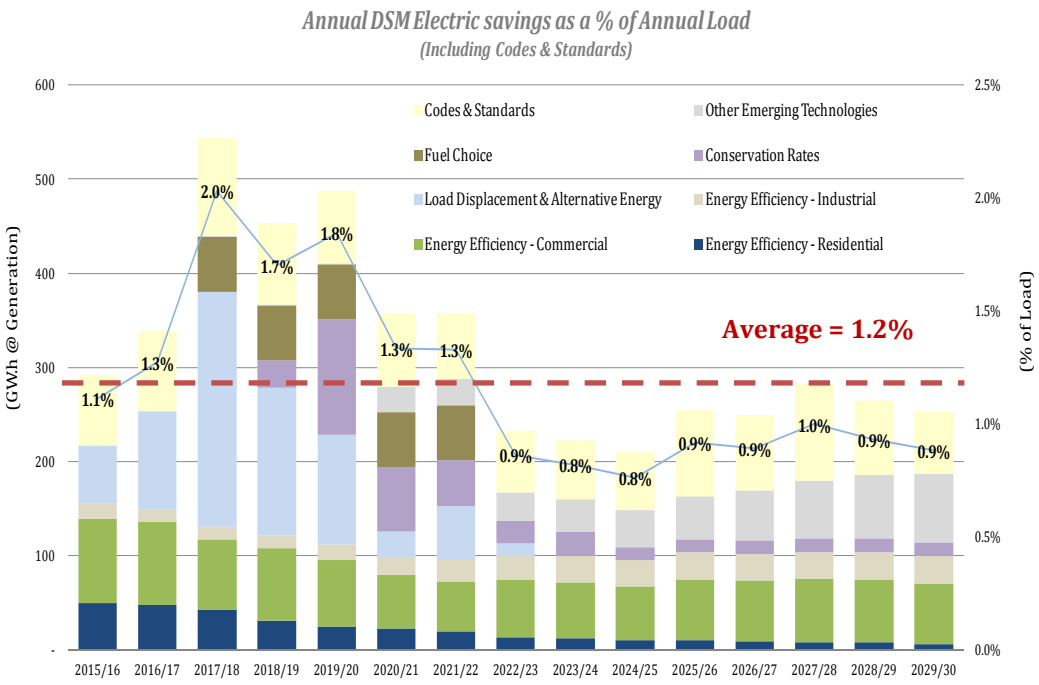
Note: Total DSM Natural Gas savings per the above graph includes forecast savings from program impacts and Codes, Standards and Regulations
Note: The above graph reflects a percentage of volume calculation that excludes the natural gas consumption of both Manitoba Hydro Power Stations and Special Contracts in the volume forecast.
Source of Natural Gas Volume Forecast: 2015 Natural Gas Volume Forecast

Annual Electric DSM Savings as a % of Annual Load

The following charts depict Manitoba Hydro's annual electric DSM efforts in relation to annual electric load growth.

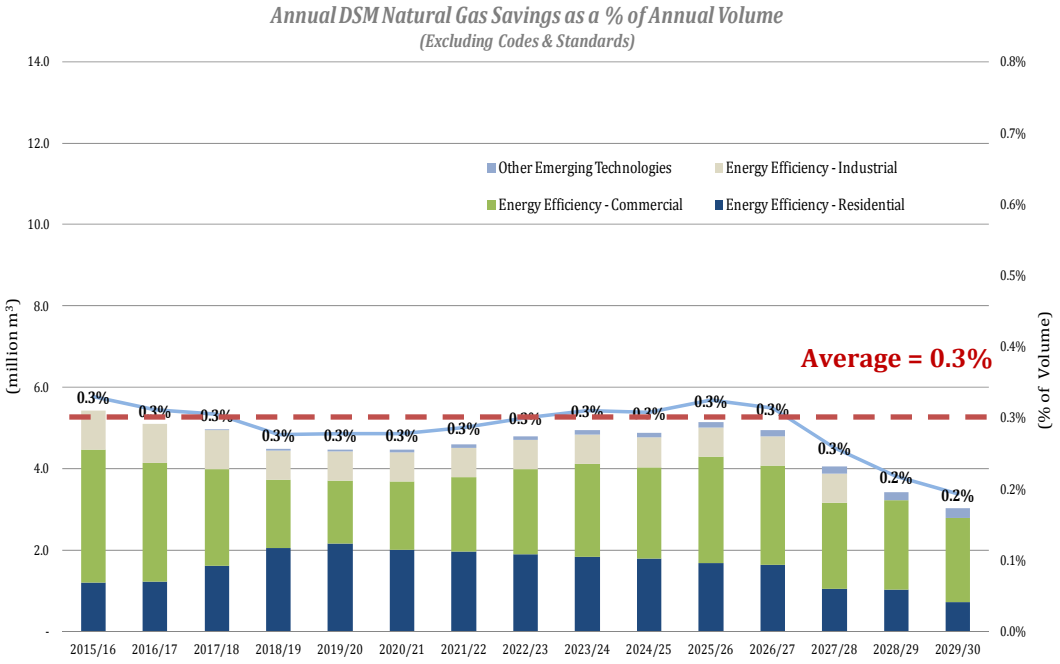


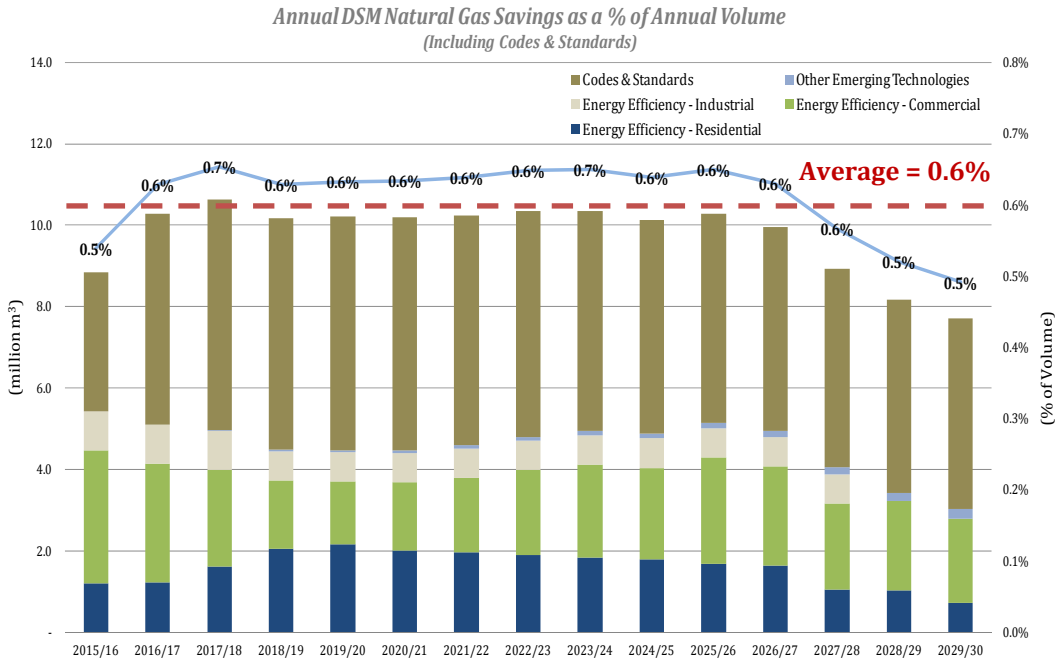


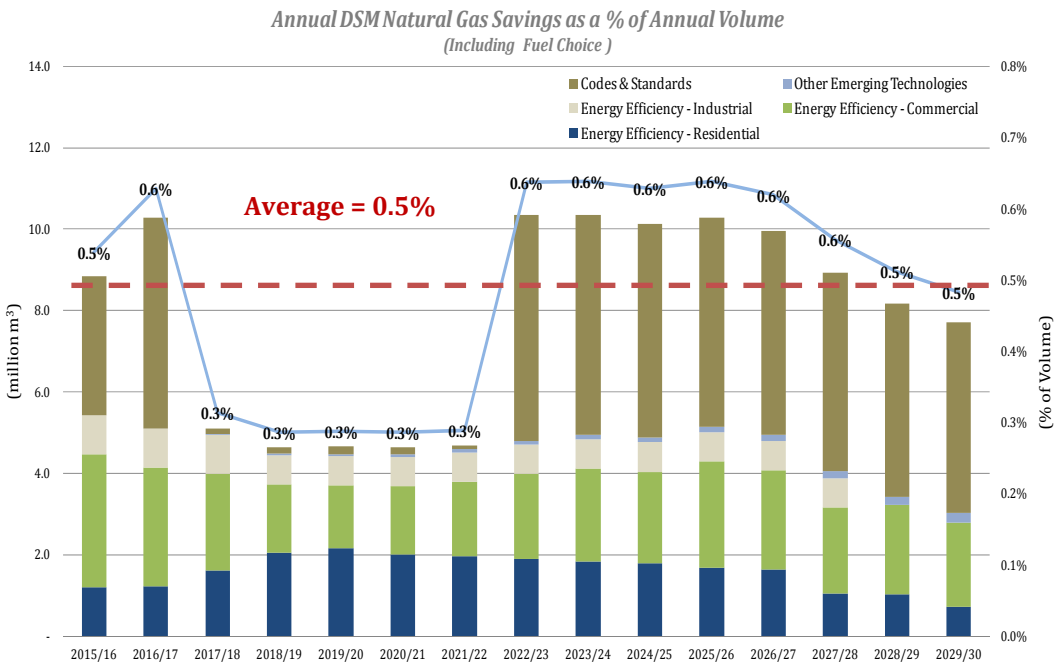

Annual DSM Electric savings as a % of Annual Load
(Including Codes & Standards)
Codes & Standards
Other Emerging Technologies
Fuel Choice
Conservation Rates
Load Displacement & Alternative Energy
Energy Efficiency - Industrial
Energy Efficiency - Commercial
Energy Efficiency - Residential
Average = 1.2%
(GWh @ Generation)
(% of Load)
600
500
400
300
200
100
-
2.5%
2.0%
1.5%
1.0%
0.5%
0.0%
1.1%
1.3%
2.0%
1.7%
1.8%
1.3%
1.3%
0.9%
0.8%
0.8%
0.9%
0.9%
1.0%
0.9%
0.9%
2015/16
2016/17
2017/18
2018/19
2019/20
2020/21
2021/22
2022/23
2023/24
2024/25
2025/26
2026/27
2027/28
2028/29
2029/30

Annual Natural Gas DSM Savings as a % of Annual Volume

The following charts depict Manitoba Hydro's annual natural gas DSM efforts in relation to annual natural gas volume growth.



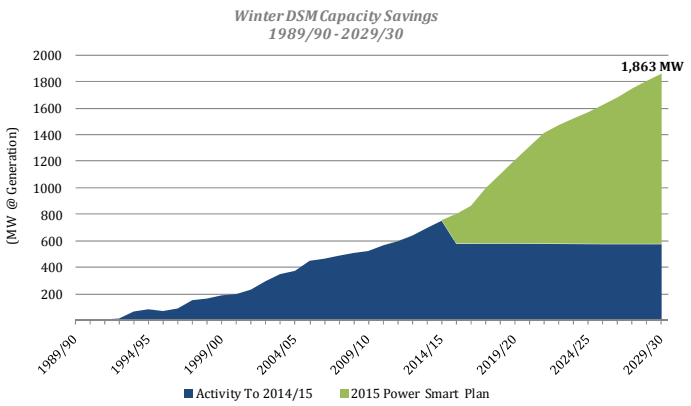


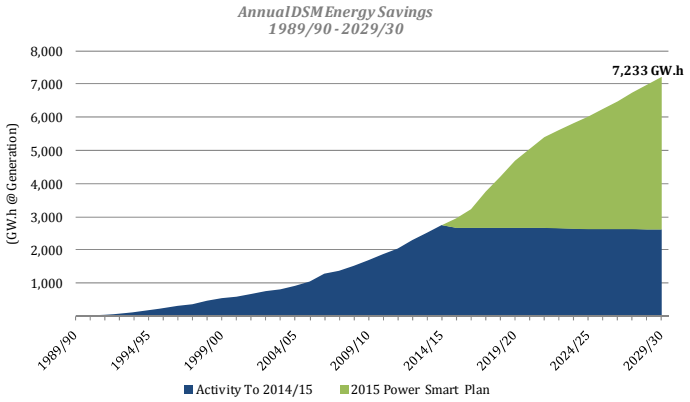


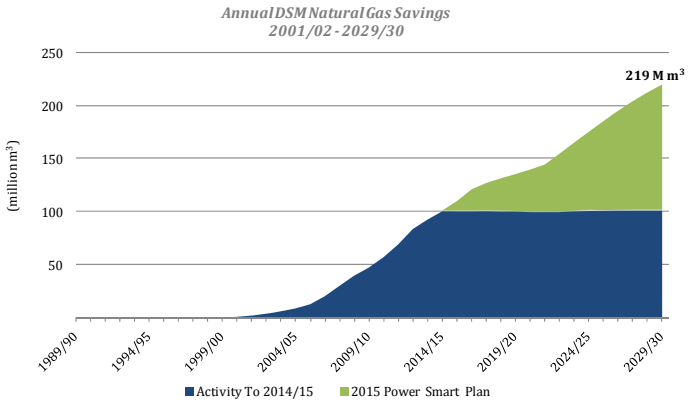
Note: The above graphs reflect a percentage of volume calculation that excludes the natural gas consumption of both Manitoba Hydro Power Stations and Special Contracts in the volume forecast.

Combined with energy savings achieved to date, total electrical savings of 1,863 MW and 7,233 GW.h and total natural gas savings of 219 million cubic metres will be realized by 2029/30. These combined energy savings are expected to result in an overall reduction of greenhouse gas emissions of 5.3 million tonnes by 2029/30. This activity represents 25.0% of the estimated electric load forecast and 12.8% of the estimated natural gas volume forecast by 2029/30.

The following charts graphically represent the capacity, electric energy and natural gas energy savings achieved to date and the savings anticipated from future DSM activity for the 2015 Power Smart Plan:







The following table shows detailed DSM savings associated with the 2015 Power Smart Plan by sector to 2029/30.

Electric and Natural Gas DSM Savings
2015/16 - 2029/30

	Winter Capacity (MW)		Annual Energy (GW.h)		Annual Energy (million m^3)		
Residential							
New Home Program	7.3		16.9		5.4		
Home Insulation Program	14.1		28.2		7.2		
Water and Energy Saver Program	2.6		14.5		1.6		
Affordable Energy Program							
Affordable Energy Program - Insulation	12.8		38.8		6.2		
Affordable Energy Program - Furnace	n/a		n/a		0.0		
Affordable Energy Program - Total	12.8		38.8		6.2		
Refrigerator Retirement Program	1.5		14.6		-		*i*
Drain Water Heat Recovery Initiative	0.2		1.7		n/a		
Residential LED Lighting Program	3.0		9.7		-		*i*
Community Geothermal Program	28.2		56.4		n/a		
Residential Programs Total (@ Meter)	69.8	8%	180.7	6%	20.5	41%	
Customer Service Initiatives / Financial Loan Programs							
Power Smart Residential Loan	3.3		6.4		3.9		
Power Smart PAYS Financing	1.5		3.0		0.0		
Residential Earth Power Loan	8.0		15.9		1.4		
Residential CSI / Financial Loan Programs Total (@ Meter)	12.7	1%	25.3	1%	5.4	11%	
Commercial							
Commercial Lighting Program	99.0		382.5		-		*i*
LED Roadway Lighting Conversion Program	7.8		52.0		n/a		
Commercial Building Envelope - Windows Program	12.7		26.0		4.0		
Commercial Building Envelope - Insulation Program	13.0		28.4		13.0		
Commercial Geothermal Program	38.2		76.4		n/a		
Commercial HVAC Program - Boilers	n/a		n/a		5.6		
Commercial HVAC Program - Chillers	0.0		8.6		n/a		
Commercial HVAC Program - CO2 Sensors	1.8		2.8		1.0		
Commercial HVAC Program - HRVs	5.0		10.2		2.9		
Commercial HVAC Program - Air Cooled Chillers	0.0		13.7		0.0		
Commercial HVAC Program - Water Heaters	n/a		n/a		1.3		
Commercial Custom Measures Program	5.9		25.9		1.9		
Commercial Building Optimization Program	3.9		19.1		4.9		
New Buildings Program	39.1		131.5		4.1		
Commercial Refrigeration Program	7.4		57.9		-		*i*
Commercial Kitchen Appliance Program	0.3		1.7		0.7		
Network Energy Management Program	0.4		3.3		-		*i*
Internal Retrofit Program	2.1		6.7		n/a		
Power Smart Energy Manager	0.9		4.0		0.4		
Power Smart Shops	0.9		3.4		0.1		
Commercial Programs Total (@ Meter)	238.3	28%	854.3	28%	39.8	80%	
Customer Service Initiatives / Financial Loan Programs							
Power Smart For Business PAYS Financing	0.0		0.0		0.0		
Commercial CSI / Financial Loan Programs Total (@ Meter)	0.0	0%	0.0	0%	0.0	0%	
Industrial							
Performance Optimization Program	38.8		307.9		n/a		
Natural Gas Optimization Program	n/a		n/a		10.1		
Industrial Programs Total (@ Meter)	38.8	4%	307.9	10%	10.1	20%	
Energy Efficiency Subtotal (@ Meter)	359.6	42%	1,368.2	45%	75.7	153%	
Load Management							
Curtailable Rate Program	143.5		n/a		n/a		
Load Management Programs Total (@ Meter)	143.5	17%	n/a	0%	n/a	0%	
Load Displacement & Alternative Energy							
Bioenergy Optimization Program	56.5		121.7		n/a		
Customer Sited Load Displacement	68.5		539.2		n/a		
Load Displacement & Alt. Energy Programs Total (@ Meter)	125.0	14%	661.0	22%	n/a	0%	
Conservation Rates							
Conservation Rates - Residential	17.2		141.7		n/a		
Conservation Rates - Commercial	25.9		213.7		n/a		
Conservation Rates Total (@ Meter)	43.0	5%	355.4	12%	n/a	0%	
Fuel Choice							
Fuel Choice	127.7		255.5		(27.7)		
Fuel Choice Total (@ Meter)	127.7	15%	255.5	8%	(27.7)	(56%)	
Other Emerging Technologies							
Residential Air Source Heat Pumps Program	0.0		5.5		n/a		
Residential Future Opportunities	15.2		73.1		n/a		
Residential Solar Photovoltaics Program (PV)	6.3		69.5		n/a		
Residential Solar Thermal Program - Water Heating	0.2		2.6		n/a		
Residential Solar Thermal Program - Pool Heating	0.0		1.9		1.4		
Commercial Future Opportunities	15.2		73.1		n/a		
Commercial Solar Photovoltaics Program (PV)	10.6		100.0		n/a		
Commercial Variable Speed and Frequency Drives	0.1		5.8		n/a		
Industrial Future Opportunities	15.7		75.8		n/a		
Other Emerging Technologies Total (@ Meter)	63.4	7%	407.4	13%	1.4	0%	
Program Impacts Total (@ Meter)	862.2	100%	3,047.5	100%	49.5	100%	
Interactive Effects					-9.1		
Codes, Standards and Regulations (@ Meter)	278.7		1,041.3		77.7		
Power Smart 2015/16 to 2029/30 Impacts (@ Meter)	1,141		4,089				
Power Smart 2015/16 to 2029/30 Impacts (@ Generation)	1,288		4,619		118		
Savings Achieved To 2014/15 (@ Meter)	508		2,314				
Savings Achieved To 2014/15 (@ Generation)	575		2,614		101		
Grand Total (@ Meter)	1,649		6,403				
Grand Total (@ Generation)	1,863		7,233		219		

i Natural gas interactive effects reported with overall total

2.1.2 Other Fuel Savings

Through funding from the Affordable Energy Fund, residential customers using heating sources other than natural gas and electricity are eligible to participate in the Home Insulation, Water & Energy Saver and Oil & Propane Furnace Replacement programs. The following table provides the oil and propane fuel savings estimated to be achieved through this funding.

It is estimated that savings of 407,200 litres of fuel oil and 172,600 litres of propane will be achieved from 2015/16 to 2029/30.

Affordable Energy Fund Other Fuel Savings
2015/16 - 2029/30
(000s, litres)

	2015/16	2016/17	2017/18 - 2029/30
Fuel Oil Savings			
Home Insulation Program	1.7	1.4	9.4
Water & Energy Saver Program	4.0	4.0	.0
Oil & Propane Furnace Replacement	64.4	64.4	257.8
Annual Fuel Oil Savings	70.2	69.9	267.2
Cumulative Fuel Oil Savings, 2015/16 - 2029/30	70.2	140.1	407.2
Propane Savings			
Home Insulation Program	7.1	6.4	47.0
Water & Energy Saver Program	2.1	2.1	.0
Oil & Propane Furnace Replacement	18.0	18.0	72.0
Annual Propane Savings	27.2	26.5	119.0
Cumulative Propane Savings, 2015/16 - 2029/30	27.2	53.7	172.6

2.1.3 Energy Efficient Codes, Standards & Regulation Savings

Many Canadian and U.S. electric utilities, including Manitoba Hydro, have been engaged in DSM activities for more than two decades. In addition to utility specific DSM programs, Manitoba Hydro's strategy to affect change in codes and standards involves being an aggressive and active participant and, in many cases, a driving force on a number of provincial and national energy efficiency codes and standards committees. These codes and standards are subsequently referenced in national and provincial regulations that mandate minimum energy performance levels for a variety of appliances, buildings and other energy consuming measures. The focus of Manitoba Hydro's efforts on these committees is to advance the progress of product efficiency improvements through the development of test methodologies that facilitate measurement and comparison of energy performance and provide for minimum energy performance levels that reasonably represent performance improvements available from commercially viable product advancements, which are then incorporated into Manitoba Power Smart programs, and subsequent energy efficiency regulations and building codes proposed by national and provincial regulators.

Not all codes and standards are regulated, with some codes and standards being developed for the purpose of supporting good business practices that assist customers in quantifying and comparing the energy performance of measures being considered for implementation. In these instances, Manitoba Hydro supports the adoption of such non-regulated codes and standards within its Power Smart programs.

Manitoba Hydro annually prepares a forecast of the expected influence of both regulated and non-regulated codes and standards, and since 1995 this forecast has been used to adjust Manitoba Hydro's system load forecast.

Strategic Steering Committee on Performance, Energy Efficiency and Renewables

Manitoba Hydro is a leading contributor on the Canadian Standards Association's Strategic Steering Committee on Performance, Energy Efficiency and Renewables (SCOPEER). This Canadian Standards Association committee, with participation from federal and provincial authorities, electric utilities, industry associations and equipment suppliers, provides oversight and governance for the process used to develop energy performance standards and establish minimum energy performance levels for energy consuming measures across most residential, commercial and industrial sectors. SCOPEER includes Technical Committees responsible for specific end-use technology areas, including Heating, Ventilation, Air Conditioning and Refrigeration Equipment (TC 401), Industrial Equipment (TC 402), Residential Equipment (TC 403), Lighting Equipment (TC 419), Solar Equipment (TC 420) and Energy Management (TC 422). Individual Technical Subcommittees operating within each of the Technical Committees are responsible for the development of specific standards related to the energy performance of end-use measures that are vetted and approved by the SCOPEER committee for adoption. Electric utilities, equipment suppliers and consumer reference these standards within their programs and specific areas of activity, while regulatory agencies at the national and provincial level adopt these standards and their associated minimum energy performance levels into energy efficiency regulations.

Energy Savings from Codes & Standards

In many markets, the most effective and permanent form of market transformation for energy efficient technologies and practices is the regulation of energy efficient codes and standards as such regulations ensures that customers do not revert to less efficient technologies/practices once the incentives and/or promotional activities are discontinued. Consequently, the process of achieving these changes is complex and lengthy as it involves many stakeholders, varying environmental and market conditions and market acceptance to ensure successful implementation.

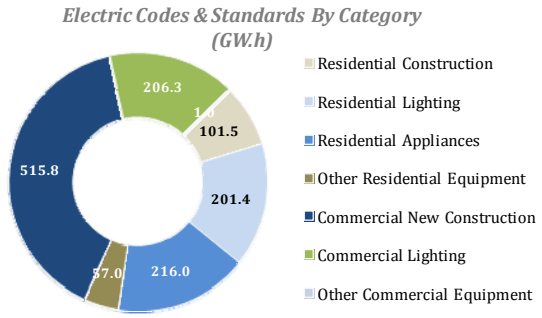
Efforts to achieve energy savings through Energy Efficient Codes and Standards initiatives are forecasted in the 2015 Power Smart Plan to achieve capacity savings of 353 MW, energy savings of 1299 GW.h and 87 million cubic metres of natural gas annually by 2029/30. As a result of these savings, a greenhouse gas emissions reduction of 1.0 million tonnes is expected by 2029/30.

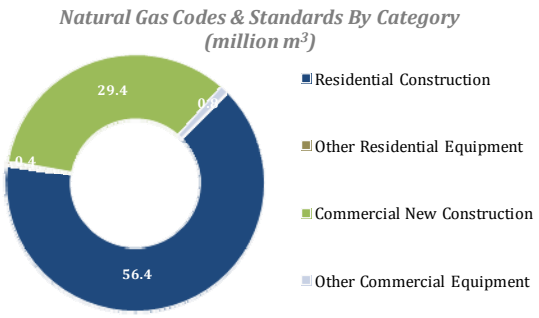
The following table and charts provide a summary of the planned energy savings in 2029/30 from codes and standards that currently implemented in energy efficiency regulation at the provincial and national level. Future DSM plans will provide updated forecasts of savings from codes and standards based on new information, such as the pending proposals being put forward by Natural Resources Canada for Amendments 13 and 14, which include both new or enhanced energy efficiency regulations for a variety of energy consuming measures.

Energy Savings from Codes & Standards
2015/16 - 2029/30

Code Category	Components	Energy and Demand Savings Winter MW	Energy and Demand Savings Annual GW.h	Natural Gas Annual millions m^3	CO2 Reductions Annual Tonnes
Residential Construction	Insulation, Windows, Pilot Light Gas Fire Place, Furnace, Heat Recovery Ventilation, Showerhead	32.2	101.5	56.4	175,644
Residential Lighting	General Service Lamps	74.7	201.4	-	135,934
Residential Appliances	Dishwashers, Clothes Washers, Clothes Dryers, Refrigerators, Freezers, Ranges, Stoves, Cooktops	35.9	216.0	-	145,769
Other Residential Equipment	Central Air Conditioning, Residential Furnace	0.0	57.0	0.4	39,220
Commercial New Construction	Various Building Code Amendments	153.4	515.8	29.4	403,966
Commercial Lighting	General Service Lamps, Exit Signs, Fluorescent Lamp Ballasts	56.7	206.3	-	139,240
Other Commercial Equipment	Commercial Furnace, Boiler and Spray Valves	0.2	1.0	0.8	2,214
Total @ Generation		353	1299	87	1,041,987

** Totals per above include savings attributed to specific Power Smart programs and thus differ from Codes and Standards savings reported in Appendices A.1, A.2 and C.1*





Status of Codes and Standards

The following table summarizes the status of changes to provincially and nationally regulated codes and standards included in the 2015 Power Smart Plan, including actual or expected dates for implementation.

For electricity, changes that account for 78% of total energy savings have been enacted and 22% are planned.

For natural gas, changes that account for 90% of total energy savings have been enacted and 10% are planned.

Status of Changes to Codes and Standards

Code Category	Components	Energy Annual GW.h	Natural Gas Annual million m^3	Level of Government	Expected Effective Date Enacted	Announced	Planned
Residential Construction	Building Code - Insulation	17.9	6.0	MB	2008		
Residential Construction	Building Code - Various measures	71.6	45.3	MB	2010		
Residential Construction	Building Code - Various measures	11.9	5.1	MB			2020
Residential Lighting	General Service Lamps (MEPS)	90.4	-	Federal	2014		
Residential Lighting	General Service Lamps (MEPS) (Future)	111.0	-	Federal			2025
Residential Appliances	Various appliances	181.7	-	Federal			
Residential Appliances	Various appliances (Future)	34.3	-	Federal			
Other Residential Equipment	Central Air Conditioning	51.3	-	Federal	2006		
Other Residential Equipment	Central Air Conditioning (Future)	5.7	-	Federal			2020
Other Residential Equipment	Residential Furnace	-	0.4	Federal / MB	2009		
Commercial New Construction	Building Code	416.0	25.5	MB	2016		
Commercial New Construction	Building Code (Future)	99.8	3.8	MB			2020
Commercial Lighting	General Service Lamps (MEPS)	20.9	-	Federal	2014		
Commercial Lighting	General Service Lamps (MEPS) (Future)	26.6	-	Federal			2025
Commercial Lighting	Exit Signs	1.9	-	Federal	2004		
Commercial Lighting	Fluorescent lamp ballasts (New / Reno)	157.0	-	Federal	2006 / 2010		
Other Commercial Equipment	Commercial Furnace	-	0.4	Federal / MB	2009		
Other Commercial Equipment	Commercial Boilers	-	0.1	Federal / MB		2017	
Other Commercial Equipment	Commercial Spray Valves	1.0	0.3	Federal / MB	2011		
Total (GW.h)		1299			1010	0.0	289
					78%	0%	22%
Total (million m^3)			87		78	0	9
					90%	0%	10%

Code, Standard & Regulation Descriptions

The following section describes each of the codes and standards listed in the Summary Table noted in Section 2.1.3 that have been taken into consideration when developing a forecast for projected savings.

Residential Construction

Building Code
Manitoba Building Code, amendment (PROVINCIAL)
Regulation 4/2008
Registered: January 11, 2008
Effective date: October 1, 2008

Manitoba Hydro has been offering the Power Smart New Home program to customers across the province since 2004. The New Home program promoted and offered incentives to customers for the installation of energy efficient technologies and building practices within the New Home construction industry. Manitoba Hydro worked closely with industry stakeholders like the Manitoba Home Builders' Association when developing requirements for the program. Specifically, the Power Smart New Home program has required and been promoting a minimum requirement for R20 insulation in the foundation walls of new homes since 2004.

Changes to Table 9.25.5.2. (Minimum Thermal Resistance for the Building Envelope) of the Manitoba Building Code (Regulation 127/2006) came into effect on October1, 2008. The changes related to the minimum requirement for insulation R-value for the interior and exterior foundation walls of new homes. The code change increased the minimum required insulation value from R12 to R20.

Building Code
Manitoba Building Code, amendment (PROVINCIAL)
Regulation 142/2010
Registered: October 4, 2010
Effective date: December 1, 2010

Manitoba Hydro has promoted energy efficient technologies and building practices within the residential new construction segment through delivery of the Power Smart New Home Program. When developing program requirements, Manitoba Hydro worked closely with industry stakeholders like the Manitoba Home Builders Association.

Through the delivery of the Power Smart Gold Home offering, Manitoba Hydro planned to aid the advancement of future building code by promoting and offering incentives to customers to build their home with Power Smart recommended technologies and construction practices. The Gold standard announced in 2007 required the use of heat recovery ventilators (HRV), 94 % AFUE furnaces, electronic ignition for natural gas fireplaces, R50 attic insulation, water efficient fixtures and many other building envelope improvements.

Effective December 1st, 2010, Manitoba implemented changes to the building and plumbing codes that increased energy and water efficiencies. These changes were the result of extensive consultations by the Office of the Fire Commissioner involving new homebuilders, contractors and technical experts. The new efficiencies incorporated into new construction and homes undergoing extensive renovations included:

- specifying minimum energy-efficiency requirements for windows,
- eliminating the pilot light in gas fireplaces,
- increasing the required level of attic insulation to R50,
- requiring a minimum 94 per cent fuel-efficiency rating for furnaces,
- specifying a mid-efficient heat-recovery ventilator, and
- introducing energy-modeling software that will allow builders to model alternatives to the code requirements.
- Requiring a maximum flow rate for primary showerheads to 1.75 GPM

Through its close working relations with key industry stakeholders and the Power Smart New Home Program offering, Manitoba Hydro succeeded in advancing these changes to the Manitoba Building code. In fact, a majority of the technologies adopted by the Manitoba Building Code for the December 1, 2010 update were part of the aforementioned Power Smart Gold Home standard requirements. Without the program providing information, education, training, and incentives for these technologies and building practices, the industry would have been less likely to adopt these technologies and transform the market. The program created demand for these technologies, provided builders an opportunity to gain experience using them, and provided trades and contractors training opportunities to advance their expertise and knowledge of the technologies.

<u>Building Code</u>
Manitoba Building Code, amendment (PROVINCIAL)
Regulation (Proposed)
Effective date: 2020

Manitoba Hydro is currently assessing the Power Smart New Home program. The program will promote and offer incentives to customers for the installation of energy efficient technologies and building practices within the New Home construction industry. Manitoba Hydro will work closely with industry stakeholders with the aim to build market acceptance of Power Smart New Home technologies for ease of adoption in the Manitoba Building Code in 2020. Manitoba Hydro has used a placeholder post-2020 Manitoba Building Code to account for future potential code savings beyond that realized through the Power Smart New Home program.

Residential Lighting

General Service Lamps
National Resources Canada (FEDERAL)
Amendment 12B to Energy Efficiency Regulations
Published: January 15, 2014 (Canada Gazette Part II)
Effective date(s): January 1st, 2014 - 75 to 100 watt equivalent lamps
December 31st, 2014 - 40 to 60 watt equivalent lamps

The Government of Canada announced in Amendment 12B to the Energy Efficiency Regulations, published on January 15, 2014 that they would introduce Minimum Energy Performance Standards (MEPS) for general service lamps in 2012. The consequent Regulations came into force in December 2013 and applied to 100 and 75 W bulbs manufactured on or after January 1, 2014, and to 60 and 40 W bulbs manufactured on or after December 31, 2014. The Regulations prohibit the importation and interprovincial shipment of non-compliant products. The Regulations provide for a number of alternatives to inefficient bulbs. Where no alternatives exist, exemptions are made.

The next iteration of residential lighting regulations has not been proposed. Manitoba Hydro has used a placeholder for Minimum Energy Performance Standard beginning in 2025 to account for future potential savings. This assumed MEP accounts for the impact of light-emitting diode (or equivalent) efficient lighting technology replacing the performance levels stipulated within Amendment 12B described above.

Residential Appliances

Manitoba Hydro is a key player on the Canadian Standards Association's Strategic Steering Committee on Performance, Energy Efficiency and Renewables (SCOPEER). This committee is responsible for changes to provincial and national performance standards and legislation which have resulted in the improvement of energy utilization of numerous appliances such as dishwashers, clothes washers & dryers, refrigerators and freezers, and ranges/stoves/cooktops. The forecast of the expected influence of regulated residential appliances includes the impact of existing Natural Resources Canada requirements. Additionally, placeholder standards are projected post-2020 to determine the impact of the next increment to these existing NRCAN standards. These placeholder standards are based on future harmonization with recently emerged or pending U.S. Department of Energy residential appliance standards.

Other Residential Equipment

<u>Central Air Conditioning</u>
National Resources Canada (FEDERAL)
Amendment 9 to Energy Efficiency Regulations
Test Standard: CAN/CSA-C656-05
Published: November 15, 2006 (Canada Gazette Part II)
Effective date(s): November 15, 2006

In November 2006, the CSA published a standard (C656-05) which specified mandatory MEPS applied to permanently installed 'air-source' air-conditioner and heat pumps. Equipment types include air conditioners and heat pumps that are single package and split system, single and three-phase, with rated capacity of less than 19 kW (65,000 Btu/h). For air conditioners, a minimum SEER rating of 13 was mandated.

Manitoba Hydro provides a fixed interest finance plan that may be used for renovations including central air, mid-efficient natural gas/electric furnaces and water heaters, direct vent natural gas fireplaces, security lights and fixtures under the Energy Finance Plan. Pre 2005, a minimum SEER rating of 10 for Air Conditioners was required for eligibility for financing under the plan. In order to comply with the forthcoming national standard, Manitoba Hydro raised the minimum SEER to 13 for eligibility of financing in October, 2005; approximately one year earlier.

The forecast of post-2020 increments to the above central air conditioning MEPS determines the impact of the next increment to these existing NRCAN standards. Future placeholder standards were based on future harmonization with U.S. Department of Energy residential central air conditioner standards.

Residential High Efficiency Furnace
National Resources Canada (FEDERAL)
Amendment 10 to Energy Efficiency Regulations
Published: December 24, 2008 (Canada Gazette Part II)
Effective date: December 31, 2009

On December 12, 2008 the Federal Government amended the Energy Act to require increased efficiency requirements for replacement gas (natural gas and propane) furnaces and boilers. Effective December 31, 2009 replacement furnaces up to 225 000 Btu/h sold in Canada are required to have a minimum AFUE of 90%.

Manitoba Hydro played a material role in the amendment of the Federal Energy Act. Manitoba Hydro staff assisted the Federal Government by providing technical and market data regarding the heating market in Manitoba and comments to the proposed Amendment during the consultation process. Power Smart Programs such as the Residential Loan and the High Efficiency Furnace and Boiler Rebate influenced the Manitoba market to the point that 80% of all equipment installed in 2009 was high efficiency products, thus making the Amendment acceptable to the industry and to consumers.

The Energy Act (PROVINCIAL)
Regulation 181/2009
Published: November 12, 2009
Effective date: December 30, 2009

On November 12, 2009 the Manitoba Government passed a regulation under the Energy Act to require increased efficiency requirements for replacement gas (natural gas and propane) furnaces and boilers. Effective December 30, 2009 replacement furnaces up to 225 000 Btu/h sold in Manitoba are required to have a minimum AFUE of 92%.

Manitoba Hydro played a major role in the development of the Provincial Regulation. Manitoba Hydro staff assisted the Province by providing technical and market data regarding the heating market, hosting an industry consultation with contractors and other interested parties, preparing a formal market impact study, and providing general guidance to regulatory staff. Power Smart Programs such as the Residential Loan and the High Efficiency Furnace and Boiler Rebate influenced the market to the point that 80% of all equipment installed in 2009 was high efficiency products, thus making regulation acceptable to the industry.

Commercial New Construction

Building Code

The national commitment to update the 1997 National Energy Code for Buildings (NECB) was initiated in Manitoba by the Energy Code Advisory Committee (ECAC) which was led by Manitoba Hydro. Manitoba Hydro also chaired the national Building Energy Code Collaborative (BECC), which was formed in response to the recommendations provided by ECAC. As a result of the work done by BECC, formal support was provided by jurisdictions across Canada to undertake the work to update the 1997 NECB and a national working group was formed to conduct the detailed work for updating the code. Manitoba's Minister of Labour provided formal support that signaled Manitoba's intention to adopt the document once published, however the Province still moved forward with their own energy strategy and convened a sub-committee of the Building Standards Board of Manitoba to recommend Manitoba-based energy and water efficiency recommendations that could be implemented in advance of the release of the 1997 NECB.

In January 2011, the energy efficiency amendments developed for the Manitoba building code were approved by the Building Standards Board of Manitoba and the Minister of Labour. However, with the NECB already through its public consultation phase and targeting a release date of Fall 2011, it was decided to hold back on regulating the specific Manitoba amendments so that a review and implementation of the NECB could be implemented. The sub-committee that developed the Manitoba amendments was reconvened in fall of 2012 with the task of reviewing the NECB and determining its applicability to the Manitoba market. Once again, Manitoba Hydro played a key role with several Power Smart staff contributing to this process. The sub-committee provided a recommendation that was formally adopted with minor adjustments in the December of 2013 for implementation and enforcement in December of 2014.

Manitoba Hydro staff continues to contribute to the national process for the development of the 2015 edition of the NECB and several Customer Engineering Services staff members formally attend regular code development meetings to ensure Manitoba Hydro objectives are met. Manitoba Hydro staff are also members of the Manitoba Building Standards Board Sub-Committee on Energy and Water Efficiency, which is responsible for recommending that the Province adopt the 2011 NECB and creation of additional recommendations specific to Manitoba that will be incorporated as amendments.

Manitoba Hydro continues to assess the New Buildings program. Commercial building code savings realized over the term beyond that of the New Buildings program have also been accounted for. Manitoba Hydro has used a placeholder post-2020 Building Code which reflects current regulatory intentions beyond the 2011 NECB described above.

Commercial Lighting

Since 1992, Manitoba Hydro has been actively promoting energy efficient lighting technologies for commercial applications. Activities involved in developing lighting standards include:

- Collaboration with other utilities, identify necessary research
- Work with Canadian Electrical Association
- Liaise with manufacturers to encourage the development and improvement of energy efficient lighting
- Product testing
- Liaise with National Research Council
- Participation on the CSA Standards Setting Committee
- Participation on the Canadian Lighting Industry Collaborative

<u>General Service Lamps</u>
National Resources Canada (FEDERAL)
Amendment 12B to Energy Efficiency Regulations
Published: January 15, 2014 (Canada Gazette Part II)
Effective date(s): January 1st, 2014 - 75 to 100 watt equivalent lamps
December 31st, 2014 - 40 to 60 watt equivalent lamps

The Government of Canada announced in Amendment 12B to the Energy Efficiency Regulations, published on January 15, 2014 that they would introduce Minimum Energy Performance Standards (MEPS) for general service lamps in 2012. The consequent Regulations came into force in December 2013 and applied to 100 and 75 W bulbs manufactured on or after January 1, 2014, and to 60 and 40 W bulbs manufactured on or after December 31, 2014. The Regulations prohibit the importation and interprovincial shipment of non-compliant products. The Regulations provide for a number of alternatives to inefficient bulbs. Where no alternatives exist, exemptions are made.

The next iteration of commercial lighting regulations has not been proposed. Manitoba Hydro has used a placeholder for Minimum Energy Performance Standard beginning in 2025 to account for future potential savings. This assumed MEP accounts for the impact of light-emitting diode (or equivalent) efficient lighting technology replacing the performance levels stipulated within Amendment 12B described above.

Exit Signs
National Resources Canada (FEDERAL)
Amendment 8 to Energy Efficiency Regulations
Test Standard: CAN/CSA-C860-01
Published: September 22, 2004 (Canada Gazette Part II)
Effective date: November 1, 2004

In September of 2004, Natural Resources Canada's (NRCan's) Office of Energy Efficiency (OEE) amended Canada's Energy Efficiency Regulations (the Regulations) in order to strengthen the minimum energy performance standard for internally lighted exit signs with the publication of Amendment 8 in Canada Gazette Part II. This standard contains voluntary minimum performance standards of 22 watts for signs 120 V or less, and 27 watts for signs greater than 120 V. These levels were harmonized with the National Building Code of Canada. The standard also addresses the visibility performance of the exit sign. To meet these standards, typically requires that LED technology be employed. In the area of LED lighting, the program supported these minimum efficiency levels for new exit signs with signs set at a level that only LED exit signs could meet.

Fluorescent lamp ballasts
National Resources Canada (FEDERAL)
Amendment 9 to Energy Efficiency Regulations
Test Standard: CAN/CSA-C654-M91
Published: November 15, 2006 (Canada Gazette Part II)
Effective date(s): November 15th, 2006 (New Construction Market)
April 1st, 2010 (Renovation Market)

In November of 2006, Natural Resources Canada's (NRCan's) Office of Energy Efficiency (OEE) amended Canada's Energy Efficiency Regulations (the Regulations) in order to strengthen the minimum energy performance standard for florescent lamp ballasts with the publication of Amendment 9 in Canada Gazette Part II. Manitoba Hydro's lighting initiative helped support this Federal code change that required fluorescent lamp ballasts meet a prescribed minimum energy performance standard in the new construction market in 2006 and the renovation market in 2010.

Other Commercial Equipment

Commercial High Efficiency Furnace
National Resources Canada (FEDERAL)
Amendment 10 to Energy Efficiency Regulations
Published: December 24, 2008 (Canada Gazette Part II)
Effective date: December 31, 2009

On December 12, 2008 the Federal Government amended the Energy Act to require increased efficiency requirements for replacement gas (natural gas and propane) furnaces and boilers. Effective December 31, 2009 replacement furnaces up to 225 000 Btu/h sold in Canada are required to have a minimum AFUE of 90%.

Manitoba Hydro played a material role in the amendment of Canada's Energy Efficiency Act. Manitoba Hydro staff assisted the Federal Government by providing technical and market data regarding the furnace market in Manitoba and comments to the proposed Amendment during the consultation process. Power Smart programs such as the Power Smart Residential Loan, the Residential High Efficiency Furnace and Boiler Rebate, and the Commercial HVAC Program - High Efficiency Furnace incentive all influenced market adoption; increasing market penetration of high efficiency furnaces in Manitoba commercial buildings from the pre-program average of 30% to 75% at program termination. Manitoba Hydro's involvement has expedited market transformation and thus facilitated the adoption of the federal efficiency regulation.

The Energy Act (PROVINCIAL)
Regulation 181/2009
Published: November 12, 2009
Effective date: December 30, 2009

On November 12, 2009 the Manitoba Government passed a regulation under the Energy Act to require increased efficiency requirements for replacement gas (natural gas and propane) furnaces and boilers. Effective December 30, 2009 replacement furnaces up to 225 000 Btu/h sold in Manitoba are required to have a minimum AFUE of 92%.

Manitoba Hydro played a material role in the development of the provincial efficiency regulation. Manitoba Hydro staff assisted the Manitoba Government by providing technical and market data, hosting an industry consultation with contractors and other interested parties, preparing a formal market impact study, and providing general guidance to regulatory staff. Power Smart programs such as the Residential Loan, the Residential High Efficiency Furnace and Boiler Rebate, and the Commercial HVAC Program - High Efficiency Furnace incentive all helped to expedite market adoption of high efficiency furnaces in Manitoba commercial buildings from the pre-program average of 30% to 75% at program termination. Manitoba Hydro's active involvement had expedited market transformation, and thus facilitated the adoption of the provincial efficiency regulation.

<u>Commercial Boilers</u>
National Resources Canada (FEDERAL)
Bulletin published: August 2010
Test Standard: HI BTS 2000, Rev 06.07 Method to Determine Efficiency of Commercial Space Heating Boilers
Proposed Effective date(s): March, 2015 (90% Min Efficiency Rating - New Construction Market)
March, 2015 (85% Min Efficiency Rating - Existing Buildings Market)

In August of 2010, Natural Resources Canada's (NRCan's) Office of Energy Efficiency (OEE) Natural Resources Canada (NRCan) proposed to amend Canada's ENERGY EFFICIENCY REGULATIONS (the Regulations) to require dealers to comply with minimum energy performance standards (MEPS) for commercial gas and oil-fired boilers, imported or shipped inter-provincially, for sale or lease in Canada. NRCan proposes that commercial packaged boilers meet minimum efficiency ratings of 90% for the New Construction mark and 85% for the Replacement Market, effective March, 2015.

Manitoba Hydro proposes that the Provincial Government enact regulations under The Energy Act, requiring a minimum performance level for all natural gas boilers sold to new Manitoba buildings. By April 1 2013, Manitoba Hydro proposes that all commercial boilers be condensing, with a minimum efficiency rating of 90%. This regulation is equivalent to the proposed federal regulation, but will be enacted two years earlier.

Manitoba Hydro will play a material role in the development of a provincial efficiency regulation for commercial natural gas boilers. Manitoba Hydro staff will assist the Manitoba Government by providing technical and market data, hosting an industry consultation with contractors and other interested parties, preparing a formal market impact study, and providing general guidance to regulatory staff. The Commercial HVAC Program will continue to expedite market adoption of high efficiency boilers in all commercial buildings from it pre-program average of 30% to an estimated 72% by April 2013, thus facilitating the adoption of a provincial performance standard two years earlier than the rest of Canada.

Manitoba Hydro proposes that the Provincial Government enact regulations under The Energy Act, requiring a minimum performance level for all natural gas boilers sold to existing Manitoba buildings. By March 2015, Manitoba Hydro proposes that all commercial boilers be condensing, with a minimum efficiency rating of 90%. This is approximately 5% higher than the proposed federal regulation requiring all boilers sold to be at least 85% efficient (near-condensing).

Manitoba Hydro will play a material role in the development of a provincial efficiency regulation for commercial natural gas boilers. Manitoba Hydro staff will assist the Manitoba Government by providing technical and market data, hosting an industry consultation with contractors and other interested parties, preparing a formal market impact study, and providing general guidance to regulatory staff. The Commercial HVAC Program will continue to expedite market adoption of high efficiency boilers in all commercial buildings from it pre-program average of 30% to an estimated 75% by March 2015, thus facilitating the adoption of a higher performance standard in Manitoba.

<u>Commercial Pre Rinse Spray Valve</u>
Manitoba Plumbing Code
Regulation 32/2011
Adoption of National Plumbing Code of Canada 2010
Published: March 28, 2011 The Buildings and Mobile Homes Act (C.C.S.M. c. B93)
Effective date: April 1, 2011

On April 1, 2011 the Manitoba Government repealed the Manitoba Plumbing Code, Manitoba Regulation 128/2006 and adopted the National Plumbing Code of Canada 2010 issued by the Canadian Commission on Buildings and Fire Codes, National Research Council Canada. The code states that the maximum flow rate for a pre-rinse spray valve not exceed 6.1 litres per minute (1.60 gallons per minute). The Power Smart Rinse & Save Program influenced market adoption; converting the Manitoba market to pre-rinse spray valves with equal or higher energy efficiency than the code. Manitoba Hydro's involvement has expedited market transformation and thus facilitated the adoption of the code.

At an Industrial level, Manitoba Hydro undertakes codes and standards development work with the following organizations:

- Natural Resources Canada (NRCAN)
- Province of Manitoba
- Canadian Standards Association (CSA), including BC Hydro, Hydro Quebec, Ontario Power Authority, Ontario Ministry of Energy, etc)
- Centre for Energy Advancement through Technological Innovation (CEATI)
- US Department of Energy (DOE)
- Institute of Electronic and Electrical Engineers (IEEE)
- International Electrotechnical Commission (IEC)
- American Council for an Energy-Efficient Economy (ACEEE)
- Electric Power Research Institute (EPRI)
- Energy Solutions Center (ESC)
- American Society of Heating, Refrigeration and Air-Conditioning Engineers (ASHRAE)
- Canadian Gas Association (CGA)

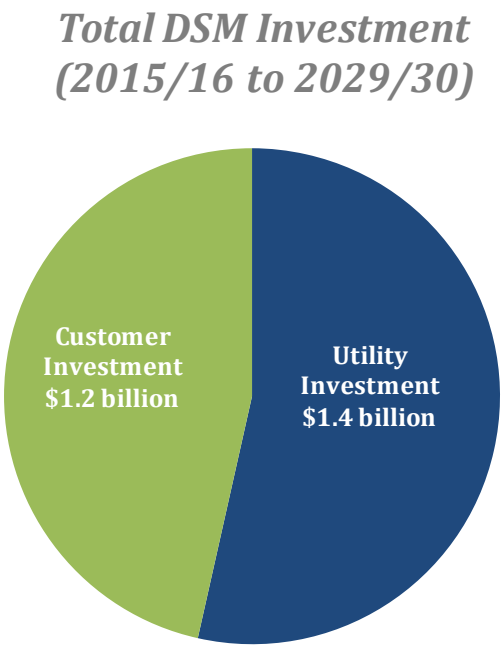
This work pertains primarily to industrial and commercial equipment that incorporates or applies to electric motors, variable speed drives, air compressors, compressed air systems, fans, pumps, transformers, power quality systems, battery charges, uninterruptible power supplies, lighting systems, refrigeration, heating, ventilation and air conditioning systems, and building envelope incorporating both natural gas and electric supply.

Areas of involvement include, test methods for determination of energy efficiency, performance standards, application guides for efficiency test methods and performance standards and repair standards (to maintain efficiency). Industrial codes and standards are often developed as non-regulated mechanisms designed to support good practices in the selection, operation and maintenance of energy consuming measures. As such, these codes and standards are incorporated into Manitoba Hydro's Industrial Power Smart programs supporting the savings objectives of these programs.

2.2 DSM Investment

2.2.1 Total Investment

Manitoba Hydro's current 15 year DSM plan involves a investment of approximately $2.6 billion (utility investment of $1.4 billion and customer investment of an estimated $1.2 billion, excluding cost impacts of changes to codes and standards).



Including investments to date, it is expected that by 2029/30, a cumulative investment of achieving the energy savings will have been $3.4 billion (utility investment of $2.0 billion and customer investment of an estimated $1.4 billion, excluding cost impacts of changes to codes and standards).

2.2.2 Utility Investment

The following table provides the cumulative electric and natural gas internal DSM investment totals to 2029/30 broken down by market sector and cost basis. Including other internal DSM investments, it is expected that by 2029/30, an additional cumulative utility investment amount of $1.4 billion will have been spent on Power Smart programs and initiatives. Including investments to date, it is expected that by 2029/30, a cumulative investment of achieving the energy savings will have been $2.0 billion.

Internal DSM Utility Investment
2015/16 - 2029/30

	Electric Cumulative Utility Costs (Millions $)		Natural Gas Cumulative Utility Costs (Millions $)		Total Cumulative Utility Costs (Millions $)		
Residential							
New Home Program	$2.6		$0.4		$3.0		
Home Insulation Program	$16.7		$14.8		$31.5		
Water and Energy Saver Program	$4.6		$1.9		$6.5		
Affordable Energy Program							
Affordable Energy Program - Insulation	$34.4		$43.5		$78.0		**
Affordable Energy Program - Furnace	-		$20.0		$20.0		**
Affordable Energy Program - Total	$34.4		$63.6		$98.0		**
Refrigerator Retirement Program	$11.3		-		$11.3		
Drain Water Heat Recovery Initiative	$0.6		-		$0.6		
Residential LED Lighting Program	$4.7		-		$4.7		
Community Geothermal Program	$27.8		-		$27.8		
Residential Programs Total	$102.7	9%	$80.7	56%	$183.4	14%	
Commercial							
Commercial Lighting Program	$109.6		-		$109.6		
LED Roadway Lighting Conversion Program	$56.2		-		$56.2		
Commercial Building Envelope - Windows Program	$11.1		$8.2		$19.3		
Commercial Building Envelope - Insulation Program	$12.1		$25.5		$37.5		
Commercial Geothermal Program	$44.3		-		$44.3		
Commercial HVAC Program - Boilers	-		$3.5		$3.5		
Commercial HVAC Program - Chillers	$1.8		-		$1.8		
Commercial HVAC Program - CO2 Sensors	$1.2		$1.5		$2.7		
Commercial HVAC Program - HRVs	$3.5		$2.4		$6.0		
Commercial HVAC Program - Air Cooled Chillers	$6.9		-		$6.9		
Commercial HVAC Program - Water Heaters	-		$1.7		$1.7		
Commercial Custom Measures Program	$10.7		$3.0		$13.7		
Commercial Building Optimization Program	$3.2		$6.7		$9.9		
New Buildings Program	$16.5		$3.8		$20.3		
Commercial Refrigeration Program	$9.7		-		$9.7		
Commercial Kitchen Appliance Program	$0.2		$0.5		$0.7		
Network Energy Management Program	$0.5		-		$0.5		
Internal Retrofit Program	$6.4		-		$6.4		
Power Smart Energy Manager	$0.5		$0.2		$0.6		
Power Smart Shops	$2.1		$0.0		$2.1		
Commercial Programs Total	$296.4	26%	$57.0	39%	$353.4	27%	
Industrial							
Performance Optimization Program	$144.4		-		$144.4		
Natural Gas Optimization Program	-		$6.0		$6.0		
Industrial Programs Total	$144.4	12%	$6.0	4%	$150.4	12%	
Energy Efficiency Subtotal	$543.4	47%	$143.8	100%	$687.2	53%	
Load Management							
Curtailable Rate Program	$103.5		-		$103.5		
Load Management Programs Total	$103.5	9%	-	0%	$103.5	8%	
Load Displacement & Alternative Energy							
Bioenergy Optimization Program	$38.7		-		$38.7		
Customer Sited Load Displacement	$99.5		-		$99.5		
Load Displacement & Alt. Energy Programs Total	$138.3	12%	-	0%	$138.3	11%	
Conservation Rates							
Conservation Rates - Residential	$13.4		-		$13.4		
Conservation Rates - Commercial	$17.6		-		$17.6		
Conservation Rates Total	$30.9	3%	-	0%	$30.9	2%	
Fuel Choice							
Fuel Choice	$54.6		-		$54.6		
Fuel Choice Total	$54.6	5%	-	0%	$54.6	4%	
Other Emerging Technologies							
Residential Air Source Heat Pumps Program	$2.2		-		$2.2		
Residential Future Opportunities	$45.9		-		$45.9		
Residential Solar Photovoltaics Program (PV)	$59.8		-		$59.8		
Residential Solar Thermal Program - Water Heating	$1.5		-		$1.5		
Residential Solar Thermal Program - Pool Heating	$0.5		$0.6		$1.1		
Commercial Future Opportunities	$49.6		-		$49.6		
Commercial Solar Photovoltaics Program (PV)	$71.9		-		$71.9		
Commercial Variable Speed and Frequency Drives	$3.4		-		$3.4		
Industrial Future Opportunities	$54.4		-		$54.4		
Other Emerging Technologies Total	$289.2	25%	$0.6	0%	$289.8	22%	
Program Impacts Total	$1,160.0	100%	$144.4	100%	$1,304.4	100%	
Program Support and Contingency Costs	$71.2		$16.2		$87.4		
Power Smart Investment Total, 2015/16- 2029/30	$1,231.2		$160.7		$1,391.8		
Other Internal DSM Investments							
Afforedable Energy Fund	$1.2		$0.6		$1.9		
Cumulative Investment Total, 2015/16 - 2029/30	$1,232.4		$161.3		$1,393.7		
Spent to 2014/15	$463.8		$128.7		$592.5		
Cumulative Investment Total, 1989/90 - 2029/30	$1,696.3		$290.0		$1,986.2		

*** Includes all Affordable Energy Fund Expenditures and Furnace Replacement Program*

The following table outlines the total projected DSM budget including all internal sources of funding to 2029/30. A total investment of $1.4 billion is planned for the period of 2015/16 to 2029/30.

Forecasted Internal DSM Budget
2015/16 - 2029/30
(Millions $)

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	Total
Electric DSM																
Electric Power Smart	61.6	57.5	97.3	93.3	89.0	91.3	95.4	71.9	67.0	70.5	76.0	81.2	87.6	94.2	96.1	1,229.8
Affordable Energy Fund	1.7	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	2.1
Annual Electric Budget	$63.3	$57.6	$97.4	$93.3	$89.1	$91.3	$95.4	$71.9	$67.0	$70.5	$76.0	$81.2	$87.6	$94.2	$96.1	$1,231.8
Natural Gas DSM																
Natural Gas Power Smart	10.3	12.7	10.7	9.4	9.5	9.3	9.4	8.8	9.3	9.2	9.3	9.2	8.2	7.7	4.8	138.0
Affordable Energy Fund	2.9	0.2	0.2	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	3.3
Furnace Replacement Budget	2.4	2.5	2.6	2.6	2.6	2.5	2.3	2.1	0.1	0.1	0.1	0.1	0.1	0.1	-	20.0
Annual Natural Gas Budget	$15.6	$15.4	$13.4	$12.1	$12.1	$11.9	$11.7	$11.0	$9.4	$9.3	$9.4	$9.3	$8.3	$7.8	$4.8	$161.3
Oil and Propane DSM																
Affordable Energy Fund	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	0.6
Annual Oil and Propane Budget	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	-	-	-	$0.6
Manitoba Hydro Annual Budget	$79.0	$73.1	$110.9	$105.5	$101.3	$103.2	$107.1	$82.9	$76.4	$79.8	$85.4	$90.5	$95.9	$102.0	$100.8	
Cumulative Investment 2015/16 - 2029/30	$79.0	$152.1	$263.0	$368.4	$469.7	$573.0	$680.1	$763.0	$839.4	$919.1	$1,004.5	$1,095.0	$1,190.9	$1,292.9	$1,393.7	$1,393.7

Note: Figures may not add due to rounding

Including investments to date, it is expected that by 2029/30, a cumulative investment of achieving the energy savings will have been $2.0 billion, $1.7 billion of the costs are funded through the Corporation's Power Smart electricity budget, $239 million from the Power Smart natural gas budget, $35 million from the Affordable Energy Fund, and $31 million from the Furnace Replacement budget for targeting furnace replacement.

Total Internal DSM Budget
1989/90 - 2029/30
(Millions $)

	Expenditures to date 1989/90 - 2014/15	15 yr planning horizon 2015/16 - 2029/30	Total 1989/90 - 2029/30
Electric DSM			
Electric Power Smart	451.1	1,229.8	1,680.9
Affordable Energy Fund	12.3	2.1	14.3
Annual Electric Budget	$463.4	$1,231.8	$1,695.2
Natural Gas DSM			
Natural Gas Power Smart	101.2	138.0	239.2
Affordable Energy Fund	16.5	3.3	19.8
Furnace Replacement Budget	10.9	20.0	31.0
Annual Natural Gas Budget	$128.7	$161.3	$290.0
Oil and Propane DSM			
Affordable Energy Fund	0.5	0.6	1.1
Annual Oil and Propane Budget	$0.5	$0.6	$1.1
Cumulative Investment 1989/90 - 2029/30	$592.5	$1,393.7	$1,986.2

Note: Figures may not add due to rounding

Affordable Energy Fund

The Affordable Energy Fund is an internal fund established as a result of the Winter Heating Cost Control Act. The purpose of the Fund is to provide support for programs and services that achieve specific objectives outlined under the Act including encouraging energy efficiency and conservation through programs and services for rural and northern Manitobans, low income customers and seniors and encouraging the use of alternative energy sources such as renewable energy.

Manitoba Hydro established the Affordable Energy Fund following the passing of the Winter Heating Cost Control Act on November 20, 2006 in the Manitoba Legislature. The Affordable Energy Fund supports Manitoba Hydro's sustainable development initiatives.

The following projects and associated funding levels have been approved for support by the Affordable Energy Fund. As of March 31st, 2015 approximately $32.0 million of the Affordable Energy Fund had been spent, leaving the remaining $6.1 million.

Affordable Energy Fund Budget
(Millions $)

	Total Budget	Expeditures to Date	Remaining Total Budget
Affordable Energy Program	23.6	19.7	3.8
Geothermal Support	1.6	1.4	0.2
Community Support and Outreach	1.0	0.8	0.2
Oil and Propane Heated Homes	0.3	0.3	-
Special Projects			
Residential ecoENERGY Audits	0.5	0.5	-
Oil and Propane Furnace Replacement	0.5	0.2	0.4
Solar Water Heaters	0.3	0.3	0.0
Power Smart Residential Loan	2.5	1.9	0.5
Oil and Propane Heated Homes - Additional funding	0.3	0.1	0.2
Spruce Wood Loggers	0.2	-	0.2
Community Energy Development			
ecoENERGYProgram Funding	4.1	4.1	-
Power Smart PAYS Financing Program	0.4	0.0	0.4
Subtotal	$35.2	$29.3	$5.9
Energy & Resource Fund *	0.8	0.8	-
Manitoba Electric Bus *	1.2	1.1	0.1
FortWhyte EcoVillage *	0.1	0.1	-
Diesel Community Green Pilot Demonstration *	0.4	0.3	0.2
Métis Generation Fund *	0.5	0.5	-
TOTALS	$38.2	$32.0	$6.1

Note: Non Demand Side Management Budget*
Figures may not add due to rounding

The following table identifies the programs and associated funding levels that the Affordable Energy Fund will support over the Power Smart Planning horizon.

Affordable Energy Fund Budget
(Millions $)

	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27 - 2029/30	Total
Affordable Energy Program	3.8	-	-	-	-	-	-	-	-	-	-	-	3.8
Geothermal Support	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-	-	-	-	0.2
Community Support and Outreach	0.2	-	-	-	-	-	-	-	-	-	-	-	0.2
Oil and Propane Heated Homes	-	-	-	-	-	-	-	-	-	-	-	-	-
Special Projects													
Residential ecoENERGY Audits	-	-	-	-	-	-	-	-	-	-	-	-	-
Oil and Propane Furnace Replacement	0.1	0.1	0.1	0.1	0.1	0.1	-	-	-	-	-	-	0.4
Solar Water Heaters	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
Power Smart Residential Loan	0.2	0.2	0.2	-	-	-	-	-	-	-	-	-	0.5
Oil and Propane Heated Homes - Additional funding	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Spruce Wood Loggers	0.2	-	-	-	-	-	-	-	-	-	-	-	0.2
Community Energy Development													
ecoENERGYProgram Funding	-	-	-	-	-	-	-	-	-	-	-	-	-
Power Smart PAYS Financing Program	0.1	0.1	0.1	0.1	0.0	0.0	-	-	-	-	-	-	0.4
Subtotal	$4.6	$0.4	$0.4	$0.2	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$5.9
Energy & Resource Fund *	-	-	-	-	-	-	-	-	-	-	-	-	-
Manitoba Electric Bus *	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	0.1
FortWhyte EcoVillage *	-	-	-	-	-	-	-	-	-	-	-	-	-
Diesel Community Green Pilot Demonstration *	0.2	-	-	-	-	-	-	-	-	-	-	-	0.2
Métis Generation Fund *	-	-	-	-	-	-	-	-	-	-	-	-	-
Annual Budget	$4.8	$0.4	$0.4	$0.2	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$6.1
Cumulative Budget 2015/16 - 2029/30	$4.8	$5.2	$5.6	$5.7	$5.9	$6.0	$6.0	$6.1	$6.1	$6.1	$6.1	$6.1	$6.1

Note: Annual interest accruals are not included in the above forecast
Figures may not add due to rounding

Affordable Energy Program

The Affordable Energy Fund supports the Affordable Energy Program by targeting low-income Manitobans through an individual, community and neighbourhood approach.

Geothermal Support

The Affordable Energy Fund provides funding to support the application of geothermal technology. A portion of the fund is being used to subsidize the interest rate for Residential Earth Power Loan program participants from 6.5% to 4.9% for the first five years of the loan term.

Community Support and Outreach

The Affordable Energy Fund provides funding for additional resources for the purpose of encouraging rural and northern customers to participate in Power Smart initiatives.

Oil and Propane-Heated Homes

The Affordable Energy Fund provides incentives to allow customers with wood, oil or propane heating to participate in Power Smart programs. The estimated savings of the other fuel types resulting from the installation of insulation in customer homes are provided in the next section of this report. (Note: Additional funding provided through the special projects category)

Special Projects

Residential Energy Assessment Service (ecoENERGY Audits)

The Affordable Energy Fund contributes the incremental costs associated with providing Manitoba Hydro's In-home Energy Assessment service under the Federal ecoENERGY Retrofit program to rural and northern Manitobans.

Oil & Propane Furnace Replacement

Manitoba Hydro extended the eligibility for the Power Smart Furnace Replacement Program to those customers upgrading an oil or propane furnace to a high efficiency electric or natural gas furnace.

Residential Solar Water Heating Program

Manitoba Hydro is partnering with Natural Resources Canada to deliver a residential solar water heating initiative in Manitoba. This initiative supports the application of solar domestic hot water pre-heating systems and the development of the local solar industry.

Power Smart Residential Loan

The Affordable Energy Fund provides funding to reduce the interest rate for the Power Smart Residential Loan from a cost recovery rate of 5.5% to a rate of 3.9%.

Oil and Propane-Heated Homes – Additional Funding

This initiative provides further funding to extend the eligibility of Power Smart programs to include homes currently heated by a source other than electricity and natural gas. As this additional funding is coming from a separate Affordable Energy Fund category than the original funding, it is tracked separately.

Spruce Wood Loggers

This initiative provides funding to support Spruce Wood Loggers in upgrading their operations to include pelletizing ground wood and waste sawdust material. The pellets would provide an alternative fuel for coal-fired boilers and potentially prevent some customers in close proximity to Spruce Wood Loggers from converting to electric boilers.

Community Energy Development

ecoENERGY Program Funding – Additional Funding

Additional funding has been allocated to support the cost of offering audits in Manitoba, involving a $100 subsidy for each audit plus the incremental cost of offering audits in rural and northern Manitoba.

Power Smart PAYS Financing Program

This initiative provides funding to reduce the interest rate for the PAYS financing program from the cost recovery rate to a rate of 3.9%.

Energy and Resource Fund

The Affordable Energy Fund provided funding to the Energy and Resource Fund. Managed by the First Peoples Economic Growth Fund, this joint initiative between the Government of

Manitoba and the Assembly of Manitoba Chiefs was created to maximize First Nations participation in Major Energy and Resource Projects.

Manitoba Electric Bus
Funding is provided to support the Manitoba Electric Bus Project; a joint initiative among the Province of Manitoba, Manitoba Hydro, Red River College, New Flyer Industries and Mitsubishi Heavy Industries. The objective of the project is to develop a commercially viable all-electric bus design with near-zero emissions for use in urban transit systems.

FortWhyte EcoVillage
The Affordable Energy Fund supported the research and design of a world-class ecovillage on land belonging to FortWhyte Alive.

Diesel Community Green Pilot Demonstration
This initiative provides funding to support a pilot demonstration focusing on green technologies in one of four diesel communities.

Métis Generation Fund for Resource & Energy Development
The Affordable Energy Fund is providing funding to the Métis Generation fund, managed by the Métis Economic Development Organization. This fund was created to enable Metis-owned businesses in Manitoba to invest in business growth and development within the resource and energy sectors in Manitoba.

Furnace Replacement Budget

The Furnace Replacement budget is an internal allocation established as a result of Public Utility Board Order 99/07. The purpose of the allocation is to establish and administer a Furnace Replacement Program for low income customers.

The following table outlines the planned additions and expenditures over the planning horizon.

Furnace Replacement Budget
(Millions $)

		2015/16	2016/17	2017/18	2018/19 - 2029/30	Total
Furance Replacement Budget						
Opening Balance	18.2					
Annual Additions		3.8	-	-	-	22.0
Annual Budget		2.4	2.5	2.6	12.5	20.0
Annual Balance	$18.2	$19.5	$17.0	$14.4	$1.9	$1.9

Note: Figures may not add due to rounding

2.2.3 Additional External Sources

Manitoba Hydro's Power Smart programs are supported by funding from external organizations as outlined in the following table.

The Affordable Energy Program includes partnership funding from the Provincial Government. This external funding is expected to total $2.0 million over the period of 2015/16 to 2029/30.

External Funding Budget
2015/16 - 2029/30
(Millions $)

	2015/16	2016/17	2017/18	2018/19-2029/30	Total
External Funding					
Affordable Energy Program	0.4	0.3	0.2	1.0	2.0
Cumulative Budget, 2015/16 - 2029/30	$0.4	$0.7	$0.9	$2.0	$2.0

Note: Figures may not add due to rounding

2.3 DSM Metrics and other related measurements

2.3.1 Integrated Perspective

Metrics

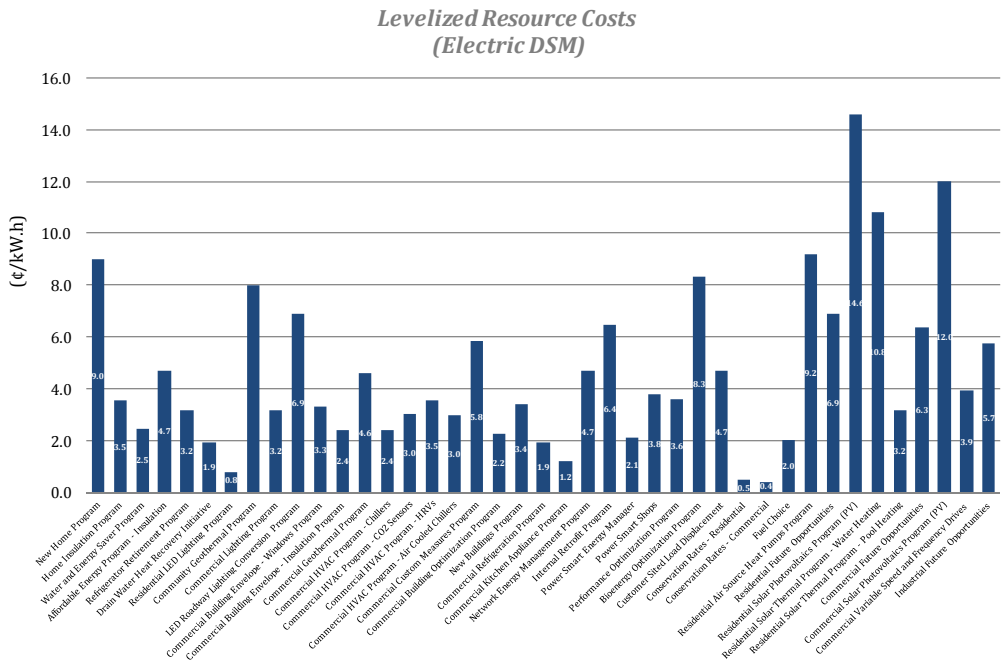
The following table outlines the cost effectiveness, from an integrated perspective, of the program offerings provided in the 2015 Power Smart.

Integrated DSM Metrics
2015/16 - 2029/30

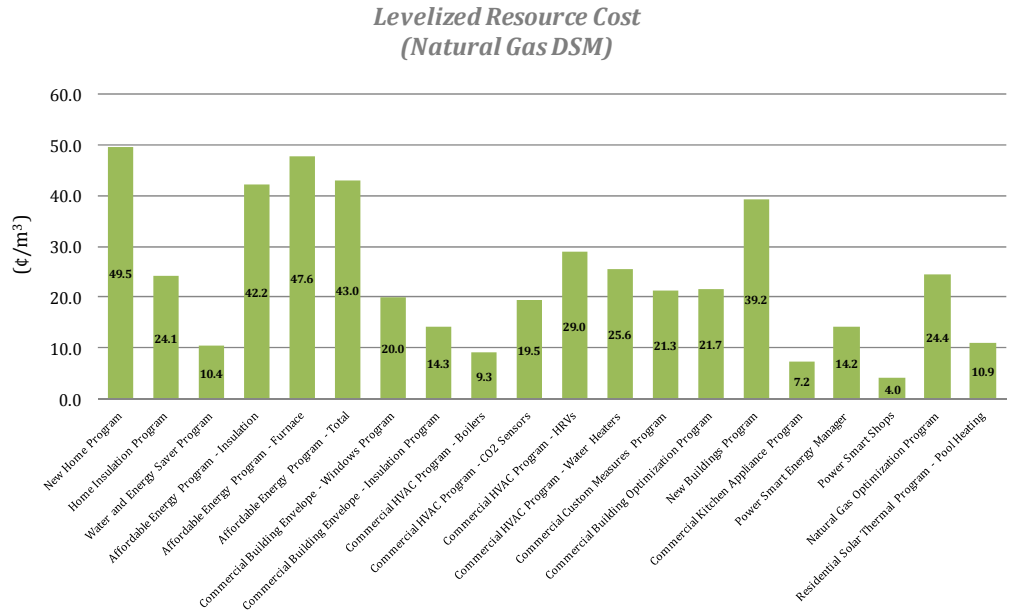
	Combined DSM		Electric DSM				Natural Gas DSM			
	SC	TRC	SC	TRC	TRC NPV	LRC (¢/kW.h)	SC	TRC	TRC NPV	LRC (¢/m³)
Residential										
New Home Program	1.0	0.9	1.6	1.4	$9.6	9.0	0.7	0.6	($12.3)	49.5 *w c*
Home Insulation Program	2.5	2.3	4.2	3.8	$40.9	3.5	1.3	1.2	$3.6	24.1
Water and Energy Saver Program	6.7	6.5	6.4	6.1	$21.6	2.5	7.4	7.2	$11.5	10.4 *w*
Affordable Energy Program										
Affordable Energy Program - Insulation	1.9	1.7	3.1	2.8	$44.0	4.7	0.9	0.8	($6.1)	42.2 *** w*
Affordable Energy Program - Furnace	0.6	0.5	n/a	n/a	n/a	n/a	0.6	0.5	($3.3)	47.6 ****
Affordable Energy Program - Total	1.7	1.6	3.1	2.8	$44.0	4.7	0.8	0.7	($9.5)	43.0 *** w*
Refrigerator Retirement Program	1.9	1.7	2.1	1.9	$15.3	3.2	n/a	n/a	($3.3)	n/a *i*
Drain Water Heat Recovery Initiative	4.2	3.8	4.2	3.8	$1.7	1.9	n/a	n/a	n/a	n/a
Residential LED Lighting Program	11.6	10.5	14.1	12.8	$20.2	0.8	n/a	n/a	($4.0)	n/a *i*
Community Geothermal Program	1.8	1.7	1.8	1.7	$34.6	8.0	n/a	n/a	n/a	n/a
Residential Programs Total	1.9	1.8	2.6	2.4	$188.0	4.9	0.9	0.8	($13.9)	40.6
Commercial										
Commercial Lighting Program	3.1	2.8	3.3	3.0	$262.0	3.2	n/a	n/a	($28.1)	n/a *i*
LED Roadway Lighting Conversion Program	1.5	1.4	1.5	1.4	$18.3	6.9	n/a	n/a	n/a	n/a
Commercial Building Envelope - Windows Program	3.2	2.9	4.5	4.1	$31.6	3.3	1.5	1.4	$3.3	20.0
Commercial Building Envelope - Insulation Program	3.3	3.0	6.2	5.6	$37.5	2.4	2.2	2.0	$18.6	14.3
Commercial Geothermal Program	3.3	3.0	3.3	3.0	$77.1	4.6	n/a	n/a	n/a	n/a
Commercial HVAC Program - Boilers	3.3	3.0	n/a	n/a	n/a	n/a	3.3	3.0	$12.6	9.3 *c*
Commercial HVAC Program - Chillers	1.9	1.7	1.9	1.7	$2.4	2.4	n/a	n/a	n/a	n/a
Commercial HVAC Program - CO2 Sensors	3.0	2.7	5.9	5.4	$4.6	3.0	1.6	1.4	$0.8	19.5
Commercial HVAC Program - HRVs	2.3	2.1	4.6	4.2	$12.1	3.5	1.1	1.0	$0.1	29.0
Commercial HVAC Program - Air Cooled Chillers	1.4	1.3	1.4	1.3	$1.3	3.0	n/a	n/a	n/a	n/a
Commercial HVAC Program - Water Heaters	1.2	1.1	n/a	n/a	n/a	n/a	1.2	1.1	$0.2	25.6
Commercial Custom Measures Program	1.7	1.5	1.8	1.6	$10.4	5.8	1.5	1.3	$1.4	21.3
Commercial Building Optimization Program	2.3	2.1	4.3	3.9	$9.4	2.2	1.4	1.3	$1.9	21.7
New Buildings Program	3.3	3.0	4.1	3.7	$323.7	3.4	0.9	0.8	($8.3)	39.2 *c*
Commercial Refrigeration Program	4.7	4.2	4.1	3.7	$40.2	1.9	n/a	n/a	$8.2	n/a *i*
Commercial Kitchen Appliance Program	14.9	14.5	16.9	16.2	$4.5	1.2	14.1	13.7	$8.5	7.2 *w*
Network Energy Management Program	1.6	1.4	1.6	1.5	$1.3	4.7	n/a	n/a	($0.2)	n/a *i*
Internal Retrofit Program	1.2	1.1	1.2	1.1	$0.7	6.4	n/a	n/a	n/a	n/a
Power Smart Energy Manager	3.3	3.0	4.2	3.8	$2.8	2.1	2.0	1.9	$0.6	14.2
Power Smart Shops	3.7	3.4	3.3	3.0	$3.9	3.8	28.8	28.2	$0.8	4.0 *w*
Commercial Programs Total	3.0	2.7	3.3	3.0	$844.0	3.5	1.3	1.2	$19.9	25.3
Industrial										
Performance Optimization Program	2.4	2.2	2.4	2.2	$161.4	3.6	n/a	n/a	n/a	n/a
Natural Gas Optimization Program	1.2	1.1	n/a	n/a	n/a	n/a	1.2	1.1	$1.8	24.4
Industrial Programs Total	2.2	2.0	2.4	2.2	$161.4	3.6	1.2	1.1	$1.8	24.4
Energy Efficiency Subtotal	2.6	2.3	3.0	2.7	$1,193.4	3.7	1.1	1.0	$7.7	30.1
Load Management										
Curtailable Rate Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Load Management Programs Total	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Load Displacement & Alternative Energy										
Bioenergy Optimization Program	1.7	1.6	1.7	1.6	$83.8	8.3	n/a	n/a	n/a	n/a
Customer Sited Load Displacement	1.7	1.5	1.7	1.5	$196.6	4.7	n/a	n/a	n/a	n/a
Load Displacement & Alt. Energy Programs Total	1.7	1.5	1.7	1.5	$280.4	5.3	n/a	n/a	n/a	n/a
Conservation Rates										
Conservation Rates - Residential	17.2	15.7	17.2	15.7	$138.5	0.5	n/a	n/a	n/a	n/a
Conservation Rates - Commercial	21.7	19.7	21.7	19.7	$219.5	0.4	n/a	n/a	n/a	n/a
Conservation Rates Total	19.7	17.9	19.7	17.9	$358.0	0.4	n/a	n/a	n/a	n/a
Fuel Choice										
Fuel Choice	7.3	6.6	7.3	6.6	$416.2	2.0	n/a	n/a	n/a	n/a
Fuel Choice Total	7.3	6.6	7.3	6.6	$416.2	2.0	n/a	n/a	n/a	n/a
Other Emerging Technologies										
Residential Air Source Heat Pumps Program	0.8	0.7	0.8	0.7	($1.3)	9.2	n/a	n/a	n/a	n/a
Residential Future Opportunities	1.5	1.3	1.5	1.3	$17.4	6.9	n/a	n/a	n/a	n/a
Residential Solar Photovoltaics Program (PV)	0.6	0.5	0.6	0.5	($38.8)	14.6	n/a	n/a	n/a	n/a
Residential Solar Thermal Program - Water Heating	0.7	0.6	0.7	0.6	($1.1)	10.8	n/a	n/a	n/a	n/a
Residential Solar Thermal Program - Pool Heating	2.4	2.2	1.3	1.1	$0.1	3.2	2.9	2.7	$1.8	10.9
Commercial Future Opportunities	1.6	1.5	1.6	1.5	$21.3	6.3	n/a	n/a	n/a	n/a
Commercial Solar Photovoltaics Program (PV)	0.7	0.7	0.7	0.7	($34.0)	12.0	n/a	n/a	n/a	n/a
Commercial Variable Speed and Frequency Drives	1.5	1.4	1.5	1.4	$0.8	3.9	n/a	n/a	n/a	n/a
Industrial Future Opportunities	1.8	1.7	1.8	1.7	$28.3	5.7	n/a	n/a	n/a	n/a
Other Emerging Technologies Total	1.1	1.0	1.1	1.0	($7.4)	8.9	2.9	2.7	$1.8	10.9
Program Impacts Total	2.4	2.2	2.6	2.4	$2,240.7	4.0	1.1	1.0	$9.6	29.8
Program Support and Contingency Costs	-	-	-	-	$0.0	-	-	-	$0.0	-
Program Impacts Total (Incl. Support and Contingency Costs)	2.4	2.1	2.5	2.3	$2,194.8	4.1	1.1	1.0	($0.8)	31.3
Other Internal DSM Investments										
Affordable Energy Fund	-	-	-	-	($1.1)	-	-	-	($0.6)	-
Overall Portfolio Metric	2.4	2.1	2.5	2.3	$2,193.7	4.2	1.1	1.0	($1.4)	31.4

Notes:
*** Includes all Affordable Energy Fund Expenditures and Furnace Replacement Program*
AEP Electric - Total:
Excluding AEF & External costs, SC is 3.1, TRC is 2.9, TRC NPV is $44.2M, and LRC is 4.7 ¢/kW.h
AEP Natural Gas - Total:
Excluding AEF & External costs, w/o Furnace Replacement Program, SC is 0.9, TRC is 0.8, TRC NPV is -$6.2M, and LRC is 42.1 ¢/kW.h
c Program assumption includes savings from Codes & Standards
i Program reflects natural gas interactive effects
w SC, TRC and TRC NPV include Water Savings Benefits
1) Overall portfolio metrics do not include Customer Service Initiatives / Financial Loan Programs nor Curtailable Rate Program
2) Overall portfolio metrics include all support, contingency and Affordable Energy Fund Expenditures and Furance Replacement Program

The following chart provides the Levelized Resource Cost of the electric program offerings in the 2015 Power Smart Plan.



The following chart provides the Levelized Resource Cost of the natural gas program offerings in the 2015 Power Smart Plan.

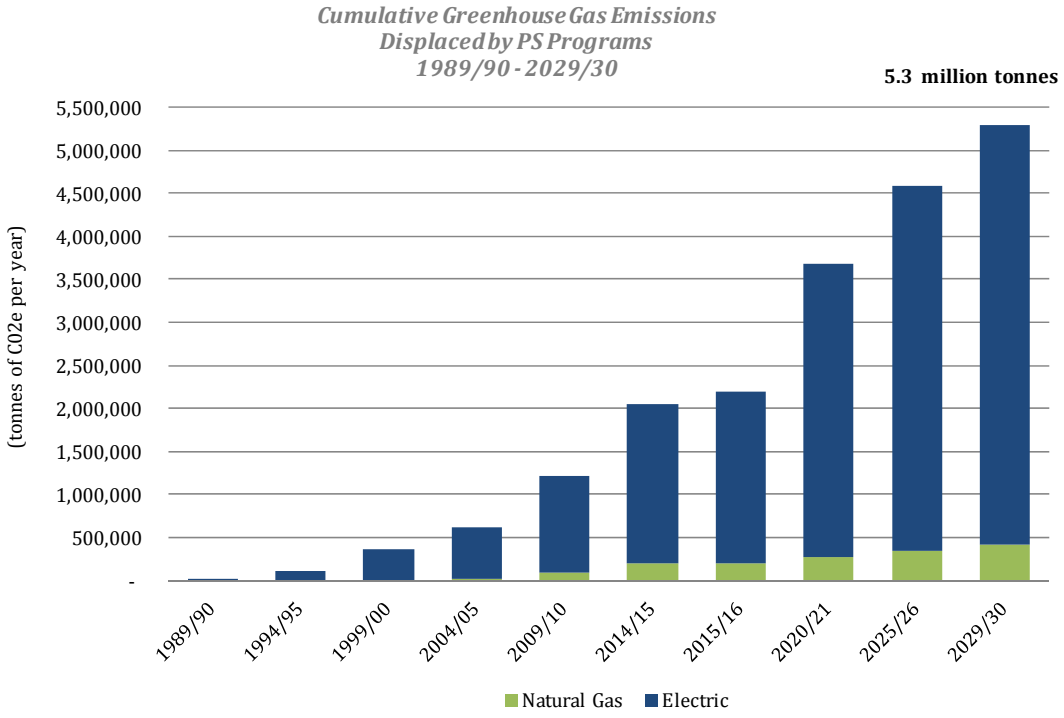


Global Greenhouse Gas Emissions Reductions

The following chart and graph depict the aggregate global greenhouse gas emissions reductions resulting from the electricity and natural gas DSM programs outlined in the 2015 Power Smart Plan, including greenhouse gas emission reductions resulting from Manitoba Hydro's Power Smart efforts since 1989. Global greenhouse gas emission reductions of 3.3 million tonnes are forecast to be achieved due to energy savings outlined in the Power Smart Plan.

	Annual CO_2 Reductions (tonnes)
CO_2 Reductions - Electric	3,118,131
CO_2 Reductions - Natural Gas	224,867
2015/16 Power Smart Plan (2015/16 - 2029/30)	3,342,998
CO_2 Reductions Achieved to Date - Electric	1,764,312
CO_2 Reductions Achieved To Date - Natural Gas	192,468
Savings Achieved to 2014/15 (1989/90 - 2029/30)	1,956,780
Total Projected to 2029/30	5,299,778

Including reductions achieved to date, approximately 5.3 million tonnes are forecast to be realized due to Manitoba Hydro's Power Smart efforts by 2029/30.

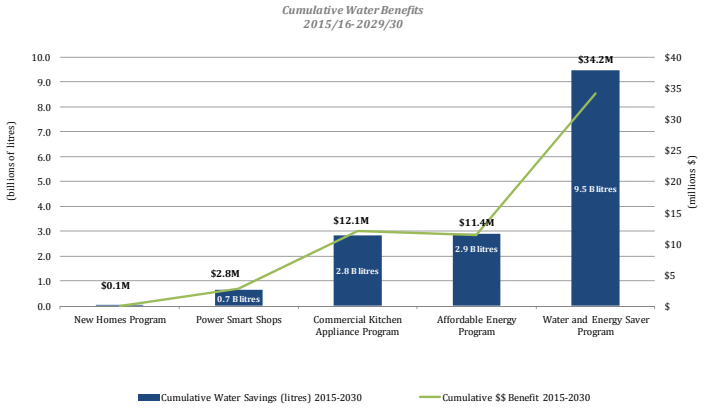


Additional Measureable Non-Energy Benefits

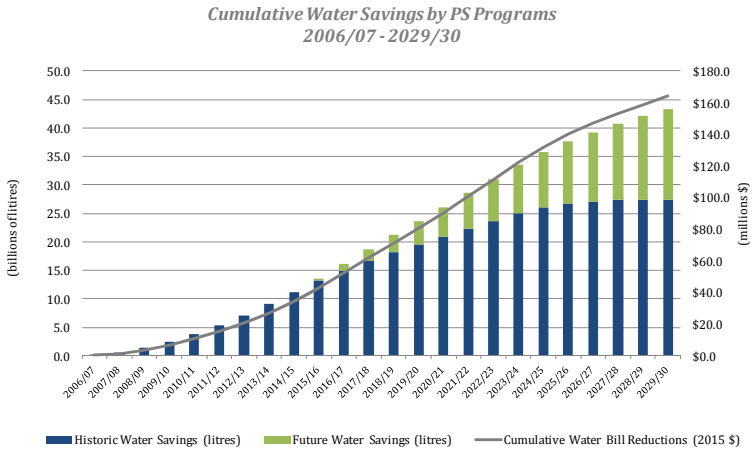
As part of the 2015 Power Smart Plan, the following residential and commercial programs are expected to capture additional water saving benefits:

- Water and Energy Saver Program
- Affordable Energy Program
- Commercial Kitchen Appliance Program
- Power Smart Shops

The following graph depicts cumulative water savings in litres and cumulative customer dollar savings from each of the above programs. It is estimated that savings of approximately 16 billion liters of water and $61 million in bill savings will be achieved from 2015/16 to 2029/30.



When combined with savings to date, Power Smart programs are expected to save approximately 43 billion liters of water and $164 million by 2029/30.



2.3.2 Utility Perspective

Metrics

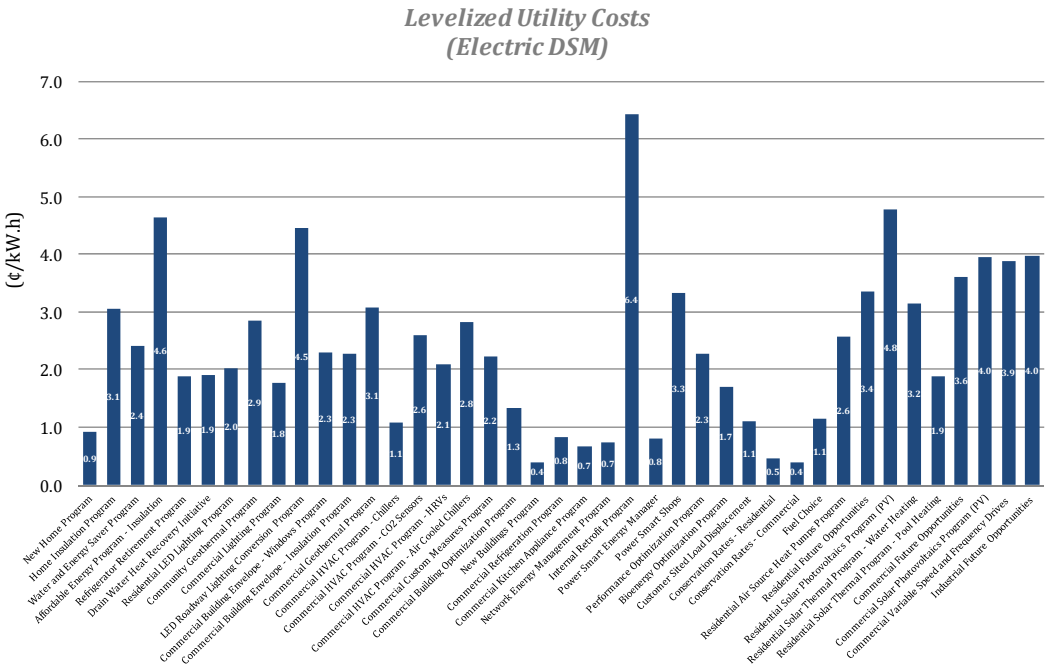
The following table outlines the cost effectiveness, from a utility perspective, of the program offerings provided in the 2015 Power Smart Plan.

Utility DSM Metrics
2015/16 - 2029/30

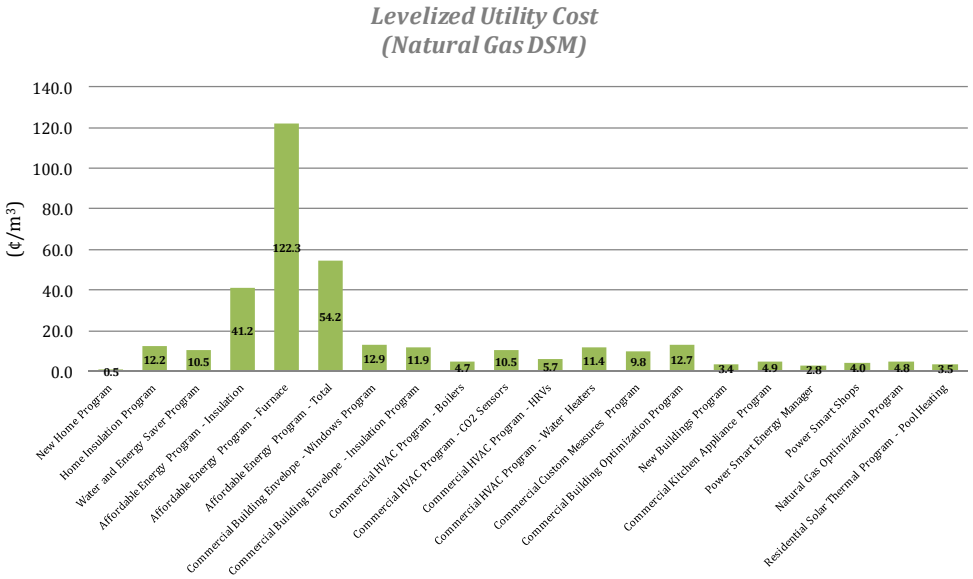
	Electric DSM				Natural Gas DSM				
	RIM	NUB	NPV	LUC (¢/kW.h)	RIM	NUB	NPV	LUC ($¢/m^3$)	
Residential									
New Home Program	1.3	4.1	$6.7	0.9	0.8	-12.7	($4.6)	0.5	*c*
Home Insulation Program	1.1	1.5	$6.1	3.1	0.6	-0.6	($16.7)	12.2	
Water and Energy Saver Program	0.8	-0.1	($4.4)	2.4	0.6	-0.7	($3.2)	10.5	
Affordable Energy Program									
Affordable Energy Program - Insulation	0.9	0.6	($9.0)	4.6	0.3	-0.2	($35.5)	41.2	**
Affordable Energy Program - Furnace	n/a	n/a	n/a	n/a	0.1	-0.1	($18.2)	122.3	**
Affordable Energy Program - Total	0.9	0.6	($9.0)	4.6	0.3	-0.1	($53.7)	54.2	**
Refrigerator Retirement Program	0.6	-0.8	($17.5)	1.9	n/a	n/a	$1.1	n/a	*i*
Drain Water Heat Recovery Initiative	0.7	-0.6	($1.0)	1.9	n/a	n/a	n/a	n/a	
Residential LED Lighting Program	1.0	1.0	($0.2)	2.0	n/a	n/a	$1.2	n/a	*i*
Community Geothermal Program	1.1	1.6	$10.7	2.9	n/a	n/a	n/a	n/a	
Residential Programs Total	1.0	0.9	($8.7)	2.8	0.4	-0.3	($75.9)	26.8	
Commercial									
Commercial Lighting Program	1.0	1.0	($1.7)	1.8	n/a	n/a	$5.6	n/a	*i*
LED Roadway Lighting Conversion Program	0.7	0.6	($19.6)	4.5	n/a	n/a	n/a	n/a	
Commercial Building Envelope - Windows Program	1.3	2.2	$8.8	2.3	0.6	-0.3	($6.9)	12.9	
Commercial Building Envelope - Insulation Program	1.2	2.0	$7.7	2.3	0.6	-0.3	($21.4)	11.9	
Commercial Geothermal Program	1.2	1.7	$18.6	3.1	n/a	n/a	n/a	n/a	
Commercial HVAC Program - Boilers	n/a	n/a	n/a	n/a	0.8	-0.7	($5.5)	4.7	*c*
Commercial HVAC Program - Chillers	0.6	-1.2	($3.3)	1.1	n/a	n/a	n/a	n/a	
Commercial HVAC Program - CO2 Sensors	1.2	2.2	$1.1	2.6	0.7	-0.3	($1.4)	10.5	
Commercial HVAC Program - HRVs	1.2	2.3	$3.0	2.1	0.8	-0.5	($2.3)	5.7	
Commercial HVAC Program - Air Cooled Chillers	0.5	-0.4	($6.2)	2.8	n/a	n/a	n/a	n/a	
Commercial HVAC Program - Water Heaters	n/a	n/a	n/a	n/a	0.6	-0.3	($1.5)	11.4	
Commercial Custom Measures Program	1.0	0.8	($1.2)	2.2	0.7	-0.3	($2.5)	9.8	
Commercial Building Optimization Program	1.0	1.0	$0.1	1.3	0.6	-0.3	($5.3)	12.7	
New Buildings Program	1.3	7.6	$90.3	0.4	0.8	-0.8	($5.8)	3.4	*c*
Commercial Refrigeration Program	1.0	0.7	($1.8)	0.8	n/a	n/a	($1.3)	n/a	*i*
Commercial Kitchen Appliance Program	1.0	1.3	$0.1	0.7	0.7	-1.1	($0.9)	4.9	
Network Energy Management Program	1.0	1.1	$0.1	0.7	n/a	n/a	$0.0	n/a	*i*
Internal Retrofit Program	1.1	1.1	$0.7	6.4	n/a	n/a	n/a	n/a	
Power Smart Energy Manager	1.2	2.8	$0.7	0.8	0.8	-1.0	($0.3)	2.8	
Power Smart Shops	0.8	0.4	($1.0)	3.3	0.7	-1.9	($0.1)	4.0	
Commercial Programs Total	1.1	1.5	$96.1	1.6	0.7	-0.3	($49.7)	10.0	
Industrial									
Performance Optimization Program	0.9	0.8	($15.8)	2.3	n/a	n/a	n/a	n/a	
Natural Gas Optimization Program	n/a	n/a	n/a	n/a	0.8	-0.5	($6.2)	4.8	
Industrial Programs Total	0.9	0.8	($15.8)	2.3	0.8	-0.5	($6.2)	4.8	
Energy Efficiency Subtotal	1.0	1.2	$71.6	1.9	0.6	-0.3	($131.7)	14.8	
Load Management									
Curtailable Rate Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
Load Management Programs Total	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	
Load Displacement & Alternative Energy									
Bioenergy Optimization Program	1.4	3.1	$63.2	1.7	n/a	n/a	n/a	n/a	
Customer Sited Load Displacement	1.1	1.5	$43.6	1.1	n/a	n/a	n/a	n/a	
Load Displacement & Alt. Energy Programs Total	1.2	1.9	$106.8	1.2	n/a	n/a	n/a	n/a	
Conservation Rates									
Conservation Rates - Residential	0.8	-3.8	($45.5)	0.5	n/a	n/a	n/a	n/a	
Conservation Rates - Commercial	1.1	3.0	$23.0	0.4	n/a	n/a	n/a	n/a	
Conservation Rates Total	0.9	-0.1	($22.5)	0.4	n/a	n/a	n/a	n/a	
Fuel Choice									
Fuel Choice	1.3	3.9	$123.2	1.1	n/a	n/a	n/a	n/a	
Fuel Choice Total	1.3	3.9	$123.2	1.1	n/a	n/a	n/a	n/a	
Other Emerging Technologies									
Residential Air Source Heat Pumps Program	0.5	-1.2	($2.7)	2.6	n/a	n/a	n/a	n/a	
Residential Future Opportunities	0.7	-0.1	($27.1)	3.4	n/a	n/a	n/a	n/a	
Residential Solar Photovoltaics Program (PV)	0.5	-0.4	($39.3)	4.8	n/a	n/a	n/a	n/a	
Residential Solar Thermal Program - Water Heating	0.5	-0.9	($1.6)	3.2	n/a	n/a	n/a	n/a	
Residential Solar Thermal Program - Pool Heating	0.3	-3.0	($1.1)	1.9	0.7	-1.9	($1.1)	3.5	
Commercial Future Opportunities	0.8	0.4	($16.8)	3.6	n/a	n/a	n/a	n/a	
Commercial Solar Photovoltaics Program (PV)	0.7	0.0	($35.0)	4.0	n/a	n/a	n/a	n/a	
Commercial Variable Speed and Frequency Drives	0.7	0.3	($1.5)	3.9	n/a	n/a	n/a	n/a	
Industrial Future Opportunities	0.9	0.6	($11.4)	4.0	n/a	n/a	n/a	n/a	
Other Emerging Technologies Total	0.7	0.1	($136.5)	3.9	0.7	-1.9	($1.1)	3.5	
Program Impacts Total	1.0	1.2	$142.5	1.7	0.6	-0.3	($132.8)	14.6	
Program Support and Contingency Costs	-	-	$0.0	-	-	-	$0.0	-	
Program Impacts Total (Incl. Support and Contingency Costs)	1.0	1.1	$96.7	1.8	0.6	-0.3	($143.2)	16.1	
Other Internal DSM Investments									
Affordable Energy Fund	-	-	$0.0	-	-	-	($0.6)	-	
Overall Portfolio Metric	1.0	1.1	$95.6	1.8	0.6	-0.3	($143.8)	16.2	10.8

Notes:
*** Includes all Affordable Energy Fund Expenditures and Furnace Replacement Program*
AEP Electric - Total:
Excluding AEF costs, RIM is 0.9, NUB is 0.66, NPV is -$7.6M, and LUC is 4.4 ¢/kW.h
AEP Natural Gas - Total:
Excluding AEF costs, without Furnance Replacement Program, RIM is 0.4, NUB is -0.2, NPV is -$32.9M, and LUC is 37.6 ¢/m3
c Program assumption includes savings from Codes & Standards
i Program reflects natural gas interactive effects
1) Overall portfolio metrics do not include Customer Service Initiatives / Financial Loan Programs nor Curtailable Rate Program
2) Overall portfolio metrics include all support, contingency and Affordable Energy Fund Expenditures and Furance Replacement Program
3) Excluding the Affordable Energy Program, overall natural gas LUC is 10.8 ¢/m3

The following chart provides the Levelized Utility Cost of the electric program offerings in the 2015 Power Smart Plan.



The following chart provides the Levelized Utility Cost of the natural gas program offerings in the 2015 Power Smart Plan.



2.3.3 Customer Perspective

Metrics

The following table outlines the cost effectiveness, from a participating customer perspective, of the program offerings provided in the 2015 Power Smart Plan.

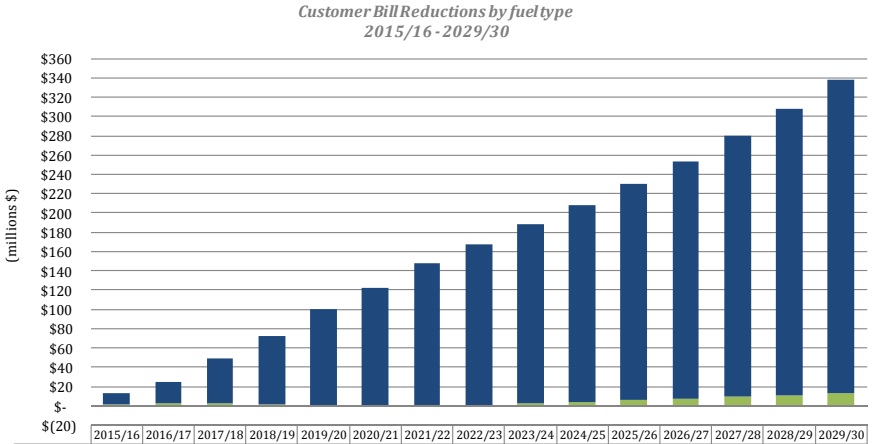
Customer DSM Metrics
2015/16 - 2029/30

	Electric			Natural Gas DSM		
	Payback	PC	PC NPV	Payback	PC	PC NPV
Residential						
New Home Program	19.4	1.1	$2.9	21.7	0.7	($9.9) *w*
Home Insulation Program	1.1	5.4	$34.8	6.0	2.0	$17.8
Water and Energy Saver Program	0.1	28.2	$26.0	0.0	21.3	$14.5 *w*
Affordable Energy Program						
Affordable Energy Program - Insulation	n/a	n/a	n/a	n/a	n/a	n/a
Affordable Energy Program - Furnace	n/a	n/a	n/a	n/a	n/a	n/a
Affordable Energy Program - Total	n/a	n/a	n/a	n/a	n/a	n/a
Refrigerator Retirement Program	1.6	4.7	$32.9	n/a	n/a	($4.3) *i*
Drain Water Heat Recovery Initiative	0.0	5.9	$2.7	n/a	n/a	n/a
Residential LED Lighting Program	0.0	0.0	$20.4	n/a	n/a	($4.9) *i*
Community Geothermal Program	9.9	1.5	$23.9	n/a	n/a	n/a
Commercial						
Commercial Lighting Program	3.3	3.5	$263.7	n/a	n/a	($30.9) *i*
LED Roadway Lighting Conversion Program	0.0	1.6	$27.1	n/a	n/a	n/a
Commercial Building Envelope - Windows Program	1.5	4.3	$22.8	1.2	2.2	$9.0
Commercial Building Envelope - Insulation Program	0.3	7.7	$29.8	1.4	2.9	$36.0
Commercial Geothermal Program	5.4	2.7	$58.5	n/a	n/a	n/a
Commercial HVAC Program - Boilers	n/a	n/a	n/a	2.4	4.0	$16.4
Commercial HVAC Program - Chillers	2.8	3.0	$5.7	n/a	n/a	n/a
Commercial HVAC Program - CO2 Sensors	0.6	7.9	$3.6	3.0	2.3	$2.0
Commercial HVAC Program - HRVs	4.5	3.8	$9.2	13.7	1.2	$1.5
Commercial HVAC Program - Air Cooled Chillers	2.3	2.8	$7.6	n/a	n/a	n/a
Commercial HVAC Program - Water Heaters	n/a	n/a	n/a	5.1	1.7	$1.4
Commercial Custom Measures Program	9.3	1.7	$11.6	6.5	2.0	$3.4
Commercial Building Optimization Program	1.8	4.9	$9.3	3.5	2.3	$6.4
New Buildings Program	8.3	3.0	$233.4	25.7	0.8	($6.7)
Commercial Refrigeration Program	0.3	4.3	$42.0	n/a	n/a	$8.7 *i*
Commercial Kitchen Appliance Program	0.2	18.2	$4.5	0.2	19.7	$9.2 *w*
Network Energy Management Program	2.4	1.5	$1.3	n/a	n/a	($0.2) *i*
Internal Retrofit Program	0.0	1.0	$0.0	n/a	n/a	n/a
Power Smart Energy Manager	0.0	4.4	$2.1	0.0	2.4	$0.7
Power Smart Shops	0.5	5.2	$5.0	0.0	30.7	$0.9 *w*
Industrial						
Performance Optimization Program	3.3	2.8	$177.2	n/a	n/a	n/a
Natural Gas Optimization Program	n/a	n/a	n/a	9.0	1.3	$6.1
Load Management						
Curtailable Rate Program	n/a	n/a	$0.0	n/a	n/a	n/a
Load Displacement & Alternative Energy						
Bioenergy Optimization Program	3.1	1.1	$20.6	n/a	n/a	n/a
Customer Sited Load Displacement	4.1	1.4	$153.0	n/a	n/a	n/a
Conservation Rates						
Conservation Rates - Residential	n/a	n/a	$184.0	n/a	n/a	n/a
Conservation Rates - Commercial	n/a	n/a	$196.5	n/a	n/a	n/a
Fuel Choice						
Fuel Choice	1.9	5.1	$293.0	n/a	n/a	n/a
Other Emerging Technologies						
Residential Air Source Heat Pumps Program	9.3	1.4	$1.4	n/a	n/a	n/a
Residential Future Opportunities	6.5	2.1	$44.4	n/a	n/a	n/a
Residential Solar Photovoltaics Program (PV)	12.8	1.0	$0.5	n/a	n/a	n/a
Residential Solar Thermal Program - Water Heating	14.9	1.2	$0.5	n/a	n/a	n/a
Residential Solar Thermal Program - Pool Heating	2.1	6.1	$1.2	2.7	3.8	$2.6
Commercial Future Opportunities	6.0	1.9	$38.1	n/a	n/a	n/a
Commercial Solar Photovoltaics Program (PV)	12.0	1.0	$1.1	n/a	n/a	n/a
Commercial Variable Speed and Frequency Drives	2.4	3.9	$2.3	n/a	n/a	n/a
Industrial Future Opportunities	4.3	2.2	$39.6	n/a	n/a	n/a
Other Emerging Technologies Total						
Overall Portfolio Metric	n/a	2.4	$2,087.3	n/a	1.6	$121.4

Notes:
i Program reflects natural gas interactive effects
w Payback, PC and PC NPV include Water Savings Benefits

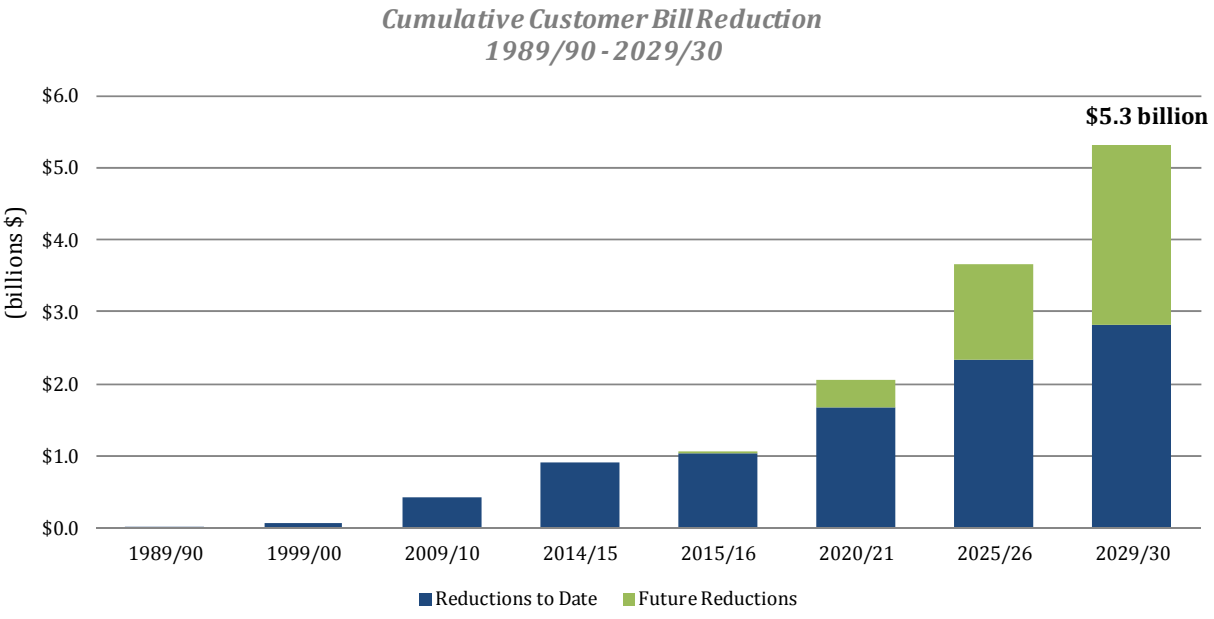
Combined Customer Bill Reductions

The following graph depicts customer bill reductions resulting from electric and natural gas programs outlined in the 2015 Power Smart Plan. Power Smart programs are expected to save participating customers an additional $13 million in 2015/16 alone, $338 million in 2029/30 and $2.5 billion cumulatively by 2029/30.



	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30
Electric	$11	$22	$46	$70	$99	$123	$148	$167	$185	$205	$224	$246	$270	$297	$326
Natural Gas	$1	$3	$3	$2	$1	$0	$(1)	$1	$2	$4	$6	$8	$10	$11	$13
Annual	$13	$25	$49	$72	$100	$123	$148	$167	$188	$208	$230	$254	$280	$308	$338
Cumulative	$13	$38	$87	$159	$259	$382	$529	$696	$884	$1,093	$1,323	$1,577	$1,856	$2,164	$2,503

When combined with bill reductions to date, Power Smart programs are expected to save participating customers $ 455 million in 2029/30 and over $ 5.3 billion cumulatively by 2029/30.



2015 Power Smart Plan | Supplemental Report 15 yr (2015 to 2030)

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Working Document

2012/13 Power Smart Plan

Power Smart Planning, Evaluation &
Research Department

Customer Care & Energy Conservation Business Unit

Manitoba Hydro
POWER SMART

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EXECUTIVE SUMMARY

Manitoba Hydro's 2012/13 Power Smart Plan provides a roadmap for the future direction of the Corporation's energy conservation program. The Plan was developed through an intensive planning process which builds on the Corporation's experience and continuous involvement in energy management since 1989. The planning process involved research on energy management technologies and practices, research on activities of other leading-edge organizations delivering energy efficiency programs and the development of program design concepts.

The 2012/13 Power Smart Plan is a 15-year plan that forecasts Manitoba Hydro's energy savings and investments to the benchmark year of 2026/27 which will be achieved through electricity and natural gas Power Smart Programs. The plan sets out to realize electricity savings of 511 MW and 1,624 GW.h, natural gas savings of 72 million cubic meters and combined global greenhouse gas emission reductions of 1.2 million tonnes by 2026/27. These savings represent 2.7 percent of the estimated electric load forecast and 2.9 percent of the natural gas load forecast for 2026/27. The total cost of achieving the energy savings is $452 million; $337 million of the costs are funded through the Corporation's Power Smart electricity budget, $84 million from the Power Smart natural gas budget, $19 million from the Affordable Energy Fund, and $12 million from the Lower Income Natural Gas Furnace Replacement budget for targeting furnace replacement.

Combined with energy savings achieved to date, total electrical savings of 857 MW and 3,150 GW.h and total natural gas savings of 136 million cubic meters will be realized by 2026/27. These combined energy savings are expected to result in an overall reduction of greenhouse gas emissions of 2.4 million tonnes by 2026/27. It is expected that by 2026/27, a cumulative investment of achieving the energy savings will have been $940 million dollars, $733 million of the costs are funded through the Corporation's Power Smart electricity budget, $156 million from the Power Smart natural gas budget, $35 million from the Affordable Energy Fund, and $16 million from the Lower Income Natural Gas Furnace Replacement budget for targeting furnace replacement.

By reducing electricity and natural gas consumption through innovative products, participating customers can expect to save $67 million in 2026/27 and $648 million cumulatively by 2026/27. When combined with bill reductions achieved to date, programs are expected to save participating customers $132 million in 2026/27 and over $2.5 billion cumulatively.

The overall Total Resource Cost (TRC) and Societal Cost (SC) metrics for the electric and natural gas Power Smart portfolio is 2.0 and 2.2, respectively. The electric Power Smart portfolio has an overall TRC of 2.4, Rate RIM of 1.1 and an overall levelized utility cost of 2.4 cents per kilowatt-hour. The natural gas Power Smart portfolio has an overall TRC of 1.1, RIM of 0.6 and an overall levelized utility cost of 17.6 cents per cubic meter.

Executive Summary i

1 The 2012/13 Power Smart Plan 1

1.1 Supporting Corporate Strategic Goals 1

1.2 Portfolio Design, Strategies & Principles 4

1.3 Economic Assumptions 10

1.4 Residential Portfolio 12

1.5 Commercial Portfolio 22

1.6 Earth Energy & Emerging Technologies 34

1.7 Industrial Portfolio 39

1.8 Load Management Portfolio 45

1.9 Load Displacement & Alternative Energy Portfolio 45

2 Electric Demand Side Management 46

2.1 Electric DSM Targets 46

2.2 Electric DSM Utility Investment 49

2.3 Electric DSM Cost Effectiveness 50

3 Natural Gas Demand Side Management 52

3.1 Natural Gas DSM Targets 52

3.2 Natural Gas DSM Utility Investment 55

3.3 Natural Gas DSM Cost Effectiveness 56

4 Combined Demand Side Management 58

4.1 Program Duration and Cumulative Participation 58

4.2 Combined DSM Utility Investment 59

4.3 Combined DSM Cost Effectiveness 60

4.4 Combined Global Greenhouse Gas Emissions Reductions 61

4.5 Combined Customer Bill Reductions 62

4.6 Combined Additional Non-Energy Benefits 63

5 Energy Efficient Codes & Standards 64

5.1 Energy savings from Codes & Standards 64

5.2 Status of Codes and Standards 66

5.3 Code, Standard & Regulation Descriptions 67

6 Other Internal Demand Side Management Funding 80

6.1 Affordable Energy Fund 80

6.2 Lower Income Natural Gas Furnace Replacement 85

7 Total Internal Demand Side Management Budget 86

8 Other External Demand Side Management Funding 87

APPENDIX A - 2012/13 Power Smart Plan Electric
Appendix A.1 - Annual Capacity Savings (MW)
Appendix A.2 - Annual Energy Savings (GW.h)
Appendix A.3 - Annual Utility Costs
Appendix A.4 - Annual Program Administration Costs
Appendix A.5 - Annual Program Incentive Costs

APPENDIX B - Historical Electric Savings & Costs
Appendix B.1 - Annual Capacity Savings (MW)
Appendix B.2 - Annual Energy Savings (GW.h)
Appendix B.3 - Annual Utility Costs
Appendix B.4 - Annual Program Administration Costs
Appendix B.5 - Annual Program Incentive Costs

APPENDIX C - 2012/13 Power Smart Plan Natural Gas
Appendix C.1 - Annual Energy Savings (million m3)
Appendix C.2 - Annual Utility Costs
Appendix C.3 - Annual Program Administration Costs
Appendix C.4 - Annual Program Incentive Costs

APPENDIX D - Historical Natural Gas Savings & Costs
Appendix D.1 - Annual Energy Savings (million m3)
Appendix D.2 - Annual Utility Costs
Appendix D.3 - Annual Program Administration Costs
Appendix D.4 - Annual Program Incentive Costs

APPENDIX E - Program Evaluation Criteria
Nature of Electricity and Natural Gas Markets
Program Categories
Economic Effectiveness Metrics
Other DSM Program Assumptions

1 THE 2012/13 POWER SMART PLAN

Manitoba Hydro's 2012/13 Power Smart Plan provides a roadmap for the future direction of the Corporation's energy conservation program. The Plan was developed through an intensive planning process which builds on the Corporation's experience and continuous involvement in energy management since 1989. The planning process involved research on energy management technologies and practices, research on activities of other leading-edge organizations delivering energy efficiency programs and the development of program design concepts.

1.1 SUPPORTING CORPORATE STRATEGIC GOALS

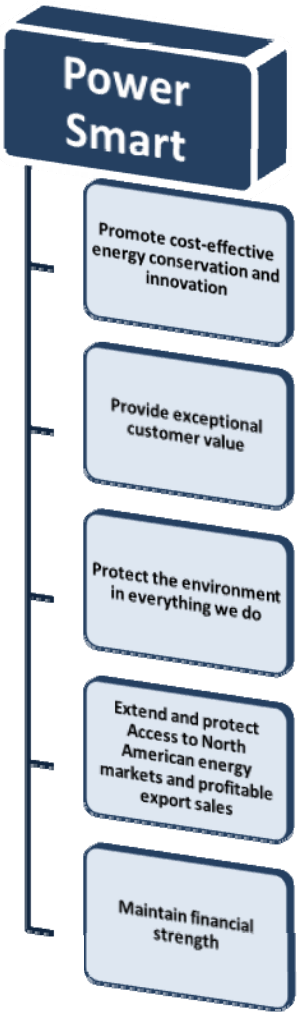
Power Smart is an overall strategy that serves to support Manitoba Hydro's Corporate Strategic Goals.

Through the aggressive development, implementation and promotion of cost-effective energy conservation programs, Power Smart ultimately supports the following strategic goal:

- **Promote cost effective energy conservation and innovation.**

Through its on-going efforts, Power Smart activities concurrently support the following other corporate strategic goals:

- **Provide exceptional customer value**
- **Protect the environment in everything we do**
- **Extend and protect Access to North American energy markets and profitable export sales**
- **Maintain financial strength**



PROMOTE COST-EFFECTIVE ENERGY CONSERVATION AND INNOVATION

Manitoba Hydro's Power Smart activities are designed to aggressively pursue cost-effective energy conservation and explore emerging energy systems to ensure Manitobans are provided with cost-effective alternative methods of energy supply. The strategic goal involves being an industry leader as measured by:

- Manitoba Hydro's long-standing DSM commitments and energy conservation achievements;
- Manitoba Hydro's DSM efforts being comparable to leading edge North American utilities and agencies; and
- Manitoba Hydro's programs exhibiting best practices for energy efficient program designs in today's markets.

Through its on-going efforts, Power Smart activities concurrently support the following other corporate strategic goals:

PROVIDE EXCEPTIONAL CUSTOMER VALUE

Manitoba Hydro's Power Smart activities provide value-added customer service by providing Manitobans with access to energy-saving programs and financial support, expert advice and up-to-date energy-efficiency information. As a result of these on-going efforts, Manitobans realize a number of benefits including:

- Improvement to the comfort and productivity of home and work environments through increased awareness and adoption of energy efficiency measures;
- Energy bill reduction as a result of reduced consumption;
- Assisting businesses in becoming more competitive in national and international markets via economic and qualitative assistance;
- Economic growth by way of new employment opportunities for manufacturers, distributors, retailers, trade allies and installers of energy-efficient products and services.

PROTECT THE ENVIRONMENT IN EVERYTHING WE DO

Manitoba Hydro's Power Smart activities demonstrate the Corporation's commitment to be proactive in protecting the environment and to be the leading utility in promoting sustainable energy supply and service. Through Power Smart activities, greenhouse gas emissions are reduced directly through lower natural gas consumption in Manitoba and indirectly through lower electricity consumption. In the latter case, electricity exports, generated from Manitoba Hydro's clean hydraulic sources, displace electricity that would otherwise be generated elsewhere through greenhouse gas-emitting generating sources (e.g. coal or natural gas).

A primary objective of Power Smart is to achieve a sustainable market shift, or market transformation, towards energy efficient technologies and practices. Through Power Smart initiatives, Manitoba Hydro communicates environmental performance and achievements and assists customers in realizing the associated persisting eco-efficiency benefits.

EXTEND AND PROTECT ACCESS TO NORTH AMERICAN ENERGY MARKETS AND PROFITABLE EXPORT SALES AND MAINTAIN FINANCIAL STRENGTH

Manitoba Hydro's Power Smart activities involve supporting the Corporation's export business and concurrently improving the Corporation's financial strength. The electricity savings derived from Power Smart activities are, in turn, available for sale in the export market. The additional revenues realized through this export activity contribute to improving the Corporation's financial strength.

1.2 PORTFOLIO DESIGN, STRATEGIES & PRINCIPLES

DESIGN OVERVIEW

Power Smart programs for all sectors are designed through an in-depth technology and market research process. Energy efficient technologies or practices ("EE measure") are first screened to determine the economic viability to the customer. Inputs into the process include energy savings, demand savings, interactive effects, product life, product cost and persistence rates. The resulting marginal resource cost metric is a guide to this process, however, other factors are also considered in determining whether an EE measure should continue into the program design phase. For example, emerging technologies often do not provide enough benefits to outweigh the costs but the target market may have a higher threshold for longer payback periods. In these instances, a program may be pursued to assist in stimulating market activity which builds the market capability and helps deliver more cost effective savings in the future.

A thorough understanding of the market; both overall characteristics and drivers and detractors to the EE measure; is essential to ensure that the program design is addressing the proper target market and contains the tools and strategies that will address the barriers present. Market detail includes the target customers, current market share of the EE measure, alternatives to the EE measure including those that are considered the most standard practice, incremental costs of the measure including installation, channels through which the EE measure gets to the market and ancillary customer benefits to the EE measure. These details will guide the overall marketing strategy to ensure that a meaningful message reaches the intended target market in order to drive participation in the program. Although the fundamental processes may be similar, the levels or type of customer engagement will differ for each sector. Residential markets are usually pursued through targeted mass market activities. For the commercial/institutional sector, Manitoba Hydro uses a combination of mass market and customer relationship building approaches. The industrial sector is pursued with greater focus on specific customer relationship building, site-specific energy efficiency screening/monitoring and utilizing a site-specific system approach in identifying opportunities for customers' facilities.

The overall life span of a program will vary by EE measure but generally is established by the length of time that is thought to be required to transform the market to that measure. Tools for permanent market transformation are considered with each design and most commonly come in the form of a regulation (most often for retrofit market) or a code (applies only to new construction opportunities). In addition to the active role Power Smart plays with the Provincial departments responsible for energy regulations and building codes (see section 5), Manitoba Hydro also partners with the Federal Government's Office of Energy Efficiency and the Canadian Standards Association to continually improve the energy performance of products. Manitoba Hydro staff also regularly monitors activities of other Provincial and Territorial Regulation and Code Authorities and the United States Department of Energy since regulatory activities in other jurisdictions may increase a timeline for a regulation locally or, alternatively, result in an influx of inefficient products into Manitoba.

Manitoba Hydro continually monitors the market to identify emerging trends and opportunities, such as integrated manufacturing and sustainable communities, which may become viable and cost effective within the planning horizon. Manitoba Hydro continues to support emerging technologies and practices via research and demonstration projects through both provincial and national industry partnerships.

STRATEGIES

Power Smart's goal is to achieve market transformation; to create a sustainable market change where energy-efficient technologies and practices become the market standard. To achieve this goal, Manitoba Hydro's Power Smart activities are guided by the following key strategies:

✓ **Comprehensive & Technology Specific Approach to Program Design**

This strategy involves assessing and pursuing opportunities from both a systems perspective and technology perspective to determine the best fit for the target market. This process examines systems and technologies that function together within the building or process and optimizes the operation for improved performance efficiency. This approach leads to achieving efficiency improvements in a cost-effective manner. The approach is especially effective in new construction and large retrofit applications.

Technology specific opportunities are effective and appropriate for addressing opportunities such as when a customer is considering an isolated retrofit application.

✓ **Integrated Approach to Program Design**

This strategy involves taking an integrated approach to pursuing energy efficiency objectives, with consideration being given to program impacts on electricity use, natural gas use, greenhouse gas emission reductions, water use and waste reduction.

✓ **Collaborative Approach**

This strategy involves taking a collaborative approach in pursuing energy efficiency objectives. This approach involves:

- partnering and integrating programs offered by other organizations committed to energy efficiency such as the Manitoba Government and Natural Resources Canada;

- consulting and collaborating with industry, trade allies, retailers, distributors and associations on program design and delivery;

- partnering with other utilities and organizations on joint interest projects, including R&D initiatives, code and standards changes and other activity; and

- consulting with and seeking input from interested stakeholders on Manitoba Hydro's overall Power Smart initiative.

✓ **Leveraging Non-Energy Related Benefits**

Power Smart leverages non-energy related benefits associated with energy efficiency initiatives by promoting these benefits and thereby increasing participation in these initiatives. Non-energy benefits include improved comfort, lower maintenance costs, increased productivity, reduced water consumption costs, reduced waste disposal costs, improved product quality and better work environments resulting in increased competitiveness for Manitoba businesses.

✓ **Leveraging the Power Smart & Energy Star Brand**

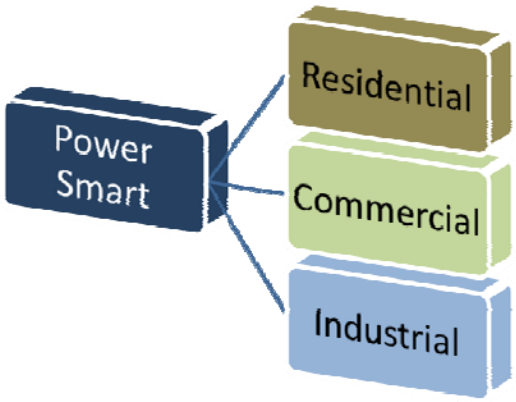
Power Smart recognizes that having an identifiable, trusted and positive brand image adds value to a product or service. The Power Smart Plan includes leveraging the proven strength of the Power Smart brand to increase the effectiveness of the Corporation's conservation efforts. Power Smart is positioned to mean energy efficiency, low energy rates and environmental benefits. Manitoba Hydro also takes strategic advantage of local and national efforts to brand Energy Star; a labeling device identifying products with improved energy efficiency.

POWER SMART FOR BUSINESS
EFFICIENCY PARTNER
Manitoba Hydro POWER SMART

energy ENERGY STAR

✓ **Market Focused**

Power Smart programs and efforts are designed and delivered from a customer perspective. The strategy involves taking a multi-dimensional view where customer attributes and environments are considered from various perspectives, including customer class (e.g. residential, commercial and industrial), customer demographics (e.g. seniors) and customer drivers.



✓ **Leveraging Financial Tools – Loans, Incentives, Rates and Service Fees**

This strategy involves leveraging the financial tools available to Manitoba Hydro for the purpose of achieving energy efficiency objectives in a fair and effective manner.

- **Financing** – this instrument can be effective for addressing the capital or first cost barrier associated with implementing energy efficient measures and can be structured as a cost-recovery financial tool.

- **Incentives** – this instrument can be an effective alternative for addressing the customer's capital or first cost barrier associated with implementing energy efficient measures.

- **Rates –** this instrument can be used to influence a customer's energy management decision by creating a price signal which will directly impact relative operating costs and direct costs to inefficient energy users. Applications include curtailable and inverted rates.

- **Service Fees –** this instrument can be useful in new service applications. Service fees can be designed to create a price signal that will encourage customers to incorporate energy efficiency into the building design.

✓ **Supporting Industry Infrastructure**

This strategy recognizes that a key component of creating a sustainable energy efficient market is establishing a skilled and trained trade ally network and infrastructure. This strategy promotes energy efficiency education in building practices, best practices, and training for targeted groups, including homebuilders, equipment installers, engineers, architects, retailers, distributors and consumers. Sustained success also involves incorporating training into formal educational programs.

✓ **Exit Strategy - Codes and Standards**

Power Smart recognizes the importance of incorporating energy efficiency into codes and standards in creating a sustainable energy efficient future. The strategy involves:

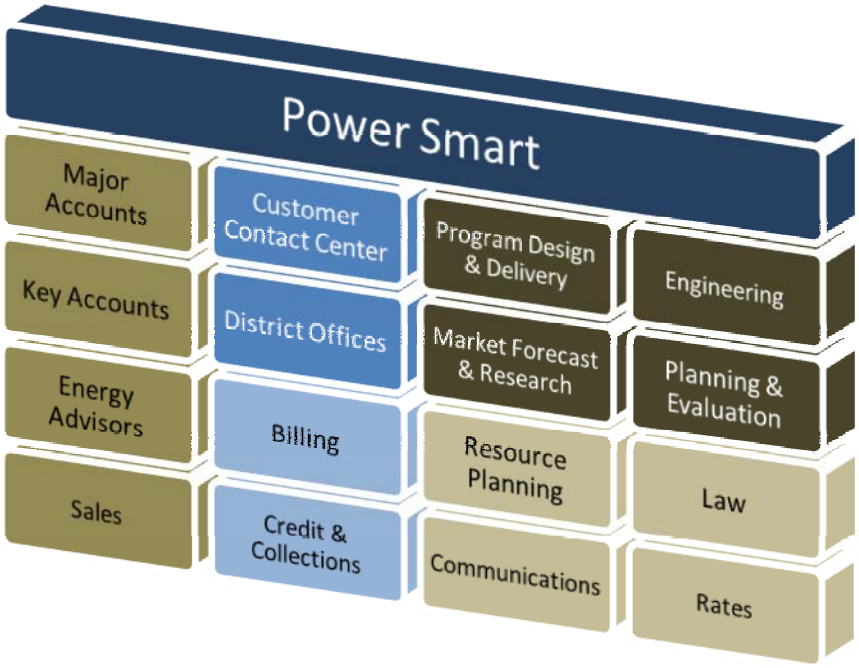
- being an active participant and in many cases, a driving force on a number of provincial and national energy efficiency codes and standards committees; and

- working cooperatively with other utilities, energy efficiency agencies and governments to effectively incorporate energy efficiency into codes and standards.

✓ **Promoting Innovation: Research and Development**

This strategy recognizes that new and innovative solutions to achieving energy efficiencies can be discovered through investment in research and development. This strategy also recognizes that a coordinated approach is more effective and efficient as both financial and technical resources are leveraged.

✓ **Leveraging the Corporation's Extensive Infrastructure and Broad Outreach Capabilities**



This strategy involves leveraging Manitoba Hydro's infrastructure and broad outreach capabilities to achieve greater energy efficiencies in a cost-effective manner:

- **Outreach Efforts** – Energy Service Advisors, Key Account Representatives, Major Account Representatives and District Representatives are located throughout the province. While their regular duties include a variety of customer service activities, a key component is to promote and sell Power Smart programs. These staff members have developed trusted business relationships with their customers, are community leaders and are trained to promote and sell Power Smart programs.

- **Customer Contact Centre** - The Corporation's Customer Contact Centre receives more than 630,000 calls per year, which presents numerous opportunities to promote Power Smart programs and objectives.

- **Technical Support & Delivery Services -** Manitoba Hydro has extensive resources skilled in customer service, marketing, sales, load research, metering, rate design and engineering. These resources are all available to support Power Smart efforts.

- **Borrowing Ability, Billing System, Credit & Collection Processing Capability -** Manitoba Hydro's borrowing ability and billing system offers a convenient means for offering Manitobans financial assistance and repayment options. In addition, access to account information allows for efficient and expedient creditworthiness checks.

- **Demand Response Programs** – As an electric utility, Manitoba Hydro is uniquely positioned to deliver demand response programs.

- **Market Intelligence** – Manitoba Hydro has developed an extensive database on customer end-use profiles and attributes. This database offers value in pursuing a variety of energy efficiency opportunities and targeted marketing efforts.

- **Rates & Services** – Rates offer innovative uses of financial mechanisms for achieving energy efficiency objectives through the use of an inverted rate structures and time of use rates. Similarly, services offer alternative innovative options for pursuing energy efficiency objectives through the use of pre-pay service and differential hook-up structures.

PRINCIPLES

The principles underlying Manitoba Hydro's DSM activity for electricity and natural gas include:

Reducing customer energy bills in a cost-effective and efficient manner
This principle highlights the need to be effective and efficient in designing, delivering and evaluating DSM programs. Inherent in lowering customers bills, DSM programs themselves need to be effective and efficient, otherwise Manitobans will incur unnecessary costs associated with DSM efforts which could undermine one of the underlying principle objectives of DSM programs: reducing customer energy bills.

Minimizing capital spending on infrastructure
This principle highlights the need to integrate utility facility planning with DSM program design. Through a coordinated effort, Manitobans will realize the benefits directly associated with conservation efforts and those indirectly associated with DSM efforts through reduced infrastructure expenditures.

Facilitating an optimal mix of energy supply and demand in Manitoba
This principle highlights the need to undertake integrated resource planning in order to minimize the overall cost of balancing energy supply and demand in Manitoba.

Promoting consistency and fairness
This principle highlights the need to balance the consistency and fairness issue across all customers impacted by DSM efforts. Impacts of DSM programs will be different for participants and non-participants depending on a number of considerations, including the customer's ability to participate. This issue also highlights the need to be considerate of cross-subsidization issues between the natural gas and electricity businesses.

Promoting sustainability and minimizing environmental and social impacts
This goal highlights the need to consider environmental and social impacts. In the first case, programs need to consider environmental impacts either through qualitative or quantitative assessments. In the latter case, consideration needs to be given to social issues such as lower income Manitobans who are unable to participate because of their financial situation.

1.3 ECONOMIC ASSUMPTIONS

Marginal Costs

The Power Smart Plan incorporated the following forecasts to estimate the marginal benefits for energy savings resulting from the revenue realized from conserved electricity being sold in the export market, the avoided costs of new infrastructure and the supply of natural gas:

- Electric – The electric marginal cost forecast was prepared and compiled by the Resource Planning and Market Analysis Department. Marginal values were provided for Distribution Level Programs, General Service Large Programs, Generation Station Internal Retrofit Programs and the Curtailable Rates Program. For the 2012/13 Power Smart Plan, the following assumptions were applied:
    - Marginal costs were based on a uniform supply with a 100% capacity factor
    - Distribution Level Programs used a loss factor of 14% to translate back to generation
    - General Service Large Programs used a loss factor of 10% to translate back to generation
    - Generation Level Programs used a loss factor of 14% to translate back to distribution
    - US/Cdn Exchange Rates and Escalation Factors were derived from the Corporation's G911 corporate policy document issued October 19th, 2011
    - Transmission & distribution marginal costs were updated using SPD 2010/02

- Natural Gas – The marginal cost forecast for natural gas was prepared based on the natural gas rate forecast which was provided by the Economic Analysis Department. Unlike the rate forecast, it does not include distribution costs. The benefits of avoided greenhouse gas emissions were included in the natural gas marginal benefits used to calculate the Total Resource Cost (TRC) metric. A greenhouse gas cost forecast was provided by the Energy Policy & Analysis Department. For the 2012/13 Power Smart Plan, the 2011 GHG forecast values were derived from the GHG price information provided by Export Price Forecast consultants which were consistent with the 2011 values used in the Manitoba Hydro Power Resource Plan, based on the Corporation's G911 corporate policy document issued October 19th, 2011.

In addition, water benefits were calculated based on 2012 City of Winnipeg Water and Sewer rates effective April 1st, 2012.

Customer Rates

The following forecasts were used to determine the impact of customer bill reductions resulting from their Power Smart energy savings:

- Electric – The Electric Rates & Regulatory Department provided the rate forecast for electricity. Commercial and industrial program rates were determined by a weighted average based on the forecasted participation for each of the Corporations' billing classes. Residential rates were consistent for all residential programs. For the 2012/13 Power Smart Plan, the weighted rates were based on the interim-approved April 1st, 2011 rate forecast which assumed the 2012/13 real rates would increase by 1.5% and thereafter by 1.5% per year. This was based on the projected rate increase of 3.5% for 2012/13 and the long term rate increase of 3.5% per year (as

per IFF-10) less the 2012/13 escalation rate of 2.0% and the long term escalation rate of 2.0% (2011 Economic Outlook).

- Natural Gas – The natural gas rate forecast was prepared by the Economic Analysis Department with input from the Energy Price Outlook. For the 2012/13 Power Smart Plan, the following assumptions were applied:
    - Forecast starting point was the February 1st, 2011 rate
    - Commodity price changes into the future were based on the forecast of natural gas prices contained in the Energy Price Outlook which represented a consensus view of futures markets and a suite of five independent forecasting organizations
    - Non-commodity (monthly charge, transportation, distribution) price changes were based on IFF-10 assumptions on general rate increases and the Economic Outlook assumptions on Manitoba inflation. Non-commodity price changes in the post-IFF period were based on historical trends

Economic Variables – For the 2012/13 Power Smart Plan, the Projected Escalation, Interest, & Exchange Rates – G911 corporate policy document issued October 19th, 2011 was used to discount all forward-looking savings and costs. The real weighted average cost of capital was used to discount real dollar cash flows and energy savings. Where nominal costs and benefits were included, the weighted average cost of capital was used for discounting cash flows. Rates for all historical benefits, costs, and energy savings used actual economic results for each year.

1.4 RESIDENTIAL PORTFOLIO

The **Power Smart Residential Portfolio** consists of the following programs:

Customer Service Initiatives and Cost-Recovery Programs

Home Comfort & Energy Savings Program

The Home Comfort & Energy Savings Program encourages homeowners to make energy efficient renovations to increase comfort and reduce home heating bills. The following services are offered under this customer service program:

- Power Smart Do-It-Yourself Home Assessments
  - Mail-in Energy Assessment Survey
  - Online Home Comfort & Energy Assessment
- Existing Homes Energy Workshops
- Consumer Information Services
- Power Smart "Energy Expert"
- Power Smart Residential Loan (See Financial Loan Programs)

In addition to the above programs, Manitoba Hydro also provides customers with basic information on the energy saving opportunities via the following initiatives:

- Residential Seasonal LED Lighting
  - Encouraging the use of residential seasonal light emitting diode (SLED) light strings and SLED screw-in replacement bulbs for standard incandescent light strings.

- Residential CFL Lighting
  - Encouraging the replacement of residential incandescent lights with CFLs.

- Energy Efficient Light Fixtures Program
  - Encouraging the replacement of residential incandescent and halogen fixtures with ENERGY STAR qualified fixtures and installation of other energy efficient devices including dimmer switches and LED night lights.

- Standby Power
  - Educating and informing homeowners on the issue of standby power and its impact on energy consumption in the home, while also focusing on steps they can take to reduce the standby power used by their current devices, and promoting the purchase of new devices which use less standby power.

- Consumer Electronics
  - Promoting ENERGY STAR electronics by providing technical and general information, with a focus on Set Top Boxes and Televisions.

- Energy Efficient Appliances
    - Encouraging customers to buy energy efficient appliances for their homes. The ENERGY STAR symbol identifies the models that meet or exceed technical specification that is meant to ensure that they are among the most energy efficient in their class and do not compromise performance. ENERGY STAR appliances are 10–50 per cent more efficient than conventional models. When you buy an ENERGY STAR qualified appliance, you are being Power Smart.

- Residential High Efficiency Furnaces
    - Encouraging the replacement of old furnaces with a new ENERGY STAR qualified high efficiency furnace. A high efficiency natural gas furnace or boiler uses less energy, costs less to operate, helps conserve natural gas, and reduces greenhouse gas emissions.

Financial Loan Programs

Manitoba Hydro offers a variety of innovative and convenient financing options to assist customers in managing the upfront costs of upgrading the energy efficiency of their homes. Manitoba Hydro works through a wide network of retailers and contractors to deliver these convenient financing options along with many other Power Smart offerings.

Power Smart Residential Loan ^

As part of the Home Comfort & Energy initiative, Manitoba Hydro offers low interest and convenient on-bill financing, with a fixed interest rate for up to five years for Power Smart home renovations. The loan covers the following energy efficient upgrades:

- Windows and doors
- Residential space heating equipment;
- Insulation;
- Air leakage sealing;
- Ventilation;
- Residential water heating equipment

The current terms of the loan are as follows:

- Borrow up to $7,500 per residence. Up to $5,500 of that may be put toward the purchase of a high efficiency natural gas furnace.
- The maximum term is 5 years for all energy efficiency upgrades and 15 years for the purchase of a high efficiency natural gas furnace.
- Annual interest rate is fixed at 4.8 per cent (O.A.C.) for the first 5 years.
- Applicant must be a Manitoba Hydro customer and the owner of the home in which energy improvements are to take place.
- Upgrades must be made to levels recommended by Manitoba Hydro.
- The loan is not available for central air conditioning

Residential Earth Power Loan ^

The Residential Earth Power Loan offers convenient on-bill financing to assist homeowners with the cost of installing a geothermal heat pump and/or a solar water heating system.

Geothermal Heat Pumps

The Residential Earth Power Program's primary objective is to maximize the adoption of geothermal heat pump technology to offset the use of conventional electric heating. The program attempts to mitigate the market barriers of low customer awareness, underdeveloped industry infrastructure and high capital costs. Mitigation of capital costs is achieved by offering residential consumers the opportunity to finance a geothermal heat pump installation through the cost-recovery based Earth Power Loan.

The current terms of the loan are as follows:

- Financing up to $20,000;
- Maximum term: 15 years;
- Interest rate: 4.9 per cent (initial 5-year fixed term);
- Applicant must be a Manitoba Hydro customer and the owner of the home in which energy improvements are to take place; and
- Available for new installations and retrofits.

Solar Water Heating System

This initiative promotes harnessing the sun's power and transferring the energy to preheat water for water tanks. The program attempts to mitigate the market barriers of low customer awareness and high capital costs. Mitigation of capital costs is achieved through utilizing the cost-recovery based Earth Power Loan.

The current terms of the loan are as follows:

- Financing up to $7,500 per residence;
- Maximum term: 15 years;
- Applicant must be a Manitoba Hydro customer and the owner of the home in which energy improvements are to take place; and
- Interest rate: 4.9 per cent (for the initial 5-year fixed term).

Power Smart PAYS Financing

Power Smart for PAYS Financing is a new program expected to launch in the fall of 2012/13 through enabling provincial legislation, Bill 24: The Energy Savings Act, introduced in June 2012. The Program will offer convenient and affordable financing for residential customers who are considering doing energy efficient upgrades to their home. PAYS is a unique financing option when compared to other Manitoba Hydro financing programs as it is:

- transferable from one homeowner to another or from a landlord to a tenant;
- the monthly payment the customer makes to pay for the financing is based on the estimated bill savings that are achieved when installing the energy efficient measure being financed resulting in no net increase to their annual utility bill.

The objective of the program is to encourage customers to improve the efficiency of their home while minimizing their financial burden. The program will target all residential customers in Manitoba. Specific attention will be paid to lower income customers and landlords in situations where their tenants pay the energy bills.

The program offers low interest on-meter financing with the financing term dependent upon the technology financed, with a fixed interest rate for up to five years. Energy efficient upgrades that may qualify for financing are:

- Space heating equipment;
- Geothermal systems;
- Drainwater heat recovery systems;
- WaterSense toilets.

The current terms of the financing offering are as follows:

- Financing per project is dependent upon the estimated energy and resulting bill savings;
- Maximum term is dependent upon the measures being installed;
- Interest rate: 3.9 per cent (for the initial 5-year fixed term);
- Applicant must be a Manitoba Hydro customer; and
- Owner of the home in which energy improvements are to take place.

Note: ^ Program impacts classified as Customer Service Initiative in Appendices.

Incentive Based Programs

Home Insulation Program

The Home Insulation Program encourages existing homeowners utilizing electricity or natural gas to heat their homes to upgrade the insulation in their attics, walls, and foundations to Power Smart recommended levels. Information on best practices for installation and financial incentives are offered to encourage customer participation.

Water and Energy Saver Program

The Water and Energy Saver Program encourages customers to replace their existing inefficient showerheads and faucet aerators by offering with low-flow energy efficient showerheads and faucet aerators at no cost.

Lower Income Energy Efficiency Program (LIEEP)

The Lower Income Energy Efficiency Program (LIEEP) is designed to bring Power Smart and energy efficient measures to qualifying Manitoba lower income households. The program leverages Manitoba Hydro Power Smart programs, the Affordable Energy Fund, the Natural Gas Furnace Replacement Budget, provincial government programs and existing community-based infrastructures. Energy efficiency measures include pre and post in-home energy evaluations, installation of basic energy efficiency items such as CFLs and low-flow showerheads, insulation upgrades and natural gas furnace upgrades.

Refrigerator Recycling Program

The Refrigerator Recycling Program will provide pick-up and recycling services for customers to remove their old and working secondary fridges and freezers earlier than their expected end of life. The program is supported by a marketing campaign promoting the benefits of removing the older working appliance as well as a financial incentive to encourage customers to give up their appliance. The program is implemented through a third party service provider specializing in appliance removal and recycling.

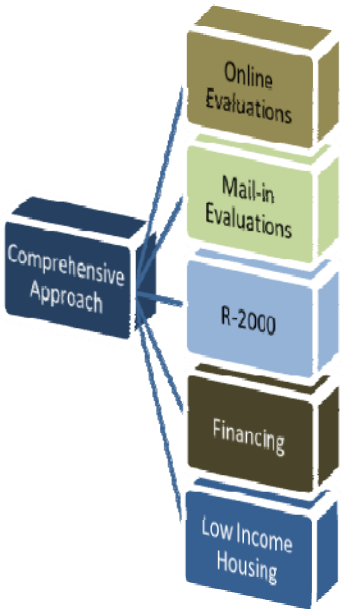
STRATEGY

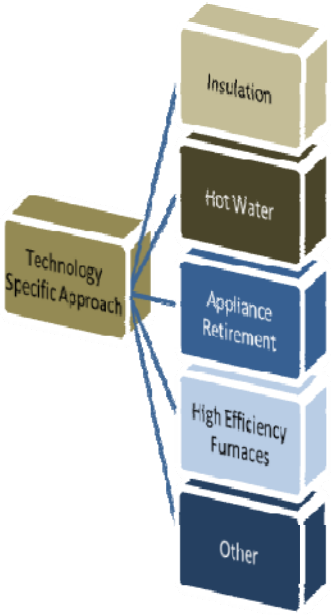
✓ **Comprehensive & Technology Specific Approach to Program Design**

Manitoba Hydro offers both comprehensive and technology-specific programs to residential customers.

Comprehensive programs advocate the "house as a system" approach to building a new home or renovating an existing home, in order to educate customers regarding the potential effects of changing a single feature of their new or existing home without assessing the implications of such a change.

Examples of comprehensive programs for existing homes are the Power Smart Residential Loan and the Lower Income Energy Efficiency Program.





Technology-specific programs supplement the existing comprehensive programs by providing additional technical and/or financial assistance to residential customers to further encourage the use of energy efficient techniques and products identified as having significant energy savings.

Manitoba Hydro currently offers the Power Smart Home Insulation Program, the Power Smart Water and Energy Saver Program and the Power Smart Refrigerator Retirement Program under the technology specific approach.

✓ **Integrated Approach to Program Design**

Power Smart residential programs are designed to offer eligible Manitoba Hydro residential customers maximum opportunities to save energy. By participating in either one or all of the available programs, customers will be able to maximize benefits when building their new home or retrofitting their existing home. Marketing strategies for all residential programs contain an element of cross-promotion to encourage the use of multiple programs.

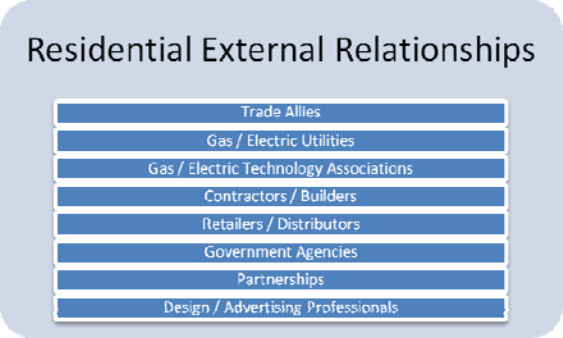
In the new home market, Manitoba Hydro continues to partner with Natural Resources Canada (NRCan) to deliver the R2000 and the EnerGuide for New Houses programs. Manitoba Hydro also has an ongoing partnership with Habitat for Humanity to provide funding and technical guidance to ensure long term energy affordability for all Habitat clients.

In the existing homes market, Manitoba Hydro continues to develop and support its network of registered Power Smart suppliers to deliver and/or promote residential programs.

✓ **Collaborative Approach**

Manitoba Hydro currently partners with NRCan to deliver the R2000 Program. Manitoba Hydro also collaborates with NRCan to promote initiatives such as Energy Star technologies and intends to continue this relationship with these programs and new initiatives in the future. Manitoba Hydro has also developed a relationship with the Natural Resources Institute, University of Manitoba to support ongoing housing research.

All Manitoba Hydro residential program design phases include a component to solicit input from industry stakeholders including the Manitoba Home Builders' Association, the Heating, Refrigeration and Air Conditioning Institute (HRAI), technology manufacturers and community groups where applicable. Programs are also reviewed on an annual basis in order to ensure that they meet the needs of stakeholders and targeted markets. This approach has been extremely effective in developing past programs and will continue to be used in all future designs. Manitoba Hydro also benefits from relationships with utilities across Canada through participating in the DSM Alliance, space heating task force, water heating task force, Standby Power committee, appliance forum, Strategic Lighting Initiative Committee and other national initiatives.



✓ **Leveraging Non-Energy Related Benefits**

Manitoba Hydro will continue to emphasize home comfort as the primary non-energy benefit to customers who increase the energy efficiency of their homes. Program promotion will continue to include information on the benefits of energy efficient products including reducing drafts, increased home resale value, reducing entry of exterior noise, increasing indoor air quality and maintaining healthy living environments. While energy savings translate into dollar savings for residential customers, benefits to the environment achieved through energy conservation will also continue to be communicated.

✓ **Leveraging the Power Smart & Energy Star Brand**

Manitoba Hydro promotes Energy Star technologies as being Power Smart where appropriate. The bringing together of the Energy Star and Power Smart brands results in the ability to communicate energy efficiency messages to a larger portion of the residential market, as there are customers who are familiar with Power Smart but not Energy Star, and vice versa. To avoid confusion in the marketplace, Energy Star is promoted and positioned to consumers with the slogan "Be Power Smart, Choose Energy Star

Products". The linking of these two brands allows Manitoba Hydro to benefit from Energy Star promotional activities undertaken by external parties, such as the federal government and retail chains.

✓ **Market Focused**

The primary residential market segments are new homebuyers and existing homeowners. Specific marketing strategies have been developed to respond to the unique characteristics of these two segments. The primary consideration is to capture lost opportunities for savings within these two segments. It is estimated that the existing home retrofit market represents 95% of achievable energy savings, while the remaining 5% will be realized from the new home market segment. Although the size of the new home market segment is significantly smaller than existing homes, the savings that can be achieved from this market segment are especially significant. In most cases it is easier and more cost-effective to incorporate energy efficient features into a home at the time of initial construction, and each new house that is built without energy efficient features means that it will be many years before the opportunity to incorporate these features will again present itself. Achieving market acceptance of energy efficient measures and technologies in the new home market is also likely to lead to adoption in the Manitoba Building Code, resulting in a complete market transformation of those technologies.

The marketing plan for targeting these market segments will continue to use a pull strategy; to induce customers to ask their builder, contractor or retailer about Power Smart energy efficient programs and technologies. Life-cycle costing and non-energy benefits such as increased comfort will continue to be emphasized in order to demonstrate the benefits of energy efficient technologies to homeowners.

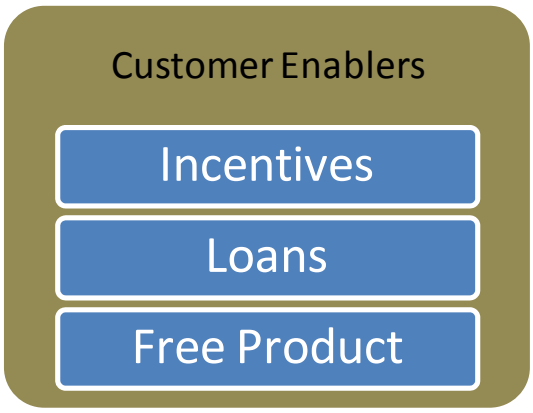
In addition to targeting homeowners who are the ultimate users and beneficiaries of energy efficient new and renovated homes, Manitoba Hydro recognizes the critical importance of the primary industry marketing channels: homebuilders, renovation contractors, building supply retailers and other retailers.

These sources can be very influential when it comes to the design and selection of materials for new homes and home renovation projects. In many instances, homeowners rely on these businesses to recommend or select the type of building material or technology to install in a new or existing home, based on the homeowner's needs and budget.

The marketing plan for this group will continue to employ a push strategy, complementing the pull strategy being utilized with consumers. Marketing tactics for this group seek to induce them to promote Power Smart energy efficient measures and products to their customers. These trade allies will be made aware of the specific benefits that supplying and/or installing energy efficient technologies can bring to their business. Building strong relationships with trade allies is critical to the success of Power Smart residential programs, as trade allies are utilized as delivery agents for a number of currently promoted programs and are crucial for the delivery of future programs.

✓ **Leveraging Financial Tools – Loans, Incentives, Rates and Service Fees**

The use of financial tools such as incentives is a powerful enabler that allows Manitoba Hydro to encourage residential customers to purchase and/or install energy efficient products and technologies. Financial incentives and low-interest loans address the most common market barrier to customer participation, the lack of available capital to purchase energy efficient products that are typically more expensive than their non-energy efficient alternatives.



Manitoba Hydro will continue to promote Power Smart financing to homeowners for energy efficient improvements and where appropriate, will continue to use incentives and grants to encourage adoption of energy efficient technologies.

✓ **Supporting Industry Infrastructure**

Manitoba Hydro currently provides technical expertise to homebuilders, renovators and retailers through technical training sessions and presentations.

As the delivery agent for R2000 Manitoba Hydro will continue to provide technical training and technical update sessions to ensure that homebuilders are well informed of energy efficient building techniques and technologies.

Manitoba Hydro will also continue to provide information sessions to industry associations, retailers and renovation contractors regarding the benefits of energy efficient technologies, and promote the benefits of selling and installing energy efficient technologies.

✓ **Exit Strategy - Codes and Standards**

Manitoba Hydro, through Power Smart programs, will continue to seek industry and market acceptance and adoption of increased energy efficiency standards for houses and equipment. Manitoba Hydro will continue to work with federal, provincial, and local agencies to recommend and support the adoption of energy efficient codes and standards on a proactive basis.

Examples of committees on which Manitoba Hydro is currently an active participant and will continue to be so are: Building Energy Management Manitoba, Steering Committee on Performance, Energy Efficiency and Renewables (SCOPEER), Illuminating Engineering Society of America, International Ground Source Heat Pump Association, Manitoba Building Standards Board, American Society of Heating Refrigeration and Air Conditioning Engineers, Canadian Electrical Association.

✓ **Promoting Innovation: Research and Development**

Manitoba Hydro's Power Smart Residential Group is sponsoring and/or participating in a number of research and development projects, both through the Manitoba Hydro Research Management Board, and through other partners.

Manitoba Hydro will continue to initiate, participate in and support research and development activities related to residential energy efficient products and installation methods and utilize the findings of such studies to determine the most effective program offerings to address market needs.

✓ **Leveraging the Corporation's Extensive Infrastructure and Broad Outreach Capabilities**

Power Smart's residential programs have been able to take advantage of Manitoba Hydro's outreach capabilities in a number of ways. The advent of the internet has allowed the communication of program information and the offering of programs via the corporate web site. Today, a customer can find information on any Power Smart residential program on the website, can access and download "how-to" information to complete energy efficient renovations, can fill out an on-line in-home assessment form or email the Power Smart Energy Expert to gain answers to energy-related questions. Trade allies offering the Power Smart Residential Loan are able to submit customer applications online and receive immediate application approvals. As internet technology advances further, Manitoba Hydro will utilize this technology to promote, deliver and increase participation in existing and future programs.

Manitoba Hydro's Contact Centre personnel, Energy Service Advisors, and District personnel throughout the province are the primary "front line" points of contact for residential customers to learn about and obtain information on Power Smart programs. District offices are utilized as distribution points for additional energy efficiency information and as specific promotional campaign outlets. Manitoba Hydro will continue to build upon this community presence to promote energy efficient products and services

1.5 COMMERCIAL PORTFOLIO

PROGRAMS & INTIATIVES

The **Power Smart Commercial Portfolio** consists of the following programs:

Financial Loan Programs

Innovative and convenient financing is an efficient and effective tool to assist customers in managing the upfront costs of upgrading the energy efficiency of their businesses and operations.

Power Smart for Business PAYS Financing

Power Smart for Business PAYS Financing is a new program expected to launch in the winter of 2012/13 through enabling provincial legislation, Bill 24 – The Energy Savings Act, introduced in June 2012. The Program will offer convenient and affordable on-meter financing for commercial customers who are considering undertaking energy efficient upgrades to their building. PAYS Financing will allow a property owner to use their estimated annual utility savings from installing an eligible efficiency measure to pay for that measure (or a part thereof). The objective of PAYS Financing is to encourage customers to improve the efficiency of their building while minimizing their financial burden. The Program will specifically target property owners who may be choosing not to do upgrades because they plan on selling their building in the near future or property owners such as small and medium businesses who have less ability to manage an increase to their monthly expenses.

The Program has three unique aspects. First, the loan is tied to the property instead of the customer, allowing the loan to be transferred from one property owner to the next with the new owner's consent. The monthly payment can also be transferred from property owner to tenant with approval. Second, the financing period will be longer allowing for a lower monthly finance payment (principle and interest). Third, the amount of financing a customer can borrow is dependent on the customer's estimated utility savings generated by the upgrade. PAYS Financing is intended to be offered for those retrofits where the expected energy bill reductions are significant enough to offset the financing payments thereby leaving the property owner with no net increase to their annual utility bills. The interest rate charged will be a cost recovery rate fixed for five years with the amortization period of the loan being dependent upon the measures undertaken.

The financing program will cover various energy and water efficiency upgrades including:

- Heating and ventilation systems – high efficiency furnaces, boilers, CO2 sensors and Geothermal heat pumps (maximum financing term is 20 years for heating equipment and 10 years for CO2 sensors);
- Insulation (maximum financing terms is 25 years);
- Lighting (maximum financing terms is 20 years);
- Technologies approved through the Commercial Custom Measures program (maximum financing term depends on the measure);
- Watersense labelled toilets and urinals (when financed with an energy saving measure).

Incentive Based Programs

Commercial Lighting Program

The Commercial Lighting Program encourages commercial, industrial and agricultural customers to install cost-effective energy efficient lighting systems in new construction and renovation projects as well as provide assistance to lighting distributors, installers, contractors and manufacturers with helping customers save electricity.

Custom Measures Program

The Commercial Custom Measures Program encourages commercial customers who are renovating, undergoing expansions or building new facilities to improve system performance by installing or upgrading technologies such as direct digital controllers, variable frequency drives, heat recovery ventilation systems and solar space and water heating. The program is designed for energy efficient projects that are not included in any of the existing POWER SMART programs.

Commercial Building Envelope - Windows and Insulation Programs

This program encourages building owners to incorporate window systems and/or insulation that meets POWER SMART levels into their renovation plans and helps to reduce air leakage that leads to heat loss.

Commercial HVAC Program - Chillers

The program promotes the use of higher efficiency cooling systems in commercial buildings through the installation of energy efficient water-cooled chillers.

Commercial HVAC Program - Boilers

The program promotes the use of higher efficiency heating systems in commercial buildings through the installation of near condensing and condensing boilers.

Commercial HVAC Program - CO2 Sensors

The Commercial CO2 Sensor Program promotes the installation of carbon dioxide demand-controlled ventilation sensors through financial incentives and promotional activities, as well as increasing the levels of education to customers and channel intermediaries.

City of Winnipeg Power Smart Agreement

The City of Winnipeg Power Smart Agreement (PSA) encourages, promotes and implements energy saving measures to improve the efficiency of City-owned facilities

Commercial Refrigeration Program

The Commercial Refrigeration Program encourages retail stores and restaurants to install energy efficient refrigeration equipment for their walk-ins, display cases and mechanical rooms to reduce energy consumption and create a more comfortable environment for their customers.

Commercial Earth Power Program

The Commercial Earth Power Program provides information and financial incentives to customers who install a geothermal heat pump to offset a conventional electric heating system or for customers without access to natural gas in existing commercial buildings.

New Buildings Program

The Power Smart New Buildings Program provides technical guidance and financial incentives for designing, constructing, and operating new, energy efficient buildings in Manitoba.

Commercial Building Optimization Program

The Commercial Building Optimization Program encourages commercial customers with existing buildings to use an investigation process known as "retrocommissioning" to help return their buildings to their design intent. The goal is to identify primarily operational energy conservation opportunities with short payback periods.

Internal Retrofit Program

The Internal Retrofit Program encourages energy efficiency in Manitoba Hydro buildings by retrofitting existing buildings and constructing new buildings to POWER SMART levels.

Commercial Kitchen Appliance Program

The Commercial Kitchen Appliance Program promotes the installation of ENERGY STAR commercial natural gas and electric steam cookers and natural gas fryers.

Network Energy Management Program

The Network Energy Management Program is a software-technology based program offering an incentive to commercial customers utilizing personal computers (PCs) in a network setting.

Commercial Clothes Washers

The Commercial Clothes Washer Program promotes ENERGY STAR® qualified front-loading commercial clothes washers (Washers) while raising awareness of lower operating costs and increased water savings.

In addition to the above programs, Manitoba Hydro also provides commercial customers with basic information on the energy saving opportunities via the following initiatives:

- Power Smart Recreation Facility Survey
- Religious Buildings Initiatives

STRATEGY

✓ **Comprehensive & Technology Specific Approach to Program Design**

The Power Smart New Buildings Program was developed to encourage the design and construction of energy efficient commercial buildings in Manitoba. The program focuses on integrated design, building simulation, building commissioning and energy management. This program supports customers and industry professionals with financial incentives and technical support so that they might explore and implement emerging techniques and construct high performance buildings in Manitoba.

The program takes a whole building approach to ensuring that owners undertaking a new construction or a major renovation project achieve a building that will operate at least 33% more efficiently than a facility built to meet the Model National Energy Code for Buildings (MNECB). The program standard of 33% more efficient than MNECB, has also been referenced for the Green Building Policy for Government of Manitoba Funded Projects. A dedicated Power Smart team is designated to each new building project to offer guidance throughout the design and construction phases of the new energy efficient building. The program offers greater flexibility by allowing customers to choose one of two paths for their project - a prescriptive path or a custom building design path.

Similarly, the Commercial Building Optimization Program utilizes a whole building approach to energy efficiency by recommending strategies identified through an investigation process, with additional focus on documentation and training to realize persistence of savings. The program aims to improve the overall operation and maintenance of building systems to meet the owner's operational needs, while using only as much energy as necessary.

Other comprehensive offerings which Manitoba Hydro promotes include Manitoba Hydro's Recreation Facility Survey Initiative, Recreation Facility Energy Efficiency Guide, Energy Efficiency Guide for Religious Buildings and the newly developed Energy Efficiency Guide for Commercial Buildings. The aforementioned offerings are all offered free of charge to customers.

Manitoba Hydro's technology-specific or prescriptive programs remain very successful and fulfill a market need within the commercial and institutional customer base, primarily with those customers planning staged retrofits of existing facilities.

A number of technology-specific programs have recently successfully accelerated the natural adoption curve of the technology in question, reaching the point where the market was deemed "transformed", thus allowing Manitoba Hydro to cease offering financial incentives. These major recent milestones have been met by the following programs: the Commercial Furnace Program, the Commercial Rinse & Save Program, the Municipal Seasonal LED Lighting Program, the Agricultural Heat Pad Program, and the Commercial Parking Lot Controller Program.

A summary of the status of Manitoba Hydro's Power Smart for Business programs follows:

Program / Initiative	Technology-specific	Comprehensive	Strategic Plan
Commercial Lighting Program	√		Deploy channel strategy, new technology assessment.
Commercial Custom Measures Program	√		Review incentives, revise channel strategy.
Commercial Windows Program	√		Deploy channel strategy.
Commercial HVAC Program – Chillers	√		Deploy channel strategy.
Commercial Refrigeration Program	√		Review incentives, new technology assessment.
Commercial Insulation Program	√		Deploy channel strategy.
New Buildings Program		√	Deploy channel strategy.
Commercial Building Optimization Program		√	Review incentives, new technology assessment.
Commercial Kitchen Appliances Program	√		Deploy channel strategy.
Commercial Clothes Washers Program	√		Deploy channel strategy.
Network Energy Management Program	√		Deploy channel strategy.
Commercial HVAC Program – CO2 Sensors			Deploy channel strategy.
Commercial HVAC Program – Boilers			Deploy channel strategy.
Agricultural Heat Pad Program	√		Market successfully transformed, program closed.
Commercial Parking Lot Controller Program	√		Market successfully transformed, program closed.
Commercial Rinse & Save Program	√		Market successfully transformed, program closed.
Recreational Facilities		√	Deploy channel strategy.
Religious Buildings		√	Deploy channel strategy.
Commercial Furnace Program			Market successfully transformed, program closed.
Energy Efficiency Guide for Commercial Buildings		√	Deploy channel strategy.
Municipal Seasonal LED Lighting Program	√		Market successfully transformed, program closed.

✓ **Integrated Approach to Program Design**

Power Smart for Business programs are designed to offer eligible Manitoba Hydro commercial customers maximum opportunities to save energy. Through participation in either one or all of the available programs, customers will be able to maximize benefits when building a new facility or retrofitting an existing operation. Developed to enable customers to utilize a streamlined process to access incentives and technical support historically available through a number of separate Manitoba Hydro Power Smart programs, the Power Smart New Buildings Program has proven to be a great success, signaling a demand in the market for further introduction of streamlines processes. Investigation will continue in the area of streamlined processes for the various existing renovation programs.

✓ **Collaborative Approach**

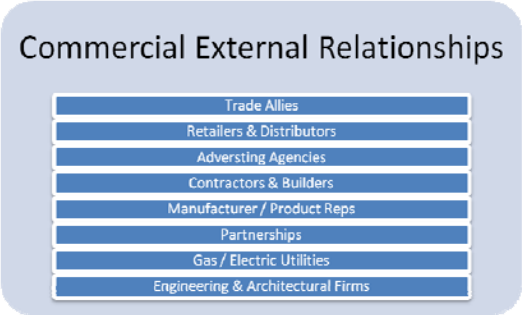
Manitoba Hydro Power Smart for Business staff will continue to seek collaboration opportunities to align its goals with those of other stakeholders. One such opportunity will exist through fulfilling a role in a pioneering group to improve efficiency of existing buildings. Created from the Green Building Policy for Government of Manitoba Funded Projects which authorized the future development of green building standards for existing buildings, select Manitoba Hydro Power Smart for Business staff members have joined the steering committee and working group for a provincial interdepartmental working group focusing on existing building standards and practices. The scope of the policy has been defined to apply to

government, government agencies and any entity that receives government funding which is used to pay all or a significant portion of the occupancy and maintenance costs of the building or the part of the building that it occupies. Manitoba Hydro has a significant stake in the success of this project, as it applies to both the energy efficiency transformation of existing building stock, as well as its own existing buildings being subject to the policy directive.

Power Smart for Business staff are also working closely with the Residential Tenancies Branch (RTB) of Manitoba. Power Smart for Business is being consulted on minimum energy efficiency requirements RTB is considering putting forward to landlords that are submitting an application for a rent increase above the guideline due to significant capital investments in their properties. Efforts are underway to align the minimum energy efficiency requirements for exemption from rent increase guidelines, with the Power Smart for Business requisite levels.

Manitoba Hydro will continue to work closely with Natural Resources Canada (NRCan) and in particular the Office of Energy Efficiency, in the cross-marketing of any new federal commercial incentive programs or other initiatives, to ensure that programs are aligned and harmonized to maximize energy efficient opportunities for the customer, and to leverage available federal monies.

Manitoba Hydro initiates ongoing collaboration directly with industry professionals in the reviews of its existing programs and in the development of any new programs. Industry teams are formed and consulted in the redesign or design of any future program offerings; this approach has been extremely effective in developing past programs and will continue to be used in all future designs.



✓ **Leveraging Non-Energy Related Benefits**

Power Smart for Business programs will continue to be marketed to customers with an entire benefit package that goes beyond energy savings. For all advertising material produced to date, benefits have communicated that Power Smart will:

- lower maintenance costs;
- facilitate longer equipment life;
- increase customer and worker comfort;
- improve system performance and production rates; and
- facilitate labor savings.

Building upon the existing Power Smart for Business campaign, a sector-specific target marketing campaign will take an even more specific approach regarding non-energy benefits depending on key drivers of the targeted sector (e.g. such as increasing occupancy rates for property managers).

✓ **Leveraging the Power Smart & Energy Star Brand**

Continued effort is planned to achieve an increased awareness and understanding of Power Smart for Business programs. The goal being that when a commercial customer is in the market for renovations or undertaking new construction, they will recall that there are energy efficient options available and they will contact Manitoba Hydro.

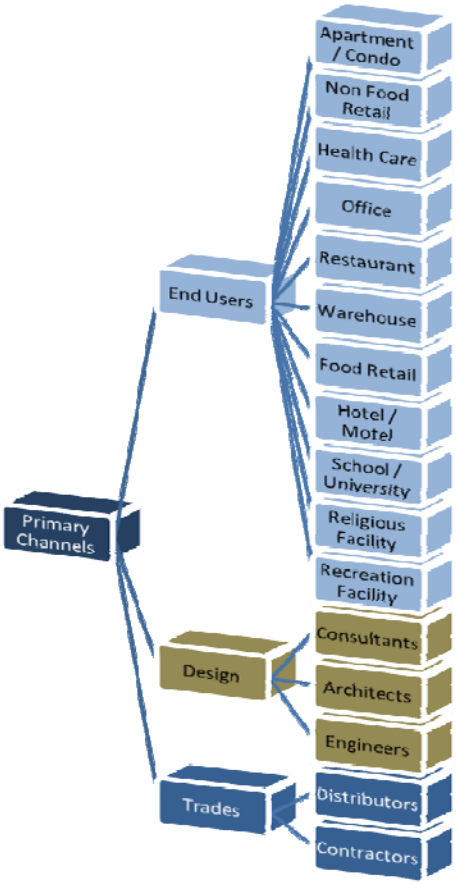
Manitoba Hydro was awarded the ENERGY STAR Participant of the Year award at the 2010 ENERGY STAR Market Transformation Awards. This was the third ENERGY STAR Recognition Award for Manitoba Hydro, which won the award for Promotional Campaign of the Year in 2005 and for Utility of the Year – Provincial in 2006.

Power Smart for Business will continue to target savings available through the adoption of ENERGY STAR qualified equipment. The ENERGY STAR brand will be leveraged through inclusion in Power Smart incentive programs, and promotion through Power Smart Energy Efficiency Guides. Two current programs, the Commercial Kitchen Appliance Program and the Commercial Clothes Washers Program, promote the installation of ENERGY STAR qualified equipment. Additional ENERGY STAR qualified equipment has been identified as new program development opportunities in fiscal year 2012/13

✓ **Market Focused**

- Primary Market Channels

Power Smart for Business programs focus on three primary market channels: the end user commercial customer; design professionals including consultants, architects and Engineers; and lastly, trade channel members including distributors and contractors. Design professionals and trade channel members act as intermediaries between end user commercial customers and Manitoba Hydro's Power Smart for Business programs.



- Secondary Market Channels

A number of additional secondary market channels also exist, and are fully leveraged to promote and disseminate Power Smart for Business program information to the aforementioned three primary market channels. An extremely efficient and cost-effective channel of promotion, relationships are forged, fostered and maintained with a number of crucial customer and industry associations.

- Customer Associations

Dealing with these associations allows specific promotion of select programs or features of Power Smart for Business that resonate specifically well with certain sectors that share similar opportunities or challenges. For example, the restaurant and food service sector present unique opportunities to reduce energy consumption associated with high energy intensity in the cooking and food preparation areas. Accordingly, working with the Manitoba Restaurant and Foodservice Association has proven a very fruitful endeavor for the success of select Power Smart programs offering solutions in these areas. Other key customer associations include but are not limited to: the Professional Property Managers Association, Building Owners and Managers Association, Manitoba Hotel Association, and the Manitoba Association of School Business Officials.

- Industry Associations

Regardless whether an association is comprised of mechanical contractors, lighting system designers, or building envelope professionals, capacity building and promotional opportunities exist allowing select Power Smart programs to be focused upon. Gaining buy-in from the applicable design professionals and trade channel members has proven to be an imperative component in allowing a Power Smart program to gain and maintain traction in the market. Key industry associations include but are not limited to: the Mechanical Contractors Association of Manitoba, Illuminating Engineering Society, Manitoba Building

Envelope Council, Manitoba Association of Architects, and the Association of Professional Engineers and Geoscientists of the Province of Manitoba.

- Promotional Strategies

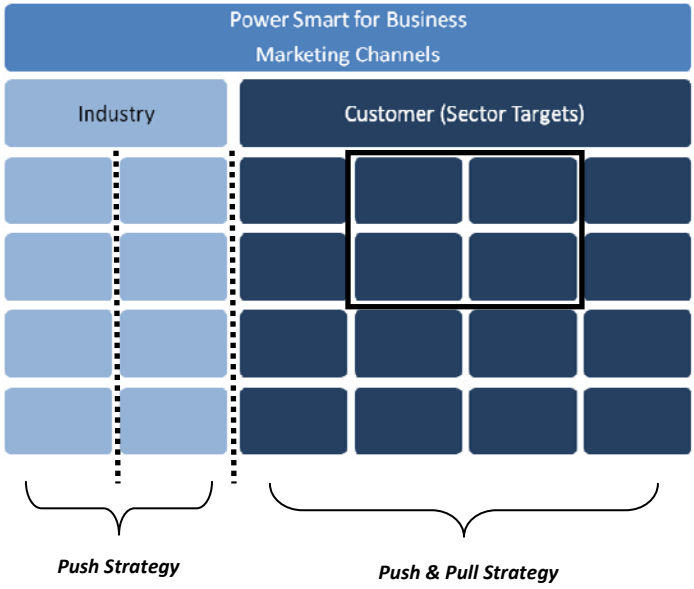
Channel promotional strategies for fiscal year 2012/13 include:

- End User Commercial Customer

Call-to-action and awareness advertising targeting end user commercial facility decision makers, and business and property owners and managers. Campaigns are supplemented by print materials, website content, the Power Smart for Business electronic newsletter, tradeshows and presentations, and Power Smart Sales staff customer intervention.

- Design Professionals and Trade Channel Members

Capacity building, awareness and call-to-action advertising, direct communication, education and training for design professionals and trades, supplemented by print materials, website content, the Power Smart for Business electronic newsletter, tradeshows and presentations, and industry intervention by Marketing Programs, Power Smart Sales, and Customer Engineering staff.



As in previous years, marketing materials and advertising campaigns will continue to reinforce the stalwart theme of the financial benefits of energy savings, however, the complimentary call-to-action tagline of “We’ll show you how” has been added to Power Smart for Business creative. “We’ll show you how” is used as a platform to communicate the value proposition presented to customers by way of the various in-kind services available through Manitoba Hydro Energy Services and Sales field staff, along with Engineering staff within the Customer Engineering Services area. In-kind services promoted to end users include site walk-throughs to help identify opportunities, customized proposals, access to technical Engineering expertise, and unbiased evaluation of potential energy efficient upgrades.

Manitoba Hydro Power Smart for Business will continue to examine opportunities for sector-specific target marketing campaigns, similar to the recently created "Power Smart Program for Landlords" brochure to property managers and landlords of multiunit residential buildings in Manitoba. The goal was to ensure that property managers and landlords are fully aware of the various energy efficiency opportunities that exist within their buildings, including opportunities to increase energy efficiency within the tenants’ suites as well.

To further build on the Power Smart for Business customer relationship, customer recognition messaging will continue to be reinforced. The goal is to recognize customers for their participation in Power Smart for Business programs and for making an environmentally responsible choice for their business. This messaging will be supported by the growing awareness of commercial customers about the environmental impact of their actions, and the interest from businesses in promoting their environmental initiatives and efforts.
Select customers will be recognized for their participation in the Power Smart for Business programs by being featured in written profiles circulated within their sector of business, as well as circulated to their own current and possible future patrons. In addition to written profiles for select customers, all Power Smart for Business participants are provided with a Power Smart for Business “Efficiency Partner” participation label that can be affixed to their building. These recognition initiatives appeal to the end user customer target audience by way of:

- providing recognition for choosing environmentally responsible technologies;
- providing a reward to customers by allowing them to communicate their participation in Power Smart programs to their own customers and peers;
- offering an identifiable symbol visible to customers, staff and visitors; and
- reinforcing Power Smart for Business as a tool to gain a competitive advantage for business owners through communication of environmental stewardship.

✓ **Supporting Industry Infrastructure**

Manitoba Hydro continues to be a key contributor to the training and education of design professionals and trade channel members, both of which are critical to the successful delivery of Power Smart to the end user. Power Smart program staff regularly conduct education and training strategy sessions to ensure that the channels have the tools and information required to promote Power Smart for Business programs. These capacity building exercises are critical to program success.

Significant recent examples of the types of initiatives that are reviewed on an ongoing basis, include Manitoba Hydro hosting eSim in collaboration with the National Research Council of Canada. This was the 6th biennial conference of Canada’s chapter of the International Building Performance Simulation

Association (IBPSA-Canada). eSim is the leading conference for strengthening the building performance simulation community, promoting sustainable design practices, and showcasing various building simulation software and modeling methods. In total, the event brought together over 80 professionals, academics and students interested in building simulation.

In 2011, Manitoba Hydro in collaboration with the National Building Envelope Council, undertook its capacity building efforts through financial, technical in-kind, and co-hosting support of the 13th Canadian Conference on Building Science and Technology. Held in Winnipeg for the first time in its 25 year history, the event helped build capacity locally in the areas of building science and technology, with a focus on Manitoba applicability. The conference emphasized new innovations and ideas still under development in the building science industry, while illustrating how past techniques and technologies have impacted building design of the present day, with a focus on application within Manitoba. A great success, the conference attracted close to 200 delegates including local, national and international representatives.

✓ **Exit Strategy - Codes and Standards**

Power Smart for Business staff will continue to seek industry and market acceptance of increased energy efficiency standards for commercial buildings. Manitoba Hydro will continue to work with federal, provincial and local agencies to recommend and adopt energy efficient codes, standards and regulations on a proactive basis.

Examples of committees that Manitoba Hydro is active on and will continue to be active on are: Building Energy Management Manitoba, Steering Committee on Performance, Energy Efficiency and Renewables (SCOPEER), Illuminating Engineering Society of America, International Ground Source Heat Pump Association, Manitoba Building Envelope Council, American Society of Heating Refrigeration and Air Conditioning Engineers and the Canadian Electrical Association.

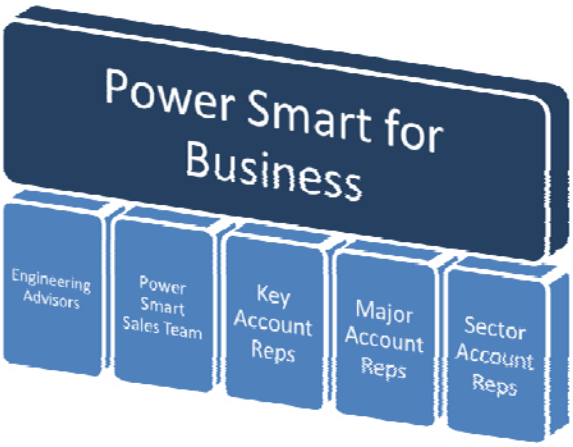
✓ **Promoting Innovation: Research and Development**

Manitoba Hydro will continue to partner with other industry and government stakeholders for research and development projects that will further efficiency standards in Manitoba, such as recent proposals in the area of building envelope air tightness testing and window energy rating (ER) testing.

Manitoba Hydro will continue to initiate and participate in research and development activities related to commercial energy efficient products and installation methods, and utilize the findings of such studies to determine the most effective program to address market needs.

✓ **Leveraging the Corporation's Extensive Infrastructure and Broad Outreach Capabilities**

The future success of Power Smart in the commercial sector will rely heavily on the existing infrastructure. Key Account representatives, Major Account representatives, Energy Service Advisors and Power Smart Sales representatives will continue to play a key role in promoting Power Smart initiatives and services to their customers. Customer Engineering Services will continue to provide technical support and services to Power Smart for Business initiatives. The Market Forecast department will provide support through end-use information, market demographics and take-up rates for potential program offerings. These internal resources will continue to support future development and delivery of Power Smart for Business Programs.



1.6 EARTH ENERGY & EMERGING TECHNOLOGIES

STRATEGY

✓ **Comprehensive & Technology Specific Approach to Program Design**

The Earth Power Loan Program was designed to assist consumers with the high capital cost of installing a geothermal heat pump. Residential customers were initially provided with the opportunity to finance up to $15,000 of the installation of a geothermal heat pump system over a term up to 15 years at a fixed rate of 6.5%. In 2007, the loan term was adjusted to meet market conditions, and continues today to offer financing of up to $20,000 over 15 years at a subsidized fixed rate of 4.9%. Over $19 million dollars has been financed to approximately 1,150 customers installing geothermal heat pumps throughout the Province.

In 2009, the Earth Power Loan was expanded to include solar water heating systems. The loan offers maximum financing of $7,500 over 15 years at 4.9%.

The Earth Power Loan will continue to investigate other emerging technologies that may be added to this suite of technologies included potentially solar photovoltaic systems and small wind generation.

Manitoba Hydro looks at commercial emerging technologies both from a comprehensive and technology based approach. From a comprehensive approach, through the Power Smart New Buildings program which was developed to encourage the design and construction of energy efficient buildings in Manitoba, geothermal heat pumps may be integrated into the design of new building in an electric serviced area to lower the electric heating costs and build a more sustainable and comfortable working environment for its tenants.

From a technology approach, the Commercial Geothermal program offers prescriptive incentives to customers who install a geothermal heat pump system to replace a conventional electric heating system. As well, the Custom Measures program can offer prescriptive incentives for technologies that do not fall into an existing Power Smart commercial program, such as solar hot water heating and drain water heat recovery.

✓ **Integrated Approach to Program Design**

While Power Smart programs are designed to offer Manitobans maximum opportunities to save energy, EEET is also committed to assisting with the high capital cost of these new technologies and building the industry and infrastructure needed to support these technologies.

The first emerging technology to be included in the Power Smart suite of programs was geothermal heat pump technology through the Commercial Construction & Renovation Program in 1996. At that time, the support was limited to financial incentives for commercial customers installing geothermal heat pumps to offset a conventional electrical heating/cooling system. The development of the Earth Power Program expanded Manitoba Hydro's focus on geothermal heat pumps from strictly commercial customers to include the residential market by introducing the Residential Earth Power Loan program. This program offered financing to residential customers installing a geothermal heat pump system to help mitigate the initial high capital cost of the system.

Manitoba Hydro also addressed the lack of awareness and industry infrastructure by assisting in the start-up of a local geothermal heat pump association, the Manitoba Geothermal Energy Alliance (MGEA). By providing funding and partnering in industry training opportunities, awareness of the technology grew in the Province substantially over a short period of time and there are now over 100 professionals trained on the installation of geothermal heat pump system in Manitoba. This group is now very well established and is made up of drillers, installers, designers, suppliers, and manufacturer/distributor reps.

In 2008, Manitoba Hydro began to promote another technology that did not have an established infrastructure to fully support installations. In a contribution agreement with the Federal Government of Canada, Manitoba Hydro launched a solar water heating Initiative to target both new and existing homes throughout Manitoba with domestic hot water demand. The program promoted the installation of solar water heating systems in residential homes throughout Manitoba by increasing awareness of solar heating technologies and applications, developing the solar industry and infrastructure by providing training to assist installers to become CANSIA certified and offering financial incentives for upgrading to this water heating alternative.

✓ **Collaborative Approach**

Manitoba Hydro continues to partner with MGEA, using their contractor certification process as an eligibility requirement in all geothermal heat pump driven programs therefore providing a consistent form of support to maintain the function and longevity of the organization.

Manitoba Hydro also works closely with the Department of Innovation, Energy & Mines (IEM) at the Province who has its own suite of geothermal grants and tax credits. Together, the three groups (MGEA, IEM and Manitoba Hydro) have begun developing a stakeholder committee whose objectives are to obtain reliable data regarding the state of the industry for future development and planning.

When new technologies enter the market or when reviewing current programs, Manitoba Hydro continues to consult with industry professionals, industry associations and any other stakeholders. This approach has been extremely effective in developing past programs and will continue to be used in all future designs.

✓ **Leveraging Non-Energy Related Benefits**

Each new technology that enters the market brings something different to the end user but one that will continue to remain important when promoting the technology is the non-energy benefits. Examples include increased home/office comfort, reduced environmental impact, increased resale value, reduced maintenance costs, longer equipment life, increased indoor air quality and maintaining healthy living/working environments. In the emerging technology sector, often these non-energy benefits are very important drivers to the customer and therefore will continue to be communicated in future marketing and educational pieces as an important addition to the value proposition.

✓ **Market Focused**

The Earth Energy & Emerging Technology (EEET) section looks at emerging technologies entering the market in both the residential and commercial sectors. As many of these technologies come at a much higher cost until adopted on a large scale, the section focuses on educating consumers and building capacity in the market, supporting the industry to ensure there is sufficient resources and training opportunities, and if feasible, offer incentives or financing to promote early adoption.

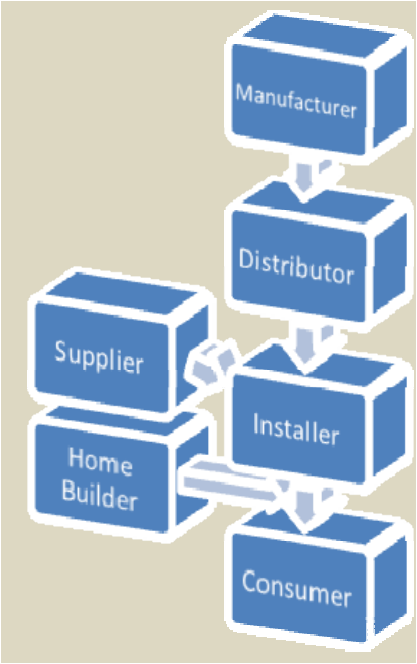
Because the section looks at both commercial and residential customers, the strategies to promote to each segment are tailored as such.

A typical residential consumer seeking emerging or earth energy technologies tends be financially stable with disposable income, are concerned about being good stewards of the environment for their community, and are early adopters.

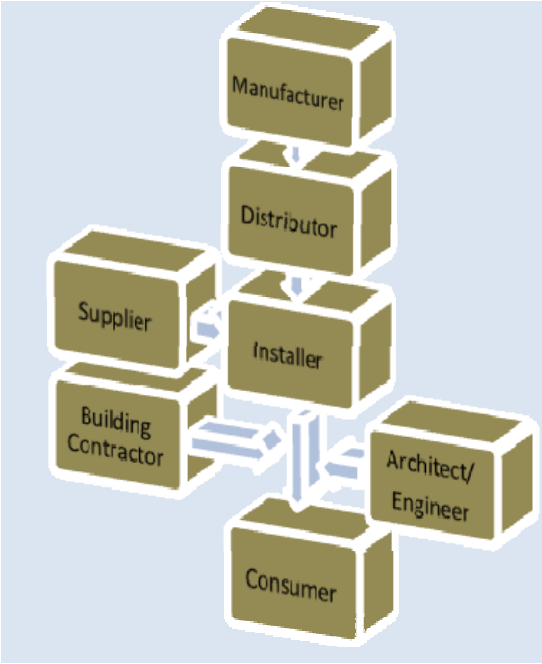
A typical commercial customer is looking for ways to reduce building operating costs or use low energy costs as a selling feature to lease clients. They want to be seen as leaders in their industry in terms of being environmental conscious while using the latest technology.

To reach these customers, a push strategy is used with the contractors and installers being the primary advocates of the program. For commercial customers, a pull strategy is also used but it goes beyond the contractors and distributors; it also relies on industry associations and design professionals such as architects and engineers.

Residential Supply Chain



Commercial Supply Chain



✓ **Leveraging Financial Tools – Loans, Incentives, Rates and Service Fees**

Manitoba Hydro uses financial tools such as incentives and financing options to encourage residential and commercial customers to purchase and install energy efficient products and technologies. Financial incentives and low-interest loans address the most common market barrier to customer participation, the lack of available capital to purchase energy efficient products that are typically more expensive than their non-energy efficient counterparts.

✓ **Supporting Industry Infrastructure**

Manitoba Hydro will continue to partner with associations such as the Heating, Refrigeration and Air Conditioning Institute of Canada (HRAI) and MGEA to support the development of the geothermal heat pump industry in Manitoba. Through course subsidies and promoting the technology to heating and ventilation contractors in addition to consumers, supply availability will increase along with demand.

Manitoba Hydro will also continue to be a key contributor in education and training opportunities to industry associations, trades, contractors and design professionals regarding the benefits of energy efficient technologies and successful delivery

✓ **Exit Strategy - Codes and Standards**

Due to the nature of emerging technologies, codes and regulations are typically not considered in the shorter term as the new technology is still gaining acceptance and awareness among consumers and, at times, the capacity in the marketplace for industry to delivery and install the technology is still in its infancy. A more focused approach is therefore taken on building the industry including strategies to ensure there are a sufficient number of installers/distributors/contractors and to assist the market in making the technology becomes more affordable by finding ways to break down the high cost barrier. Once the product becomes mainstream in the market, it is no longer considered 'emerging' and a longer term exit strategy is developed. Codes however are employed as a long term strategy only after careful consideration of the technology. For example, ground source heat pumps may not be a successful technology to introduce into building code due to the vast differences in land availability and drilling conditions for each customer; these factors can have a significant impact on installation costs. That, coupled with the cost of conventional sources of energy, may not make it economically feasible for a customer to install. The focus in this case would be working towards a longer term achievement of technology penetration rates as an exit point for program intervention in the market.

Standards are a strategy that is pursued with emerging technologies with the work tending to focus on developing performance and testing standards to ensure consistency and quality installations are being enforced and measures of efficiency are being established to assist the market transformation process of the efficient technology.

✓ **Promoting Innovation: Research and Development**

Ongoing technology research is of particular importance to the EEET section as the newer and emerging energy efficiency opportunities are the focus of the group. EEET will continue to initiate, participate in and support research and development activities with other industry and government stakeholders related to energy efficient products or projects and installation methods, and utilize the findings of such studies to determine the most effective program offerings to address market needs. For example, the Performance of Ground Source Heat Pumps in Manitoba study that was co-funded by Manitoba Hydro

and the Canadian GeoExchange Coalition in 2009 and the Solar Hot Water Heater Study which is in its final reporting stages and was sponsored by Natural Resources Canada

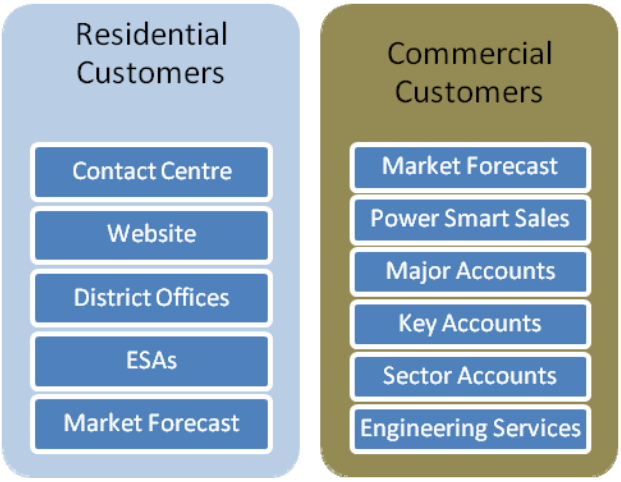
✓ **Leveraging the Corporation's Extensive Infrastructure and Broad Outreach Capabilities**

Manitoba Hydro's existing infrastructure plays a vital role in the outreach of its Power Smart programs.

The corporate web site is a communication tool to educate consumers about the new technologies and program offerings. The Earth Power Loan calculator makes it easy for contractors to obtain loan information during the approval process. The Earth Power Info email address gives customers a direct channel of communication with the program coordinators. Education videos on how solar hot water heating and geothermal heat pumps work are also available for viewing. As internet technology advances further, Manitoba Hydro will utilize this technology to promote, deliver and increase participation in existing and future programs.

Manitoba Hydro's Contact Centre personnel, Energy Service Advisors, and District personnel throughout the province are the primary "front line" points of contact for residential customers to learn about and obtain information on Power Smart programs. District offices are utilized as distribution points for additional energy efficiency information and as specific promotional campaign outlets. Manitoba Hydro will continue to build upon this community presence to promote energy efficient products and services. The Market Forecast department will provide support through end-use information, market demographics and take up rates for potential program offerings.

Key Account representatives, Major Account representatives, Energy Service Advisors and Power Smart Sales representatives will continue to play a key role in promoting Commercial Power Smart initiatives and services to their customers. Customer Engineering Services will continue to provide technical support and services for emerging commercial applications.



1.7 INDUSTRIAL PORTFOLIO

PROGRAMS & INTIATIVES

The **Power Smart Industrial Portfolio** consists of the following programs:

Incentive Based Programs

Performance Optimization Program
The Performance Optimization Program encourages industrial and large commercial customers to study and implement energy efficient measures in their electro-technology processes and motor-driven systems. The program offers Custom Engineered Solutions (inclusive of compressed air, pump, fan and process system initiatives) Eco-efficiency Audits & Feasibility Studies, Energy Management Systems and Waste Stream Thermal Recovery systems.

Industrial Natural Gas Optimization Program
The Industrial Natural Gas Optimization Program provides industrial and large commercial customers with technical support and financial incentives necessary to identify, investigate and implement systematic efficiency improvements throughout their facility.

In addition to the above programs, the Industrial portfolio consists of the following Customer Service initiatives:

- Consumer Information Sheets
- High Efficiency Motor Market
- Industrial Technology Workshops
- Engineering Expertise
- Managing customer energy strategically
- Building envelope & infrastructure
- Process & motive power systems
- On-site generation & heat recovery
- Power quality analysis

STRATEGY

✓ **Comprehensive & Technology Specific Approach to Program Design**
Market focused strategies for this sector includes a mix of comprehensive programs, technology specific programs and customer service programs.

Comprehensive programs, complete with custom incentives, are utilized to help customers fully realize the benefits available from using the “system approach” and to provide a consistent basis for making capital rationing decisions between projects. In many cases, a customer may be aware of a significant number of potential opportunities but they may not feel confident in setting priorities based on energy savings.

The custom incentive for studies assists the customer in quantifying the benefits of the project, and the custom incentive for implementing the project helps encourage the maximum amount of energy efficiency savings to be realized. The monetary amount of the incentive is based on amount of energy saved but also includes the value of non-energy benefits in the calculations. The Performance Optimization, Natural Gas Optimization, and Bioenergy Optimization programs are comprehensive offerings.

Technology specific program elements are used for customer simplicity, positive reinforcement of stand-alone measures and where appropriate to reinforce Power Smart branding with a monetary value. These usually entail a prescribed incentive of a fixed amount for a specific measure.

Technology specific program concepts are currently used in the lighting program, and for a small horsepower variable speed drive program.

Manitoba Hydro offers five specialized services to help businesses manage their energy and three specialized services to help customers grow their businesses strategically:

Managing Customer Energy Strategically

- Energy Monitoring, Analysis and Control – the knowledge customers require. Energy systems staff can develop customized energy monitoring, analysis and control systems for unique facility operations.

- Building Envelope and Infrastructure – the technologies to apply. Commercial systems staff can advise on the most energy efficient technologies for new construction and renovation building projects.

- Process and Motive Power Systems – the efficiency customers will achieve. Industrial systems staff can improve the operating efficiency of energy consuming processes and electric motor-driven equipment. Through the Performance Optimization Program, Manitoba Hydro specialists can help facilities realize significant cost savings and productivity gains.

- On-site Generation and Recovery – the environment customers will benefit. Biosystems and technology development staff specialize in supporting unique opportunities to convert waste product streams into useful heat and power. Through process integration techniques, industrial specialists can show how existing waste product streams can be used for co-generation or recovered to avoid energy purchases and waste disposal costs.

- Power Quality – the reliability customers demand. Power quality systems staff can advise on the causes of electrical disturbances and benchmark the condition of a facility's electrical distribution system. Through sophisticated measuring and analysis instruments, our specialists can isolate problems and suggest cost-effective mitigation to guard against production downtime and equipment damage and ensure reliable operation of production and energy efficient equipment.

Growing Customer Business Strategically

- Applied Research and Development – opening doors to the future. Manitoba Hydro sponsors R&D projects in partnership with other firms to optimize new and energy efficient applications.

- Process Technology Evaluation – create optimal efficiencies. Manitoba Hydro specializes in identifying and assessing the technical and financial attractiveness of new and innovative applications of technologies in key processes.

- Integrated Manufacturing – the key to sustainable development. Manitoba Hydro specializes in identifying sustainable development opportunities where process by-products can be recovered and utilized to produce value added products; good for the environment and the company's bottom line.

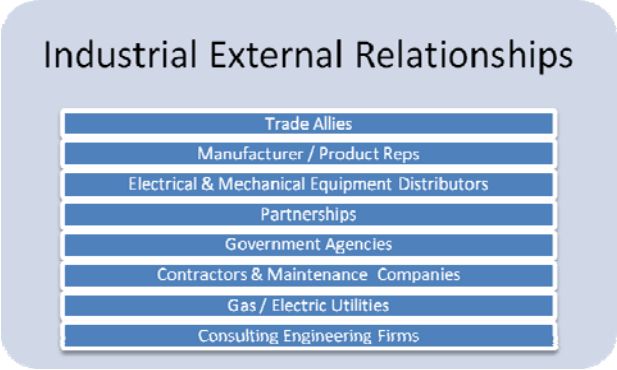
✓ **Integrated Approach to Program Design**

Development of a lean energy approach for the Industrial Power Smart Performance Optimization program enables the identification of efficiency opportunities that enhance the benefits and value available to the customer. A Power Smart lean approach refers to improvement efforts related to energy (electric, natural gas and others), water, wastewater, solid waste and emissions.

The opportunity for an integrated strategy for delivering both natural gas and electric DSM to industrial customers is currently delivering successful results. This is demonstrated through combined customized analysis of electric and gas fuelled technologies and systems with recommendations for both electric and gas incentives for implementation of eligible energy efficient measures and system improvements.

✓ **Collaborative Approach**

Manitoba Hydro also uses a collaborative effort in regards to R&D related to end use electric and gas measures (expanded further in R & D sectors).



✓ **Leveraging Non-Energy Related Benefits**

The cost of electricity does not normally form a major component of an industry's operating costs, and as a result, improvement projects focused solely on electricity do not normally receive the required capital for the project to be implemented. To overcome this market barrier, the scope of the analysis is expanded to include all non-energy benefits of which electricity cost savings is only one of many factors that improves the customer's competitiveness.

✓ **Market Focused**

This market segment includes opportunities in both existing and new customer facilities with industrial processes. The primary end uses with energy efficiency potential in these segments include motor driven systems such as pumps, fans and conveyors, process related systems such as heating (furnaces and boilers), cooling and refrigeration, electrochemical, heat recovery, lighting and both stand alone and integrated energy management control systems.

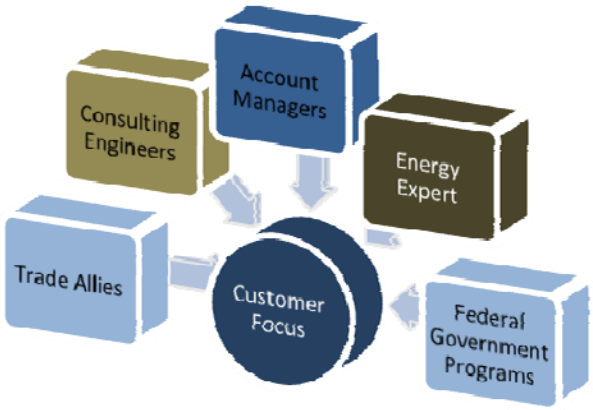
Industrial Power Smart programs are designed to align with the primary business drivers of the industrial customers.

Key opportunities for technology solutions are market orientated in that they emerge from a customer focused effort toward identifying and solving operating and production problems in an energy efficient way and provide the user value in the form of increased efficiency and product competitiveness.

Capital rationing decisions in this sector include energy benefits, but normally are not solely driven by them. Thus, other related production and process benefits must be quantified to enable the creation of financially attractive business cases for project implementation.

Optimal savings for this sector are based upon a "systems approach" that focuses on reducing the end use quantity of air, fluid, heating or cooling required for the process, then addresses the potential improvements in the facility infrastructure (piping, ducting, insulation and building envelope). This approach concludes with enhancements to electrical and mechanical supply equipment and their respective or integrated control systems. This approach can commonly lead to reductions in energy requirement and operating costs of 10 to 50%, depending on the system.

Manitoba Hydro works closely with trade allies and professional associations to support the Industrial Power Smart programs by enhancing their ability to deliver services to industrial customers.



Manitoba Hydro's well respected Customer Relationship Management effort and its existing delivery network of business and technical specialists build customer loyalty and credibility for its energy efficiency efforts and leads to best-in-class performance from the perspective of implementation and delivery efficiency and cost-effectiveness.

Customers' knowledge of Power Smart opportunities and benefits will also be increased through workshops, seminars and personal training by Manitoba Hydro technical experts.

In order to effectively integrate all project benefits into the efficiency project analysis, the customer needs to trust and have confidence in the technical abilities of Manitoba Hydro's technical staff to assist them with their industrial processes. In order to achieve this, technical experts must have both broad and specific knowledge in their area of expertise that is world class. Manitoba Hydro will be positioned as a leading authority in energy efficiency initiatives and will attract, train and retain the best engineers and technologists to gain the confidence and support of customers, market allies and other stakeholders.

In many instances reliability and the quality of power supplied is more important to industrial customers than the efficient use of electricity. Power Quality and short term or long-term reliability issues can lead to significant downtime and lost production and profits.

In order to meet this business driver, a team of Power Quality engineers and technologists provide expert advice for new and existing systems on avoiding electrical production related problems proactively or mitigating these problems after they occur. There is a perception that many of the energy efficient technologies can create power quality and reliability problems and these experts are involved in industrial product testing and evaluation to assist in reducing this problem.

In order to mitigate the production losses associated with power interruptions and in some cases at the insistence of their insurance companies, many power sensitive industrial and commercial customers are installing standby generators. There are numerous operating and maintenance issues associated with reliable operation of these generators. This provides Manitoba Hydro with an opportunity to assist these customers to meet their business driver and at the same time provide demand response benefits to Manitoba Hydro through the use of technology solutions to aggregate the operation of many small generators to achieve a large block of power that can be curtailed from the system by Manitoba Hydro and contribute to Power Smart demand targets.

✓ **Exit Strategy – Codes and Standards**

The exit strategy for the industrial programs is twofold. The primary strategy is that as the market transforms, the incremental cost of the technologies is reduced, and as the non-energy process benefits are better quantified, there is less of an incentive required for the project to be implemented. Following this, Manitoba Hydro will continue to work with Federal, Provincial and local agencies to recommend energy efficiency codes and standards on a proactive basis. Some specific energy efficiency codes and standards under consideration include high efficiency motors, high efficiency pumps and high intensity lighting.

✓ **Promoting Innovation: Research and Development**

Manitoba Hydro Power Smart Industrial staff will continue to partner with other industry and governmental stakeholders for research and development projects that will further efficiency standards in Manitoba such as the bio-pharmaceutical lighting system project and bioenergy CHP technology demonstrations.

Manitoba Hydro will continue to initiate and participate in research and development activities related to industrial energy efficient products and installation methods and utilize the findings of such studies to determine the most effective program to address market needs.

The Canadian Electricity Association, the Canadian Gas Association and Gas Technology Centre, NRCan, and Manitoba Hydro R&D initiatives are the main sponsoring and funding sources. In almost all cases, significant customer or end user group participation is required.

✓ **Leveraging the Corporation's Extensive Infrastructure and Broad Outreach Capabilities**

The future success of Power Smart in the Industrial Sector will rely heavily on the existing infrastructure. Key Account Representatives, Major Account Representatives and Energy Service Advisors will continue to play a key role in promoting Power Smart initiatives and services to their customers. Customer Engineering Services will continue to provide technical support and services to Industrial Power Smart initiatives. Customer Accounting and the Billing Department will provide support for the development and implementation of financing strategies. The Market Forecast department will provide support through end-use information, market demographics and take up rates for potential program offerings. These and other internal resources will continue to support future development and delivery of Industrial Power Smart Programs.

1.8 LOAD MANAGEMENT PORTFOLIO

The **Power Smart Load Management Portfolio** consists of the following program:

Incentive Based Programs

Curtailable Rates Program
Under the Curtailable Rate Program, qualifying customers receive a monthly credit on load (kW) which can be curtailed on notice from Manitoba Hydro.

1.9 LOAD DISPLACEMENT & ALTERNATIVE ENERGY PORTFOLIO

The **Power Smart Load Displacement & Alternative Energy Portfolio** consists of the following programs:

Incentive Based Program

Bioenergy Optimization Program
The Bioenergy Optimization Program encourages customer self-generation through the use of cost-effective biomass to energy conversion systems. The program targets large agricultural and industrial customers with low-cost readily available sources of biomass, continual needs for heat and power and operation capability. As the market for biomass to energy conversion systems mature and customers become more focused on sustainable manufacturing and the impacts of climate change, the target market will be expanded. All customers billed at the General Service rate categories will be eligible for the program; however, only agricultural and industrial customers with readily available low-cost sources of biomass are anticipated to actively participate in the program.

2 ELECTRIC DEMAND SIDE MANAGEMENT

2.1 ELECTRIC DSM TARGETS

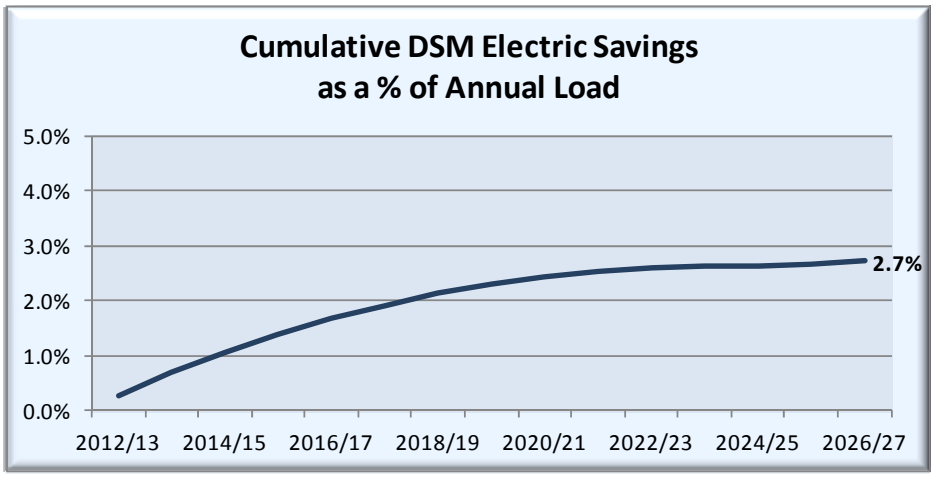
In summary, the 2012/13 Power Smart Plan forecasts achieving capacity savings of 511 MW, energy savings of 1,624 GW.h and a global greenhouse gas emission reduction of 1.1 million tonnes from 2012/13 to 2026/27 with a total utility investment of $337 million.

In combination with savings to date, the 2012/13 Power Smart Plan forecasts achieving capacity savings of 857 MW, energy savings of 3,150 GW.h and a global greenhouse gas emission reduction of 2.1 million tonnes to 2026/27 at a total utility investment of $733 million.

Most notably, the Curtailable Rate Program offers the most significant demand reductions of all DSM programs with approximately 47% of capacity savings, with the commercial sector accounting for approximately an additional 33%.

Moreover, the commercial sector offers the most significant contribution with approximately 54% of electric savings. The industrial sector offers the second largest area for efficiency savings, followed by the residential sector.

This activity represents 2.7% of the estimated load forecast at the benchmark year.



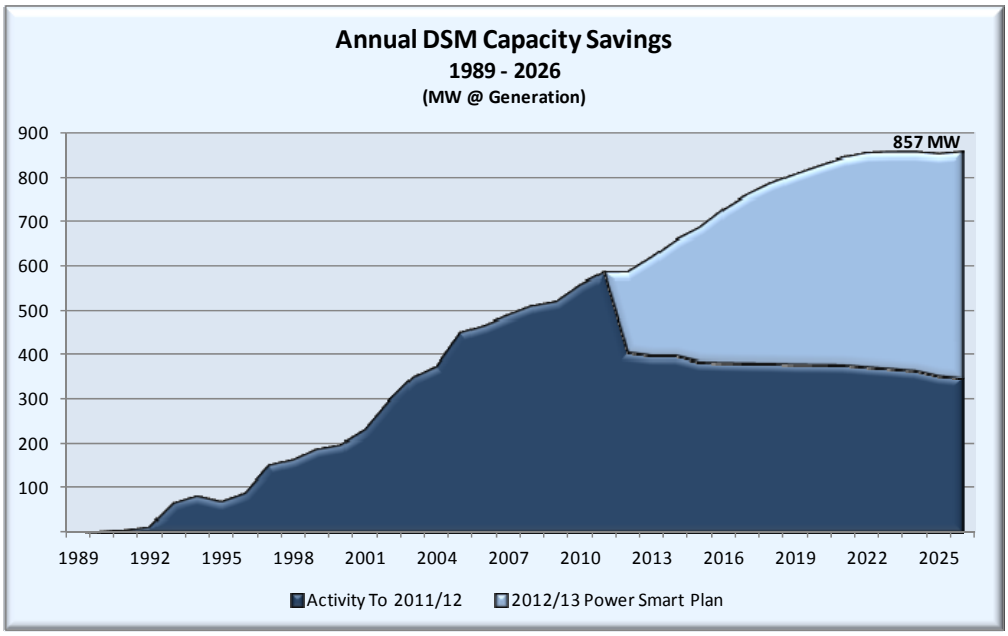
Note:
Total DSM Electric savings per the above graph includes forecasted savings from program impacts and excludes savings from Codes, Standards and Regulations and savings which occurred before 2012.

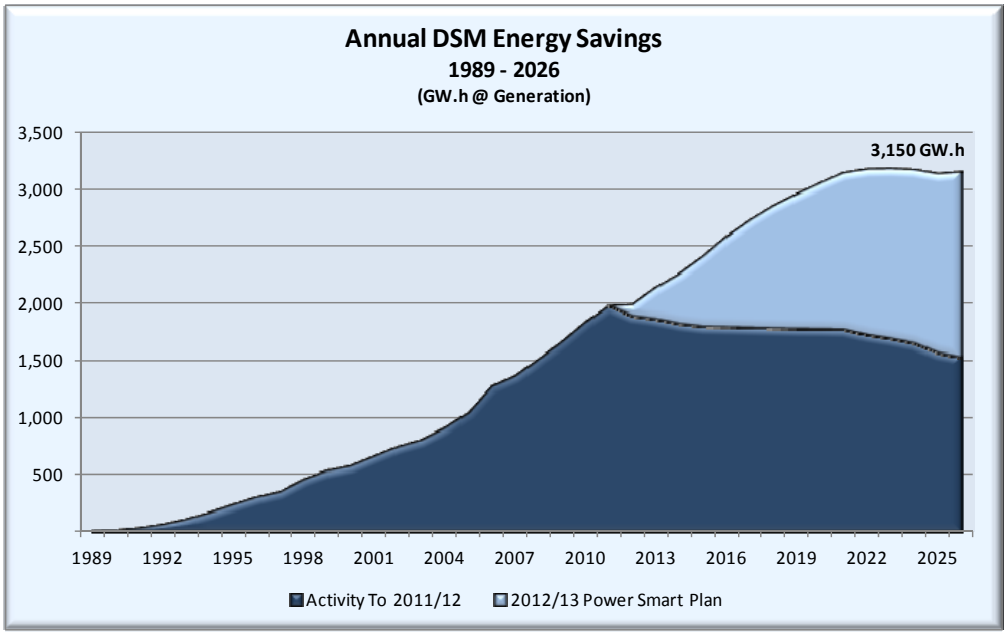
Source of Load Forecast: 2012 Electric Load Forecast

The following table shows detailed savings and costs associated with the Power Smart Plan by sector to 2026.

	Annual Capacity (MW)		Annual Energy (GW.h)		Cumulative Utility Costs (Millions 2012$)	
Residential						
Home Insulation Program	7.4		13.9		$6.2	
Water and Energy Saver Program	1.7		8.7		$2.4	
Lower Income Energy Efficiency Program	2.8		7.0		$1.4	
Refrigerator Retirement Program	0.2		1.7		$4.6	
Residential Programs Total (@ Meter)	12.1	4%	31.3	4%	$14.5	6%
Customer Service Initiatives / Financial Loan Programs						
Power Smart Residential Loan	2.6		5.0		$0.0	
Residential Earth Power Loan	5.6		23.6		$0.0	
Power Smart PAYS Financing	4.5		9.0		$0.0	
Residential CSI / Financial Loan Programs Total (@ Meter)	12.7	4%	37.6	5%	$0.0	0%
Commercial						
Commercial Lighting Program	51.7		187.0		$66.5	
Commercial Custom Measures Program	3.7		14.0		$4.0	
Commercial Windows Program	5.1		13.1		$4.6	
Commercial HVAC Program - Chiller	0.0		7.5		$1.4	
City of Winnipeg Power Smart Agreement	0.0		0.0		$0.0	
Commercial Refrigeration Program	2.9		25.4		$4.4	
Commercial Insulation Program	4.9		12.6		$4.9	
Commercial Earth Power Program	5.8		24.8		$5.2	
New Buildings Program	23.5		88.7		$6.6	
Commercial Building Optimization Program	3.8		19.0		$2.4	
Internal Retrofit Program	0.3		2.0		$1.2	
Commercial Kitchen Appliance Program	0.2		0.7		$0.3	
Commercial Clothes Washers Program	0.4		0.7		$0.1	
Network Energy Management Program	0.0		0.0		$0.5	
CO2 Sensors	0.9		1.3		$0.0	
Commercial Programs Total (@ Meter)	103.1	33%	396.7	54%	$102.1	40%
Customer Service Initiatives / Financial Loan Programs						
Power Smart For Business PAYS Financing	0.6		2.0		$0.0	
Commercial CSI / Financial Loan Programs Total (@ Meter)	0.6	0%	2.0	0%	$0.0	0%
Commercial Market Effects						
Agricultural Heat Pad Program	0.7		5.6		$0.1	
Commercial Parking Lot Controller Program	0.0		2.2		$0.2	
Commercial Rinse & Save Program	0.0		0.0		$0.0	
Commercial Market Effects Total (@ Meter)	0.7	0%	7.9	1%	$0.3	0%
Industrial						
Performance Optimization Program	29.3		187.6		$41.5	
Industrial Programs Total (@ Meter)	29.3	9%	187.6	26%	$41.5	16%
Energy Efficiency - Subtotal (@ Meter)	158.5	51%	663.2	90%	$158.5	61%
Load Management						
Curtailable Rate Program	146.4		0.0		$86.6	
Load Management Programs Total (@ Meter)	146.4	47%	0.0	0%	$86.6	34%
Load Displacement & Alternative Energy						
Bioenergy Optimization Program	8.2		71.9		$13.2	
Load Displacement & Alt. Energy Programs Total (@ Meter)	8.2	3%	71.9	10%	$13.2	5%
Program Impacts Total (@ Meter)	313.1	100%	735.1	100%	$258.2	100%
Codes, Standards and Regulations (@ Meter)	141.2		698.3			
Program Support and Contingency Costs					$79.3	
Power Smart 2012 to 2026 Impacts (@ Meter)	454.3		1,433.5			
Power Smart 2012 to 2026 Impacts (@ Generation)	510.5		1,623.8		$337.5	
Savings Achieved To 2011/12 (@ Meter)	306.2		1,350.5			
Savings Achieved To 2011/12 (@ Generation)	346.1		1,526.5		$395.7	
Grand Total (@ Meter)	760.5		2,784.0			
Grand Total (@ Generation)	856.6		3,150.3		$733.2	

The following charts graphically represent the capacity and energy savings achieved to date and the savings anticipated from future DSM activity for the 2012/13 Power Smart Plan:





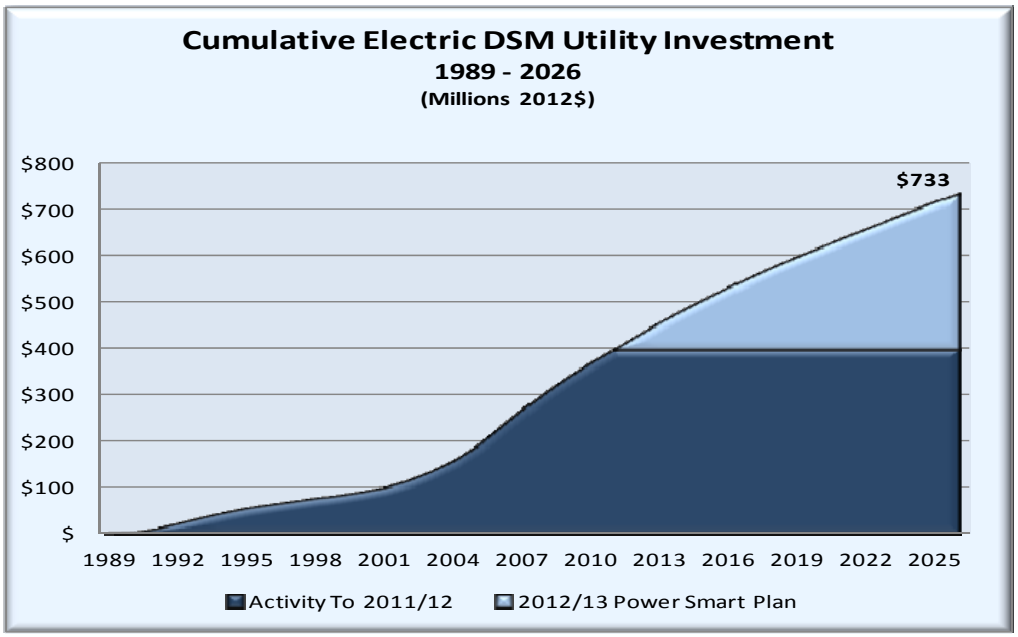
2.2 ELECTRIC DSM UTILITY INVESTMENT

The following table provides the projected annual electric DSM investment and cumulative totals to 2026/27 broken down by market sector and cost basis. It is expected that by 2026/27, a cumulative investment amount of $733 million dollars will have been spent on Power Smart electric programs.

Electric Power Smart Utility Budget
2012/13 - 2026/27
(Millions 2012 $)

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Residential	4.6	4.5	2.2	1.3	1.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Commercial	10.2	9.6	8.6	8.1	8.0	8.0	7.6	6.1	6.0	5.9	5.8	5.7	5.3	4.6	2.8
Industrial	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Rate/Load Management	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	5.8
Load Displacement & Alternative Energy	2.2	2.1	1.8	2.3	1.3	1.3	1.2	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Support and Codes & Standards	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Contingency	0.0	0.8	1.2	1.5	2.0	1.8	1.5	1.5	1.5	1.5	1.5	2.0	2.0	2.0	2.0
Annual Costs	29.4	29.3	26.2	25.5	24.9	23.6	22.6	20.9	19.9	19.7	19.7	20.1	19.7	18.9	17.2
Cumulative Cost, 2012 - 2026	$29.4	$58.7	$84.9	$110.4	$135.3	$158.8	$181.5	$202.3	$222.2	$241.9	$261.6	$281.7	$301.4	$320.3	$337.5
Cumulative Cost, 1989 - 2026	$425.1	$454.5	$480.7	$506.1	$531.0	$554.5	$577.2	$598.1	$617.9	$637.7	$657.3	$677.4	$697.1	$716.0	$733.2

The following graph provides the cumulative electric DSM utility cost for electric DSM from 1989/90 through to 2026/27. Electric expenditures to date comprise 54% of the projected cumulative electricity expenditures for 2026/27.



2.3 ELECTRIC DSM COST EFFECTIVENESS

The following table outlines the cost effectiveness of the electric program offerings provided in the 2012/13 Power Smart Plan.

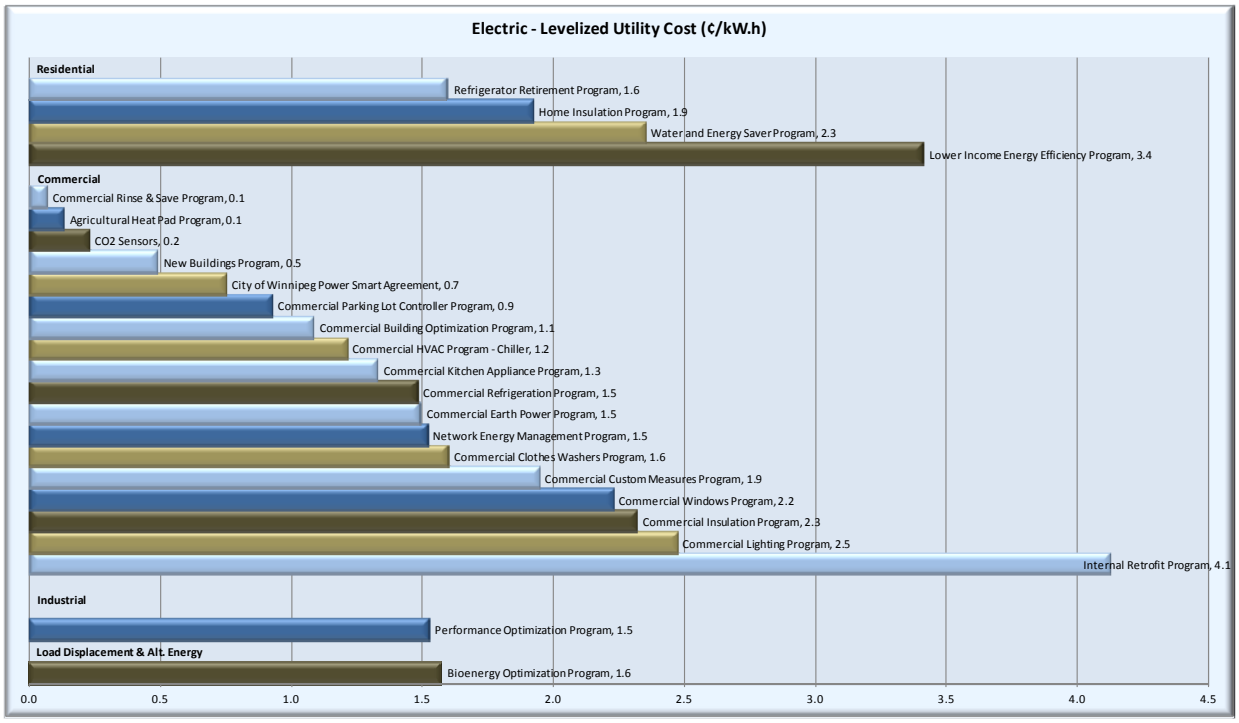
Power Smart Plan Economic Cost Effectiveness Ratios and Levelized Costs
2012/13 - 2041/42

	TRC	RIM	LUC (¢/kW.h)	Customer Payback (years)
Residential				
Home Insulation Program	5.1	1.5	1.9	1.3 *
Water and Energy Saver Program	4.7	0.9	2.3	n/a ^ w
Lower Income Energy Efficiency Program	1.6	1.1	3.4	3.5 ** w
Refrigerator Retirement Program	1.9	0.8	1.6	2.1
Residential Programs Total	3.1	1.1	1.7	
Commercial				
Commercial Lighting Program	2.6	1.0	2.5	3.3
Commercial Custom Measures Program	2.0	1.4	1.9	9.1
Commercial Windows Program	4.5	1.4	2.2	0.9
Commercial HVAC Program - Chiller	3.7	0.9	1.2	1.3
City of Winnipeg Power Smart Agreement	10.6	1.2	0.7	0.1
Commercial Refrigeration Program	2.6	1.1	1.5	3.2
Commercial Insulation Program	3.6	1.3	2.3	1.8 *
Commercial Earth Power Program	1.7	1.3	1.5	9.8 *
New Buildings Program	8.1	1.7	0.5	5.5 c
Commercial Building Optimization Program	5.1	1.3	1.1	1.3
Internal Retrofit Program	1.6	1.6	4.1	n/a ^
Commercial Kitchen Appliance Program	21.3	1.6	1.3	0.7 w
Commercial Clothes Washers Program	3.8	1.3	1.6	4.1 * w
Network Energy Management Program	2.0	1.2	1.5	2.4 *
CO2 Sensors	32.1	2.4	0.2	0.8 *
Commercial Programs Total	3.3	1.2	1.7	
Commercial Market Effects				
Agricultural Heat Pad Program	54.5	1.4	0.1	n/a * ^
Commercial Parking Lot Controller Program	2.8	1.0	0.9	2.5 *
Commercial Rinse & Save Program	492.4	1.9	0.1	n/a * ^ w
Commercial Market Effects Total	9.1	1.3	0.4	
Industrial				
Performance Optimization Program	2.7	1.3	1.5	4.7 *
Industrial Programs Total	2.7	1.3	1.5	
Energy Efficiency - Subtotal	3.1	1.2	1.7	
Load Management				
Curtailable Rate Program	0.0	1.0	n/a	
Load Displacement & Alternative Energy				
Bioenergy Optimization Program	1.7	1.2	1.6	
Overall Portfolio Ratio	2.4	1.1	2.4	

Notes:
** Program assumption includes Spillover, future Market Transformation and/or Participant Re-investment*
*** Includes all Affordable Energy Fund Expenditures*
Excluding apportioned AEF, LIEEP's TRC is 1.9, RIM is 1.4 and LUC is 1.0¢/kw.h
c Program assumption includes savings from Codes & Standards
^ Program with nil or negative net customer costs
w Includes Water Savings Benefits
1) Overall RIM includes Curtailable Rate Program / Overall LUC does not include Curtailable Rate Program
2) Overall portfolio ratios do not include savings due to Customer Service Initiatives / Financial Loan Programs
3) Overall portfolio ratios include support and contingency costs
4) Overall portfolio ratios include Affordable Energy Fund Expenditures
5) Customer Payback tests include first year water savings benefits

The electric Power Smart portfolio has an overall Total Resource Cost (TRC) of 2.4 and Rate Impact Measure (RIM) of 1.1. The overall levelized utility cost for electric programs including support and contingency costs is 2.4 cents per kilowatt-hour.

The following chart compares the Levelized Utility Cost of the electric program offerings provided in the 2012/13 Power Smart Plan.



3 NATURAL GAS DEMAND SIDE MANAGEMENT

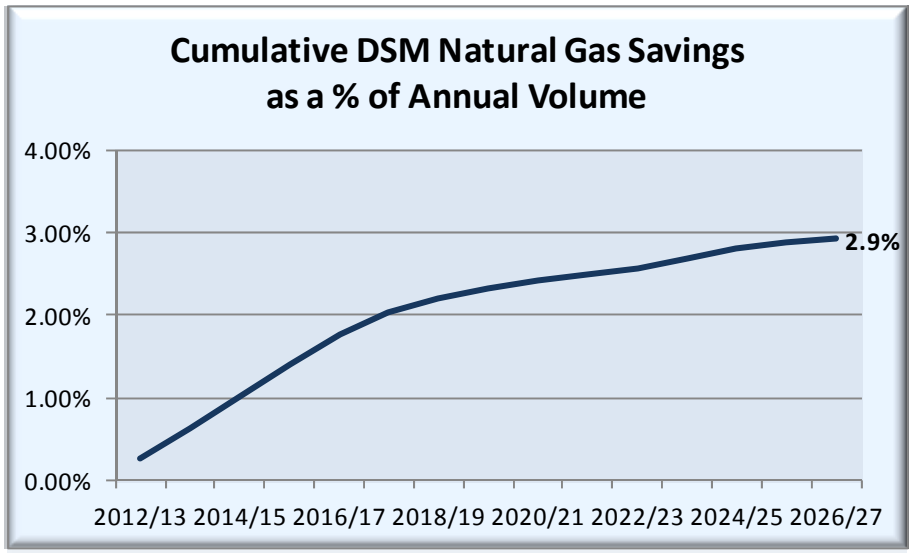
3.1 NATURAL GAS DSM TARGETS

In summary, the 2012/13 Power Smart Plan forecasts achieving natural gas savings of 72 million cubic meters and a global greenhouse gas emission reduction of 0.1 million tonnes from 2011/12 to 2026/27 at a total utility investment of $84 million.

Most notably, the commercial sector offers the most significant contribution with approximately 47% of natural gas savings, with the residential sector accounting for approximately an additional 36%.

In combination with savings to date, the 2012/13 Power Smart Plan forecasts achieving natural gas savings of 136 million cubic meters and global greenhouse gas emission reduction of 0.3 million tonnes to 2026/27 at a total utility investment of $156 million.

This activity represents 2.9% of the estimated load forecast by 2026/27.



Note:
Total DSM Natural Gas savings per the above graph includes savings from program impacts and excludes savings from Codes, Standards and Regulations

Source of Natural Gas Volume Forecast: 2011 Natural Gas Volume Forecast

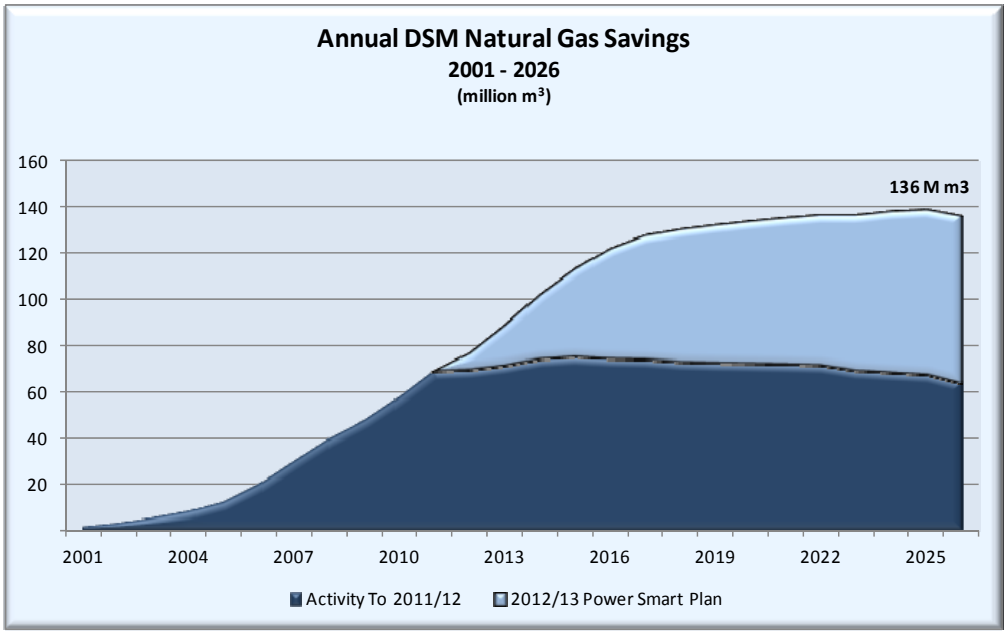
The following table shows detailed savings and costs associated with the Power Smart Plan by sector to 2026:

	Annual Energy (million m3)		Cumulative Utility Costs (Millions 2012$)	
Residential				
Home Insulation Program	4.8		$11.1	
Water and Energy Saver Program	2.4		$2.4	
Lower Income Energy Efficiency Program	3.0		$3.5	
Residential Programs Total (@ Meter)	10.2	18%	$17.0	33%
Customer Service Initiatives / Financial Loan Programs				
Power Smart Residential Loan	5.0		$0.0	
Residential Earth Power Loan	1.8		$0.0	
Power Smart PAYS Financing	3.3		$0.0	
Residential CSI / Financial Loan Programs	10.1	18%	$0.0	0%
Commercial				
Commercial Custom Measures Program	2.0		$2.3	
Commercial Windows Program	2.4		$3.2	
Commercial Insulation Program	6.2		$10.1	
New Buildings Program	6.2		$4.5	
Commercial Building Optimization Program	5.2		$5.6	
Internal Retrofit Program	0.0		$0.1	
Commercial Kitchen Appliance Program	0.2		$0.5	
Commercial Clothes Washers Program	0.0		$0.0	
CO2 Sensors	1.2		$0.5	
Commercial Boiler Program	3.6		$2.2	
Commercial Programs Total (@ Meter)	27.0	47%	$28.8	57%
Customer Service Initiatives / Financial Loan Programs				
Power Smart for Business PAYS Financing	0.1		$0.0	
Commercial CSI / Financial Loan Programs Total	0.1	0%	$0.0	0%
Commercial Market Effects				
Commercial Rinse & Save Program	0.0		$0.0	
Commercial Market Effects Total (@ Meter)	0.0	0%	$0.0	0%
Industrial				
Industrial Natural Gas Optimization Program	8.0		$4.1	
Industrial Programs Total (@ Meter)	8.0	14%	$4.1	8%
Energy Efficiency - Subtotal (@ Meter)	55.4	97%	$49.9	98%
Load Displacement & Alternative Energy				
Bioenergy Optimization Program	1.5		$0.9	
Load Displacement & Alt. Energy Programs Total (@ Meter)	1.5	3%	$0.9	2%
Program Impacts Total (@ Meter)	57.0	100%	$50.7	100%
Interactive Effects	-0.8			
Codes, Standards and Regulations	15.9			
Program Support and Contingency Costs			$32.8	
Power Smart 2012 to 2026 Impacts (@ Meter)	72.1		$83.5	
Savings Achieved To 2011/12	63.6		$72.6	
Grand Total (@ Meter)	135.7		$156.1	

Note:

Natural gas interactive effects have been accounted for in the following: Fridge Recycling Program, Internal Retrofit Program, Network Energy Manager Program, and Commercial Lighting Program. In addition, the Commercial Refrigeration Program results in a net positive natural gas effects, reducing natural gas consumption by 0.69 million cubic meters (m3) by the year 2026/27.

The following chart graphically represents the natural gas savings achieved to date and the savings anticipated from future DSM activity for the 2012/13 Power Smart Plan:



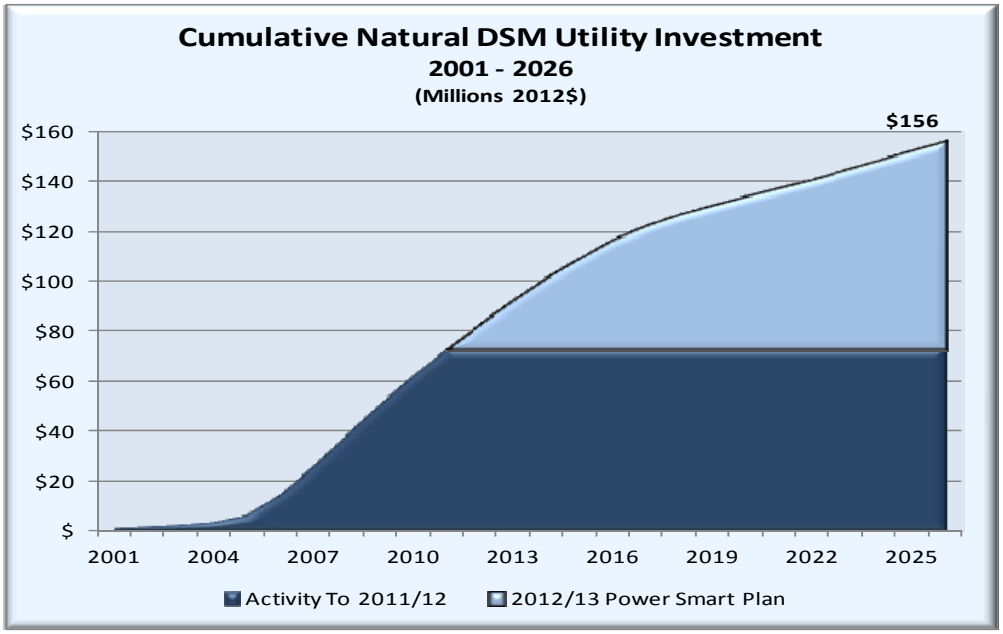
3.2 NATURAL GAS DSM UTILITY INVESTMENT

The following table provides the projected annual natural gas DSM investment and cumulative totals to 2026/27 broken down by market sector and cost basis. It is expected that by 2026/27, a cumulative investment amount of $156 million dollars will have been spent on Power Smart natural gas programs.

Natural Gas Power Smart Utility Budget
2012/13 - 2026/27
(Millions 2012 $)

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Residential	3.3	3.2	3.2	2.4	2.4	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Commercial	4.2	3.4	3.3	2.4	2.4	2.4	2.2	1.3	1.3	1.0	1.0	1.1	1.0	1.0	1.0
Industrial	0.8	0.8	0.6	0.6	0.6	0.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Rate/Load Management	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
Load Displacement & Alternative Energy	0.1	0.2	0.0	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Support and Codes & Standards	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Contingency	0.0	0.3	0.3	0.6	0.6	0.6	0.5	0.5	0.5	0.5	0.5	1.0	1.0	1.0	1.0
Annual Costs	10.0	9.5	9.1	7.9	7.6	5.5	4.6	3.6	3.6	3.3	3.4	3.9	3.8	3.8	3.8
Cumulative Cost, 2012 - 2026	$10.0	$19.5	$28.6	$36.5	$44.1	$49.6	$54.2	$57.9	$61.5	$64.8	$68.2	$72.1	$75.9	$79.7	$83.5
Cumulative Cost, 1989 - 2026	$82.6	$92.1	$101.2	$109.1	$116.7	$122.2	$126.8	$130.5	$134.1	$137.4	$140.8	$144.7	$148.5	$152.3	$156.1

The following graph provides the cumulative natural gas DSM utility cost for natural gas DSM from 2001/02 through to 2026/27. Natural expenditures to date comprise approximately 46% of the projected cumulative electricity expenditures for 2026/27.



3.3 NATURAL GAS DSM COST EFFECTIVENESS

The following table outlines the cost effectiveness of the natural gas program offerings provided in the Power Smart Plan.

Power Smart Plan Economic Cost Effectiveness Ratios and Levelized Costs
2012/13 - 2041/42

	TRC	RIM	LUC (¢/m3)	Customer Payback (years)
Residential				
Home Insulation Program	1.6	0.6	10.4	3.9 *
Water and Energy Saver Program	5.6	0.6	10.0	n/a ^ w
Lower Income Energy Efficiency Program	0.6	0.3	55.2	0.2 ** w
Residential Programs Total	1.3	0.6	10.2	
Commercial				
Commercial Custom Measures Program	1.5	0.7	9.0	5.7
Commercial Windows Program	2.5	0.6	10.3	1.2
Commercial Insulation Program	1.9	0.6	12.0	1.8 *
New Buildings Program	3.1	0.8	5.4	7.5 c
Commercial Building Optimization Program	1.7	0.6	10.9	2.5
Internal Retrofit Program	2.3	2.1	12.7	n/a ^
Commercial Kitchen Appliance Program	8.1	0.7	6.4	1.5 w
Commercial Clothes Washers Program	0.0	0.9	0.0	0.0 * w
CO2 Sensors	2.6	0.8	3.8	3.5 *
Commercial Boiler Program	2.1	0.7	5.5	4.3 c
Commercial Programs Total	2.2	0.7	8.7	
Commercial Market Effects				
Commercial Rinse & Save Program	125.7	0.8	0.7	n/a * ^ w
Commercial Market Effects Total	125.7	0.8	0.7	
Industrial				
Industrial Natural Gas Optimization Program	1.3	0.8	5.1	6.9
Industrial Programs Total	1.3	0.8	5.1	
Energy Efficiency - Subtotal	1.7	0.7	8.6	
Load Displacement & Alternative Energy				
Bioenergy Optimization Program	2.1	0.8	4.8	1.0
Overall Portfolio Ratio (including interactive effects)	1.1	0.6	17.6	

Notes:

** Program assumptions include Spillover, future Market Transformation and/or Participant Re-investment*

*** Includes all Affordable Energy Fund Expenditures / Includes all Furnace Replacement Program expenditures*

Excluding apportioned AEF, without Furnace Replacement Program LIEEP's TRC is 0.8, RIM is 0.6 and LUC is 8.1 ¢/m3

Including apportioned AEF, without Furnace Replacement Program LIEEP's TRC is 0.7, RIM is 0.3 and LUC is 41.8 ¢/m3

Including only the Furnace Replacement Program, LIEEP's TRC is 0.4, RIM is 0.2 and LUC is 111.4 ¢/m3

c Program assumption includes savings from Codes & Standards

^ Program with nil or negative net customer costs

w Includes Water Savings Benefits

1) Overall portfolio ratios do not include savings due to Customer Service Initiatives / Financial Loan Programs

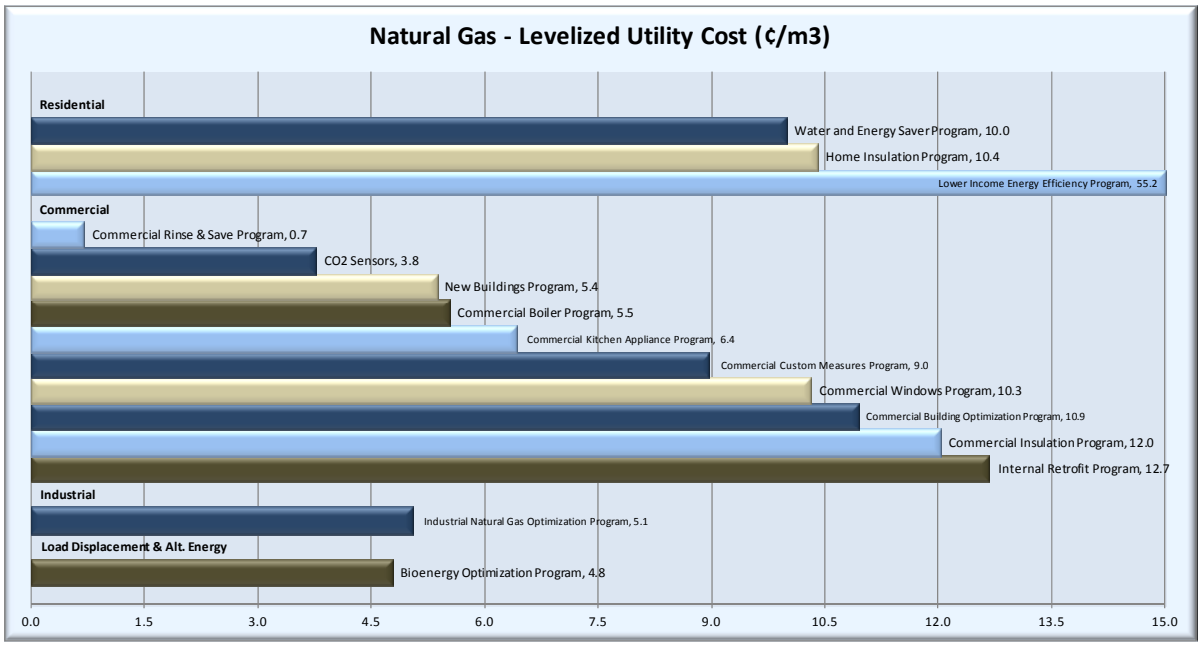
2) Overall portfolio ratios include support and contingency costs

3) Overall portfolio ratios include Affordable Energy Fund Expenditures and Furnace Replacement Program expenditures

4) Customer Payback tests include first year water savings benefits

The natural gas Power Smart portfolio has an overall Total Resource Cost (TRC) of 1.1 and Rate Impact Measure (RIM) of 0.6. The overall levelized utility cost for natural gas programs including support and contingency costs is 17.6 cents per cubic meter.

The following chart compares the Levelized Utility Cost of the natural gas program offerings provided in the 2012/13 Power Smart Plan.



4 COMBINED DEMAND SIDE MANAGEMENT

4.1 PROGRAM DURATION AND CUMULATIVE PARTICIPATION

The following table provides program durations and cumulative participation for incentive based and financial loan programs for the 2012/13 Power Smart Plan.

Program Duration and Cumulative Participation
2012/13 - 2026/27

Programs	Electric	Natural Gas	Electric Program Duration	Natural Gas Program Duration	Program Duration	Cumulative Participation at 2026/27 *
Residential						
Home Insulation Program	√	√	5	5	5	13,252
Water and Energy Saver Program	√	√	3	3	3	29,514
Lower Income Energy Efficiency Program	√	√	5	5	5	9,385
Refrigerator Retirement Program	√		2	-	2	27,200
Power Smart Residential Loan	√	√	-	-	15	82,500 ^
Residential Earth Power Loan	√	√	-	-	15	4,895 ^
Power Smart PAYS Financing	√	√	-	-	15	8,439
Commercial						
Commercial Lighting Program	√		15	-	15	4,551
Commercial Custom Measures Program	√	√	16	16	15	234
Commercial Windows Program	√	√	15	15	15	1,569
Commercial HVAC Program - Chiller	√		6	-	6	20
City of Winnipeg Power Smart Agreement	√		1	-	1	1
Commercial Refrigeration Program	√		13	-	13	803
Commercial Insulation Program	√	√	15	15	15	10,869
Commercial Earth Power Program	√		25	-	25	269
New Buildings Program	√	√	7	7	7	328
Commercial Building Optimization Program	√	√	15	15	15	450
Internal Retrofit Program	√	√	3	1	3	86
Commercial Kitchen Appliance Program	√	√	6	6	6	2,086
Commercial Clothes Washers Program	√		2	-	2	378
Network Energy Management Program	√		2	-	2	167
CO2 Sensors	√	√	7	7	7	3,377
Commercial Boiler Program		√	-	3	3	362
Commercial Parking Lot Controller Program	√		1	-	1	145
Power Smart for Business PAYS Financing	√	√	-	-	15	48
Industrial						
Performance Optimization Program	√		15	-	15	1,245
Industrial Natural Gas Optimization Program		√	-	6	6	80
Load Management						
Curtailable Rate Program	√		30	-	30	90 ^^
Load Displacement & Alternative Energy						
Bioenergy Optimization Program	√	√	8	8	8	62

** Represents cumulative participation based on number of applicants*

^ Represents cumulative number of loans

^^ Participation recurs annually

4.2 COMBINED DSM UTILITY INVESTMENT

The following table provides the combined projected annual and cumulative Power Smart investment to 2026/27 for electric and natural gas DSM portfolios. Annual investment is broken down on a market sector and cost basis. It is expected that by 2026/27 a cumulative investment of $889 million dollars will have been spent on all Power Smart programs.

Combined Power Smart Utilty Budget
2012/13 - 2026/27
(Millions 2012 $)

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27
Residential	7.9	7.7	5.4	3.6	3.6	0.5	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Commercial	14.4	13.0	11.9	10.5	10.4	10.3	9.8	7.4	7.3	6.9	6.8	6.8	6.3	5.5	3.8
Industrial	3.5	3.5	3.4	3.4	3.4	3.4	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
Rate/Load Management	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	5.8
Load Displacement & Alt. Energy	2.4	2.3	1.9	2.5	1.4	1.4	1.3	0.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Support and Codes & Standards	5.5	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
Contingency	0.0	1.1	1.5	2.1	2.6	2.3	2.0	2.0	2.0	2.0	2.0	3.0	3.0	3.0	3.0
Annual Costs	39.4	38.8	35.3	33.3	32.5	29.1	27.2	24.5	23.5	23.1	23.0	24.0	23.5	22.7	21.0
Cumulative Cost, 2012 - 2026	$39.4	$78.2	$113.5	$146.9	$179.4	$208.4	$235.7	$260.2	$283.7	$306.7	$329.8	$353.8	$377.3	$400.0	$421.0
Cumulative Cost, 1989 - 2026	$507.7	$546.6	$581.9	$615.2	$647.7	$676.7	$704.0	$728.5	$752.0	$775.1	$798.1	$822.1	$845.6	$868.4	$889.3

4.3 COMBINED DSM COST EFFECTIVENESS

The following table outlines the cost effectiveness of all program offerings in the Power Smart Plan. The combined electric and natural gas Power Smart portfolio is cost-effective with an overall TRC of 2.0 and SC metric of 2.2.

Combined DSM Cost Effectiveness
2012/13 - 2041/42

	Combined TRC	Combined SC
Residential		
Home Insulation Program	2.6	2.8
Water and Energy Saver Program	5.2	5.7 ^
Lower Income Energy Efficiency Program	0.8	0.9 ** ^
Refrigerator Retirement Program	1.4	1.5 *
Residential Total	2.0	2.2
Commercial		
Commercial Lighting Program	2.6	2.8 *
Commercial Custom Measures Program	1.8	2.0
Commercial Windows Program	3.6	4.0
Commercial HVAC Program - Chiller	3.7	4.1
City of Winnipeg Power Smart Agreement	10.6	11.7
Commercial Refrigeration Program	2.9	3.2 *
Commercial Insulation Program	2.4	2.7
Commercial Earth Power Program	1.7	1.9
New Buildings Program	6.4	7.0 c
Commercial Building Optimization Program	2.7	3.0
Internal Retrofit Program	1.6	1.8 *
Commercial Kitchen Appliance Program	12.7	13.9 ^
Commercial Clothes Washers Program	4.2	4.7 * ^
Network Energy Management Program	1.9	2.1 *
CO2 Sensors	4.1	4.5 [1]
Commercial Boiler Program	2.1	2.3 c
Commercial Total	3.0	3.3
Commercial Market Effects		
Agricultural Heat Pad Program	54.5	59.9
Commercial Parking Lot Controller Program	2.8	3.1
Commercial Rinse & Save Program	175.0	192.5 ^
Commercial Market Effects Total	9.1	10.0
Industrial		
Performance Optimization Program	2.7	2.9
Industrial Natural Gas Optimization Program	1.3	1.4
Industrial Total	2.4	2.6
Energy Efficiency Total	2.7	2.9
Load Management		
Curtailable Rates Program	n/a	n/a
Load Displacement & Alternative Energy		
Bioenergy Optimization Program	1.7	1.9
Overall Benefit Cost Ratio	2.0	2.2

Notes:

** Includes Natural Gas Interactive Effects*

*** Includes all Affordable Energy Fund Expenditures / Includes all Furnace Replacement Program expenditures*

Excluding apportioned AEF, without Furnace Replacement Program, LIEEP's TRC is 1.1 and SC is 1.3

Including apportioned AEF, without Furnace Replacement Program, LIEEP's TRC is 0.9 and SC is 1.0

^ Includes Water Saving Benefits

c Program assumptions includes savings from Codes & Standards

1) Overall benefit/cost ratios do not include Curtailable Rate Program

2) Overall benefit/cost ratios do not include savings due to Customer Service Initiatives / Financial Loan Programs

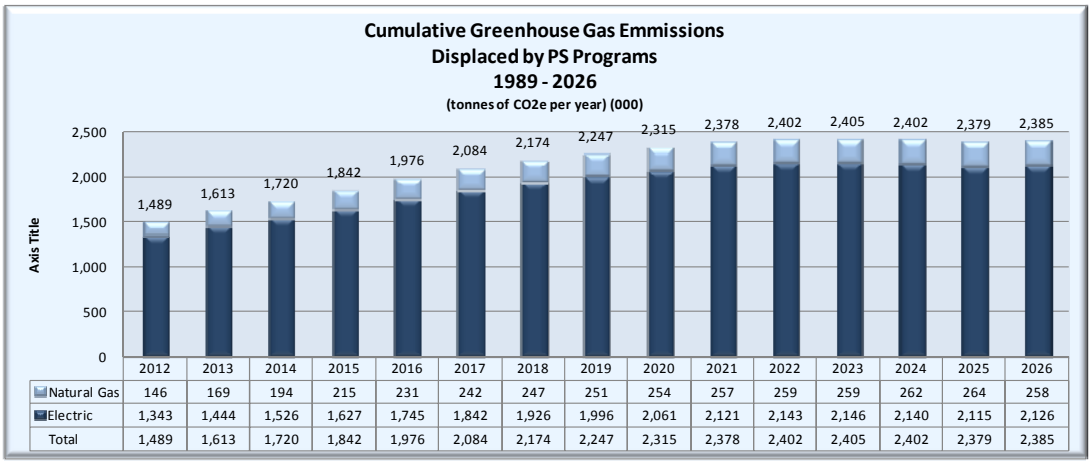
3) Overall benefit/cost ratios include support and contingency costs

4) Overall benefit/cost ratios includes Affordable Energy Fund Expenditures and Furnace Replacement Program expenditures

4.4 COMBINED GLOBAL GREENHOUSE GAS EMISSIONS REDUCTIONS

The following chart and graph depict the aggregate global greenhouse gas emissions reductions resulting from the electricity and natural gas DSM programs outlined in the 2012/13 Power Smart Plan, including greenhouse gas emission reductions resulting from Manitoba Hydro's Power Smart efforts since 1989. Global greenhouse gas emission reductions of 1.2 million tonnes are forecast to be achieved due to energy savings outlined in the Power Smart Plan. Including reductions achieved to date, approximately 2.4 million tonnes are forecast to be realized due to Manitoba Hydro's Power Smart efforts by 2026/27.

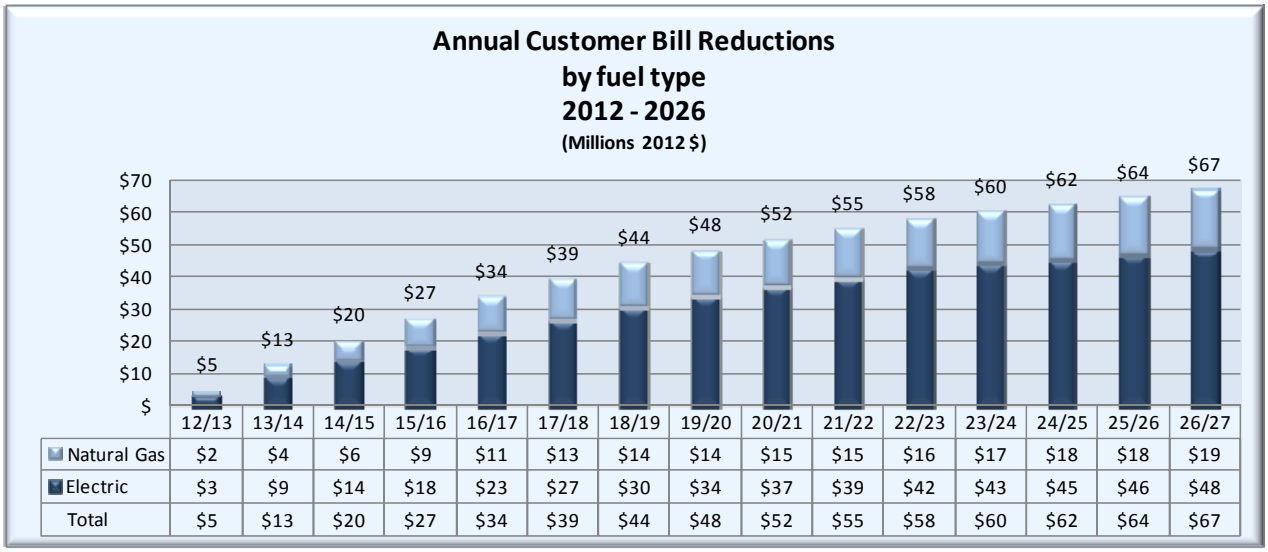
	Annual CO_2 Reductions (Tonnes)
CO_2 Reductions - Electric	1,096,037
CO_2 Reductions - Natural Gas	137,247
2012/13 Power Smart Plan (2012-2026)	1,233,284
CO_2 Reductions Achieved to Date - Electric	1,030,411
CO_2 Reductions Achieved To Date - Natural Gas	120,954
Savings Achieved to 2011/12 (1989-2026)	1,151,365
Total Projected to 2026/27	2,384,649



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Natural Gas	146	169	194	215	231	242	247	251	254	257	259	259	262	264	258
Electric	1,343	1,444	1,526	1,627	1,745	1,842	1,926	1,996	2,061	2,121	2,143	2,146	2,140	2,115	2,126
Total	1,489	1,613	1,720	1,842	1,976	2,084	2,174	2,247	2,315	2,378	2,402	2,405	2,402	2,379	2,385

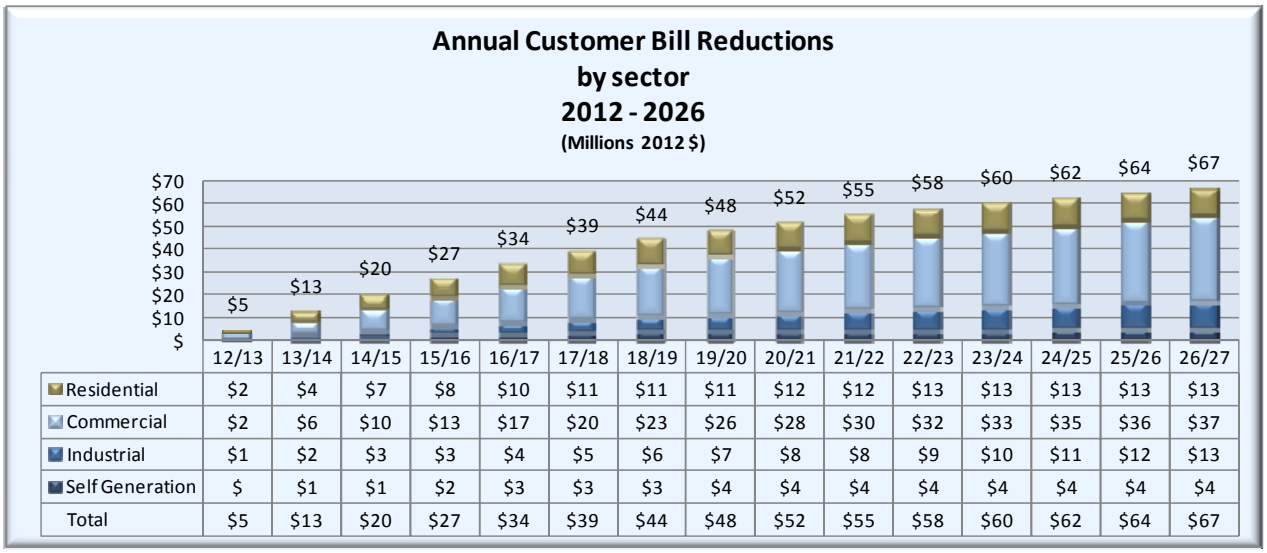
4.5 COMBINED CUSTOMER BILL REDUCTIONS

The following graph depicts customer bill reductions resulting from electric and natural gas programs outlined in the 2012/13 Power Smart Plan. Power Smart programs are expected to save participating customers $67 million dollars in 2026/27 and $648 million cumulatively by 2026.



	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Natural Gas	$2	$4	$6	$9	$11	$13	$14	$14	$15	$15	$16	$17	$18	$18	$19
Electric	$3	$9	$14	$18	$23	$27	$30	$34	$37	$39	$42	$43	$45	$46	$48
Total	$5	$13	$20	$27	$34	$39	$44	$48	$52	$55	$58	$60	$62	$64	$67

The following graph depicts customer bill reductions resulting from electric and natural gas programs outlined in the 2012/13 Power Smart Plan by sector:



	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	21/22	22/23	23/24	24/25	25/26	26/27
Residential	$2	$4	$7	$8	$10	$11	$11	$11	$12	$12	$13	$13	$13	$13	$13
Commercial	$2	$6	$10	$13	$17	$20	$23	$26	$28	$30	$32	$33	$35	$36	$37
Industrial	$1	$2	$3	$3	$4	$5	$6	$7	$8	$8	$9	$10	$11	$12	$13
Self Generation	$	$1	$1	$2	$3	$3	$3	$4	$4	$4	$4	$4	$4	$4	$4
Total	$5	$13	$20	$27	$34	$39	$44	$48	$52	$55	$58	$60	$62	$64	$67

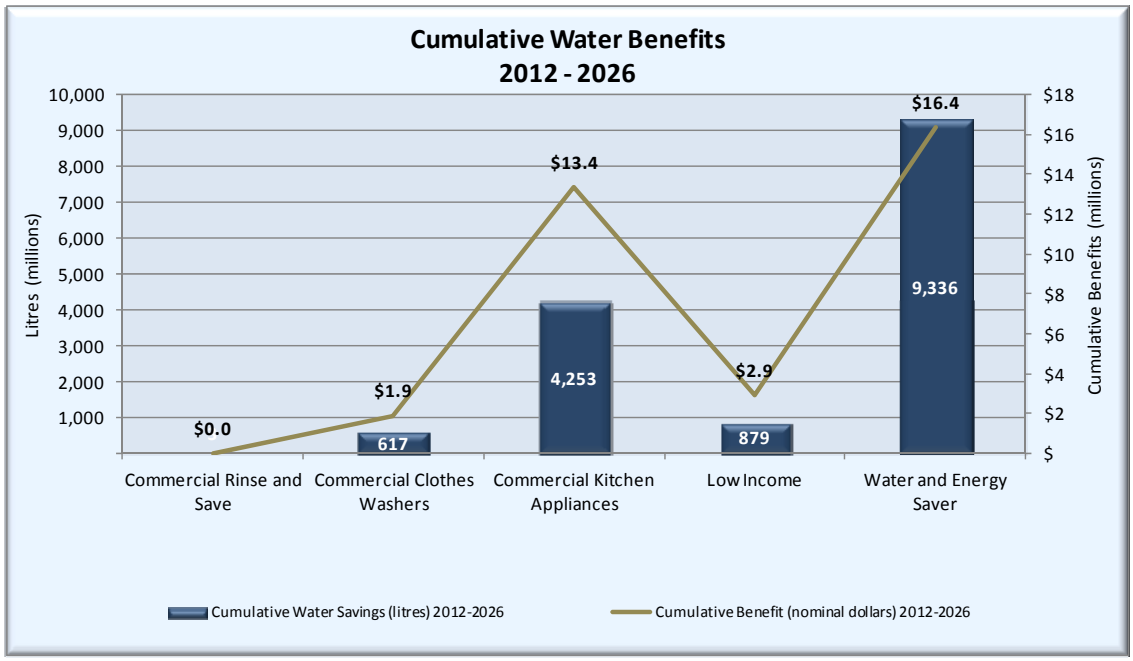
When combined with bill reductions to date, Power Smart programs are expected to save participating customers $132 million in 2026/27 and over $2.5 billion dollars cumulatively by 2026/27.

4.6 COMBINED ADDITIONAL NON-ENERGY BENEFITS

As part of the 2012/13 Power Smart Plan, the following residential and commercial programs are expected to capture additional water saving benefits:

- Water and Energy Saver Program
- Lower Income Energy Efficiency Program
- Commercial Clothes Washer Program
- Commercial Rinse and Save Program
- Commercial Kitchen Appliance Program

The following graph depicts cumulative water savings in litres and cumulative customer dollar savings from each of the above programs. It is estimated that savings of approximately 15 billion liters of water and $34 million in bill savings will be achieved from 2012/13 to 2026/27.



When combined with savings to date, Power Smart programs are expected to save approximately 32 billion liters of water and $108 million by 2026/27.

5 ENERGY EFFICIENT CODES & STANDARDS

Canadian and U.S. electric utilities, including Manitoba Hydro, have been engaged in DSM activities for many years. In addition to utility specific DSM programs, Manitoba Hydro's strategy to affect change in codes and standards involves being an aggressive and active participant and, in many cases, a driving force on a number of provincial and national energy efficiency codes and standards committees. The focus of Manitoba Hydro's efforts on these committees is to advance the progress of product efficiency improvements through the development of minimum energy performance standards and to develop energy efficient codes and regulations.

Manitoba Hydro annually prepares a forecast of the expected influence of codes and standards, and since 1995 this forecast has been used to adjust Manitoba Hydro's system load forecast.

5.1 ENERGY SAVINGS FROM CODES & STANDARDS

In many markets, the most effective and permanent form of market transformation for energy efficient technologies and practices is the adoption of energy efficient codes and standards as it ensures that customers do not revert to less efficient technologies/practices once the incentives and/or promotional activities are discontinued. Consequently, the process of achieving these changes is complex and lengthy as it involves many stakeholders, varying environmental and market conditions and market acceptance to ensure successful implementation.

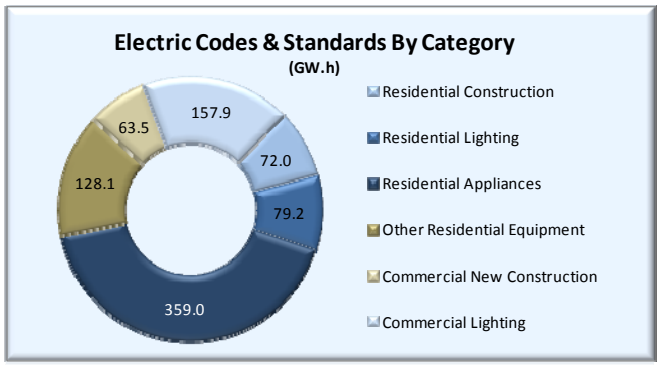
As a result of efforts to achieve energy savings through Energy Efficient Codes and Standards initiatives, the 2012/13 Power Smart Plan forecasts achieving capacity savings of 188.9 MW, energy savings of 859.6 GW.h and 20.7 million cubic meters of natural gas annually by 2026/27. As a result of these savings, a greenhouse gas emissions reduction of 0.6 million tonnes is expected by 2026/27.

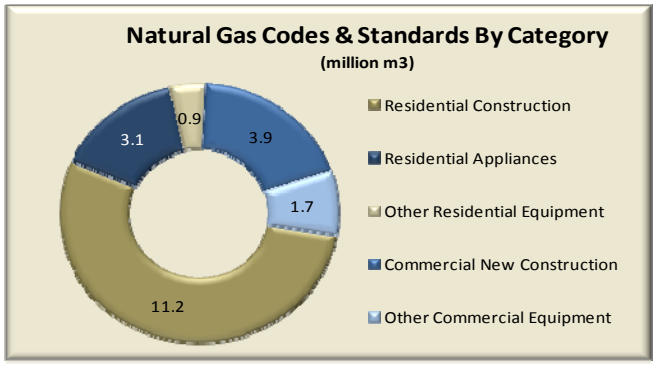
The following table and charts provide a summary of the planned energy savings in 2026/27 from codes and standards. Future DSM plans will provide updated forecasts of savings from codes and standards based on new information.

Energy Savings from Codes & Standards
(2026/27)

Code Category	Components	Energy and Demand Savings Winter MW (2026/27)	Energy and Demand Savings Annual GW.h (2026/27)	Natural Gas Annual Millions m3 (2026/27)	CO2 Reductions Annual Tonnes (2026/27)
Residential Construction	Insulation, Windows, Pilot Light Gas Fire Place, Furnance, Heat Recovery Ventilation, Showerhead	38.5	72.0	11.2	69,840
Residential Lighting	General Service Lamps	18.7	79.2	0.0	53,450
Residential Appliances	Dishwashers, Clothes Washers, Clothes Dryers, Refrigerators, Freezers, Ranges, Stoves, Cooktops	53.8	359.0	3.1	248,149
Other Residential Equipment	Electric Hot Water Tank, Central Air Conditioning, Residential Furnace	6.2	128.1	0.9	88,121
Commercial New Construction	Various Building Code Amendments	28.0	63.5	3.9	50,303
Commercial Lighting	Fluorescent Lighting, Exit Signs, Fluorescent Lamp Ballasts	43.7	157.9	0.0	106,556
Other Commercial Equipment	Commercial Furnace, Boiler and Hot Water Tanks	0.0	0.0	1.7	3,187
Total @ Generation		188.9	859.6	20.7	619,606

* Totals per above include savings attributed to specific Power Smart programs and thus differ from Codes and Standards savings reported in Appendices A.1, A.3 and C.1





5.2 STATUS OF CODES AND STANDARDS

The following table summarizes the status of the changes to codes and standards included in the 2012/13 Power Smart Plan, including actual or expected dates.

For electricity, changes that account for 84% of total energy savings have been enacted, 9% have been announced and 7% are planned.

For natural gas, changes that account for 75% of total energy savings have been enacted, 6% have been announced and 19% are planned.

Status of Changes to Codes and Standards
(2026/27)

Code Category	Components	Energy Annual GW.h (2026/27)	Natural Gas Annual Millions m3 (2026/27)	Level of Government	Expected Effective Date Enacted	Announced	Planned
Residential Construction	Building Code - Insulation	15.7	1.3	MB	2008		
Residential Construction	Building Code - Various measures	56.3	9.8	MB	2010		
Residential Lighting	General Service Lamps	79.2	0.0	Federal		2014	
Residential Appliances	Various appliances	359.0	3.1	Federal			
Other Residential Equipment	Electric Hot Water Tank	31.6	0.0	Federal	2004		
Other Residential Equipment	Central Air Conditioning	96.5	0.0	Federal	2006		
Other Residential Equipment	Residential Furnace	0.0	0.9	Federal / MB	2009		
Commercial New Construction	Building Code	63.5	3.9	MB			2013
Commercial Lighting	Fluorescent Lighting	4.2	0.0	Federal	1996		
Commercial Lighting	Exit Signs	1.8	0.0	Federal	2004		
Commercial Lighting	Fluorescent lamp ballasts (New / Reno)	151.9	0.0	Federal	2006 / 2010		
Other Commercial Equipment	Commercial Furnace	0.0	0.4	Federal / MB	2009		
Other Commercial Equipment	Commercial Boilers	0.0	0.9	Federal / MB		2015	
Other Commercial Equipment	Hot Water Tanks	0.0	0.4	Federal / MB		2016	
Total (GW.h)		859.6			716.9	79.2	63.5
					84%	9%	7%
Total (million m3)			20.7		15.5	1.2	3.9
					75%	6%	19%

5.3 CODE, STANDARD & REGULATION DESCRIPTIONS

The following section describes each of the codes and standards listed in the Summary Table noted in Section 5.2.

Residential Construction

Building Code
Manitoba Building Code, amendment (PROVINCIAL)
Regulation 4/2008
Registered: January 11, 2008
Effective date: October 1, 2008

Manitoba Hydro has been offering the Power Smart New Home program to customers across the province since 2004. The New Home program promoted and offered incentives to customers for the installation of energy efficient technologies and building practices within the New Home construction industry. Manitoba Hydro worked closely with industry stakeholders like the Manitoba Home Builders' Association when developing requirements for the program. Specifically, the Power Smart New Home program has required and been promoting a minimum requirement for R20 insulation in the foundation walls of new homes since 2004.

Changes to Table 9.25.5.2. (Minimum Thermal Resistance for the Building Envelope) of the Manitoba Building Code (Regulation 127/2006) came into effect on October1, 2008. The changes related to the minimum requirement for insulation R-value for the interior and exterior foundation walls of new homes. The code change increased the minimum required insulation value from R12 to R20.

Building Code
Manitoba Building Code, amendment (PROVINCIAL)
Regulation 142/2010
Registered: October 4, 2010
Effective date: December 1, 2010

Manitoba Hydro has promoted energy efficient technologies and building practices within the residential new construction segment through delivery of the Power Smart New Home Program. When developing program requirements, Manitoba Hydro worked closely with industry stakeholders like the Manitoba Home Builders Association.

Through the delivery of the Power Smart Gold Home offering, Manitoba Hydro planned to aid the advancement of future building code by promoting and offering incentives to customers to build their home with Power Smart recommended technologies and construction practices. The Gold standard announced in 2007 required the use of heat recovery ventilators (HRV), 94 % AFUE furnaces, electronic ignition for natural gas fireplaces, R50 attic insulation, water efficient fixtures and many other building envelope improvements.

Effective December 1st, 2010, Manitoba implemented changes to the building and plumbing codes that increased energy and water efficiencies. These changes were the result of extensive consultations by the Office of the Fire Commissioner involving new homebuilders, contractors and technical experts. The new efficiencies incorporated into new construction and homes undergoing extensive renovations included:

- specifying minimum energy-efficiency requirements for windows,
- eliminating the pilot light in gas fireplaces,
- increasing the required level of attic insulation to R50,
- requiring a minimum 94 per cent fuel-efficiency rating for furnaces,
- specifying a mid-efficient heat-recovery ventilator, and
- introducing energy-modeling software that will allow builders to model alternatives to the code requirements.
- Requiring a maximum flow rate for primary showerheads to 1.75 GPM

Through its close working relations with key industry stakeholders and the Power Smart New Home Program offering, Manitoba Hydro succeeded in advancing these changes to the Manitoba Building code. In fact, a majority of the technologies adopted by the Manitoba Building Code for the December 1, 2010 update were part of the aforementioned Power Smart Gold Home standard requirements. Without the program providing information, education, training, and incentives for these technologies and building practices, the industry would have been less likely to adopt these technologies and transform the market. The program created demand for these technologies, provided builders an opportunity to gain experience using them, and provided trades and contractors training opportunities to advance their expertise and knowledge of the technologies.

Residential Lighting

General Service Lamps
National Resources Canada (FEDERAL)
Amendment 10 to Energy Efficiency Regulations
Published: December 24, 2008 (Canada Gazette Part II)
Effective date(s): January 1st, 2012 - 75 to 100 watt equivalent lamps
December 31st, 2012 - 40 to 60 watt equivalent lamps

The Government of Canada announced in Amendment 10 to the Energy Efficiency Regulations, published on December 24, 2008, that they would introduce Minimum Energy Performance Standards (MEPS) for general service lamps in 2012. The consequent Regulations came into force in December 2008 and applied to 100 and 75 W bulbs manufactured on or after January 1, 2012, and to 60 and 40 W bulbs manufactured on or after December 31, 2012. The Regulations prohibit the importation and interprovincial shipment of non-compliant products. The Regulations provide for a number of alternatives to inefficient bulbs. Where no alternatives exist, exemptions are made.

Proposed Extended Effective Date

Currently, a delay in the date for compliance with Canada's efficiency standards for general service lighting for 100/75/60/ 40 W light bulbs (general service lamps) is required in order to strengthen communication activities, to allow for technology innovations and to consider the concerns expressed about the availability of compliant technologies and perceived health and mercury issues, including safe disposal for compact fluorescent lamps (CFLs).

The proposed amendment would delay the completion dates for general service lighting currently prescribed in the Energy Efficiency Regulations (the Regulations) by two years to January 1, 2014, for 100/75 W bulbs and to December 31, 2014, for 60/40 W bulbs.

The Residential Lighting program will continue to interact with the groups/agencies involved with regulating Canada's Minimum Energy Performance Standards (MEPS) for general service lighting forecasted. Manitoba Hydro will continue to actively participate on the Strategic Lighting Initiatives Committee (SLIC) and the Canadian Lighting Industry Committee (CLIC).

In the area of Residential Lighting, Manitoba Hydro estimates that the regulation will realize electric savings of 18.7 MW and 79.2 GW.h by 2026/27.

Residential Appliances

Manitoba Hydro is a key player on the Canadian Standards Association's Strategic Steering Committee on Performance, Energy Efficiency and Renewables (SCOPEER). This committee is responsible for changes to provincial and national performance standards and legislation which have resulted in the improvement of energy utilization of numerous appliances such as dishwashers, clothes washers & dryers, refrigerators and freezers, and ranges/stoves/cooktops.

In the area of Residential Appliances, Manitoba Hydro estimates that changes will realize electric savings of 53.8 MW and 359.0 GW.h and natural gas savings of 3.1 million cubic meters by 2026/27.

Other Residential Equipment

Hot Water Tank Standby Losses
National Resources Canada (FEDERAL)
Amendment 8 to Energy Efficiency Regulations
Test Standard: CAN/CSA-C191-00
Published: September 22, 2004 (Canada Gazette Part II)
Effective date(s): July 1, 2004

Standby heat loss is the heat lost and energy wasted by heating water and storing it in a tank such as the case with traditional tank hot water heaters. That is, heat leaches from the tank to the surrounding air, causing the heater to heat up the water again Storage water heater models with heavily insulated tanks can significantly reduce heat loss.

In 2004, the CSA published a standard (C191-00) which specified requirements related to delivery, minimum standby performance, heater element ratings, and marking of electric storage tank water heaters. With respect to electric water heaters, the changes raised the minimum efficiency, through a 26W reduction in allowable standby loss across tank sizes, which resulted in annual energy savings of approximately 217 kW.h per tank. For standards, standby heat loss savings are based on the water heated for use by dishwashers and clothes washers.

Central Air Conditioning
National Resources Canada (FEDERAL)
Amendment 9 to Energy Efficiency Regulations
Test Standard: CAN/CSA-C656-05
Published: November 15, 2006 (Canada Gazette Part II)
Effective date(s): November 15, 2006

In November 2006, the CSA published a standard (C656-05) which specified mandatory MEPS applied to permanently installed 'air-source' air-conditioner and heat pumps. Equipment types include air conditioners and heat pumps that are single package and split system, single and three-phase, with rated capacity of less than 19 kW (65,000 Btu/h). For air conditioners, a minimum SEER rating of 13 was mandated.

Manitoba Hydro provides a fixed interest finance plan that may be used for renovations including central air, mid-efficient natural gas/electric furnaces and water heaters, direct vent natural gas fireplaces, security lights and fixtures under the Energy Finance Plan. Pre 2005, a minimum SEER rating of 10 for Air Conditioners was required for eligibility for financing under the plan. In order to comply with the forthcoming national standard, Manitoba Hydro raised the minimum SEER to 13 for eligibility of financing in October, 2005; approximately one year earlier.

Residential High Efficiency Furnace
National Resources Canada (FEDERAL)
Amendment 10 to Energy Efficiency Regulations
Published: December 24, 2008 (Canada Gazette Part II)
Effective date: December 31, 2009

On December 12, 2008 the Federal Government amended the Energy Act to require increased efficiency requirements for replacement gas (natural gas and propane) furnaces and boilers. Effective December 31, 2009 replacement furnaces up to 225 000 Btu/h sold in Canada are required to have a minimum AFUE of 90%.

Manitoba Hydro played a material role in the amendment of the Federal Energy Act. Manitoba Hydro staff assisted the Federal Government by providing technical and market data regarding the heating market in Manitoba and comments to the proposed Amendment during the consultation process. Power Smart Programs such as the Residential Loan and the High Efficiency Furnace and Boiler Rebate influenced the Manitoba market to the point that 80% of all equipment installed in 2009 was high efficiency products, thus making the Amendment acceptable to the industry and to consumers.

The Energy Act (PROVINCIAL)
Regulation 181/2009
Published: November 12, 2009
Effective date: December 30, 2009

On November 12, 2009 the Manitoba Government passed a regulation under the Energy Act to require increased efficiency requirements for replacement gas (natural gas and propane) furnaces and boilers. Effective December 30, 2009 replacement furnaces up to 225 000 Btu/h sold in Manitoba are required to have a minimum AFUE of 92%.

Manitoba Hydro played a major role in the development of the Provincial Regulation. Manitoba Hydro staff assisted the Province by providing technical and market data regarding the heating market, hosting an industry consultation with contractors and other interested parties, preparing a formal market impact study, and providing general guidance to regulatory staff. Power Smart Programs such as the Residential Loan and the High Efficiency Furnace and Boiler Rebate influenced the market to the point that 80% of all equipment installed in 2009 was high efficiency products, thus making regulation acceptable to the industry.

In the area of Other Residential Equipment, Manitoba Hydro estimates changes will realize electric savings of 6.2 MW and 128.1 GW.h and natural gas savings of 0.9 million cubic meters by 2026/27.

Commercial New Construction

Building Code

The national commitment to update the 1997 NECB was initiated in Manitoba by the Energy Code Advisory Committee (ECAC) which was led by Manitoba Hydro. Manitoba Hydro also chaired the national Building Energy Code Collaborative (BECC) which was formed in response to the recommendations provided by ECAC. As a result of the work done by BECC, formal support was provided by jurisdictions across Canada to undertake the work to update the 1997 NECB and a national working group was formed to conduct the detailed work for updating the code. Although Manitoba's Minister of Labour provided written support signaling Manitoba's intention to adopt the document once published, the Province still moved forward with their energy strategy and convened a sub-committee of the Building Standards Board of Manitoba to recommend Manitoba based energy and water efficiency recommendations that could be implemented in advance of the release of the NECB.

In January 2011, the energy efficiency amendments to the Manitoba building code were developed and approved by the Building Standards Board of Manitoba and the Minister of Labour. However, with the NECB already through its public consultation phase and with a targeted release date of Fall 2011, it was decided to hold back on regulating the specific Manitoba amendments and review and implement the NECB. The sub-committee that developed the Manitoba amendments has been reconvened in 2012 with the task of reviewing the NECB and determining its applicability to the Manitoba market. Once again, Manitoba Hydro will have a key role with several Power Smart staff contributing to this process. The sub-committee will be aiming for a recommendation that will be formalized through regulation to meet an early 2013 enforcement date.

Manitoba Hydro staff have contributed to the national process and had Customer Engineering Services staff formally attend regular code development meetings to ensure Manitoba Hydro objectives were met. Manitoba Hydro staff were also members of the Manitoba Building Standards Board Sub-Committee on Energy and Water Efficiency which was responsible for recommending that the Province adopt the 2011 NECB and for creating additional recommendations specific to Manitoba that would be incorporated as amendments.

In the area of Commercial New Construction, Manitoba Hydro estimates changes will realize electric savings of 28.0 MW and 63.5 GW.h and natural gas savings of 3.9 million cubic meters by 2026/27.

Commercial Lighting

Since 1992, Manitoba Hydro has been actively promoting energy efficient lighting technologies for commercial applications. Activities involved in developing lighting standards include:

- In collaboration with other utilities, identify necessary research
- Work with Canadian Electrical Association
- Liaise with manufacturers to encourage the development and improvement of energy efficient lighting
- Product testing
- Liaise with National Research Council
- Participation on the CSA Standards Setting Committee
- Participation on the Canadian Lighting Industry Collaborative

<u>T12 Fluorescent Lighting</u>
National Resources Canada (FEDERAL)
Amendment to Energy Efficiency Regulations
Effective date: 1996

Manitoba Hydro's involvement in the area of Commercial Lighting supported the Federal Government's efforts to implement efficiency standards for T12 fluorescent lighting systems in April 1996 under the National Energy Efficiency Act. Under these new regulations, standard fluorescent T12 lamps are now non-complying and only reduced energy and high performance versions can be manufactured and sold in Canada (e.g. the previous standard 40-watt T12 lamp is now replaced with a new 34-watt T12 lamp).

<u>Exit Signs</u>
National Resources Canada (FEDERAL)
Amendment 8 to Energy Efficiency Regulations
Test Standard: CAN/CSA-C860-01
Published: September 22, 2004 (Canada Gazette Part II)
Effective date: November 1, 2004

In September of 2004, Natural Resources Canada's (NRCan's) Office of Energy Efficiency (OEE) amended Canada's Energy Efficiency Regulations (the Regulations) in order to strengthen the minimum energy performance standard for internally lighted exit signs with the publication of Amendment 8 in Canada Gazette Part II. This standard contains voluntary minimum performance standards of 22 watts for signs 120 V or less, and 27 watts for signs greater than 120 V. These levels were harmonized with the National Building Code of Canada. The standard also addresses the visibility performance of the exit sign. To meet these standards, typically requires that LED technology be employed. In the area of LED lighting, the program supported these minimum efficiency levels for new exit signs with signs set at a level that only LED exit signs could meet.

Fluorescent lamp ballasts
National Resources Canada (FEDERAL)
Amendment 9 to Energy Efficiency Regulations
Test Standard: CAN/CSA-C654-M91
Published: November 15, 2006 (Canada Gazette Part II)
Effective date(s): November 15th, 2006 (New Construction Market)
April 1st, 2010 (Renovation Market)

In November of 2006, Natural Resources Canada's (NRCan's) Office of Energy Efficiency (OEE) amended Canada's Energy Efficiency Regulations (the Regulations) in order to strengthen the minimum energy performance standard for florescent lamp ballasts with the publication of Amendment 9 in Canada Gazette Part II. Manitoba Hydro's lighting initiative helped support this Federal code change that required fluorescent lamp ballasts meet a prescribed minimum energy performance standard in the new construction market in 2006 and the renovation market in 2010.

In the area of Commercial Lighting, Manitoba Hydro estimates that the regulations will realize electric savings of 43.7 MW and 157.9 GW.h by 2026/27.

Other Commercial Equipment

Commercial High Efficiency Furnace
National Resources Canada (FEDERAL)
Amendment 10 to Energy Efficiency Regulations
Published: December 24, 2008 (Canada Gazette Part II)
Effective date: December 31, 2009

On December 12, 2008 the Federal Government amended the Energy Act to require increased efficiency requirements for replacement gas (natural gas and propane) furnaces and boilers. Effective December 31, 2009 replacement furnaces up to 225 000 Btu/h sold in Canada are required to have a minimum AFUE of 90%.

Manitoba Hydro played a material role in the amendment of Canada's Energy Efficiency Act. Manitoba Hydro staff assisted the Federal Government by providing technical and market data regarding the furnace market in Manitoba and comments to the proposed Amendment during the consultation process. Power Smart programs such as the Power Smart Residential Loan, the Residential High Efficiency Furnace and Boiler Rebate, and the Commercial HVAC Program - High Efficiency Furnace incentive all influenced market adoption; increasing market penetration of high efficiency furnaces in Manitoba commercial buildings from the pre-program average of 30% to 75% at program termination. Manitoba Hydro's involvement has expedited market transformation and thus facilitated the adoption of the federal efficiency regulation.

The Energy Act (PROVINCIAL)
Regulation 181/2009
Published: November 12, 2009
Effective date: December 30, 2009

On November 12, 2009 the Manitoba Government passed a regulation under the Energy Act to require increased efficiency requirements for replacement gas (natural gas and propane) furnaces and boilers. Effective December 30, 2009 replacement furnaces up to 225 000 Btu/h sold in Manitoba are required to have a minimum AFUE of 92%.

Manitoba Hydro played a material role in the development of the provincial efficiency regulation. Manitoba Hydro staff assisted the Manitoba Government by providing technical and market data, hosting an industry consultation with contractors and other interested parties, preparing a formal market impact study, and providing general guidance to regulatory staff. Power Smart programs such as the Residential Loan, the Residential High Efficiency Furnace and Boiler Rebate, and the Commercial HVAC Program - High Efficiency Furnace incentive all helped to expedite market adoption of high efficiency furnaces in Manitoba commercial buildings from the pre-program average of 30% to 75% at program termination. Manitoba Hydro's active involvement had expedited market transformation, and thus facilitated the adoption of the provincial efficiency regulation.

<u>Commercial Boilers</u>
National Resources Canada (FEDERAL)
Bulletin published: August 2010
Test Standard: HI BTS 2000, Rev 06.07 Method to Determine Efficiency of Commercial Space Heating Boilers
Proposed Effective date(s): March, 2015 (90% Min Efficiency Rating - New Construction Market)
March, 2015 (85% Min Efficiency Rating - Existing Buildings Market)

In August of 2010, Natural Resources Canada's (NRCan's) Office of Energy Efficiency (OEE) Natural Resources Canada (NRCan) proposed to amend Canada's ENERGY EFFICIENCY REGULATIONS (the Regulations) to require dealers to comply with minimum energy performance standards (MEPS) for commercial gas and oil-fired boilers, imported or shipped inter-provincially, for sale or lease in Canada. NRCan proposes that commercial packaged boilers meet minimum efficiency ratings of 90% for the New Construction mark and 85% for the Replacement Market, effective March, 2015.

Manitoba Hydro proposes that the Provincial Government enact regulations under The Energy Act, requiring a minimum performance level for all natural gas boilers sold to new Manitoba buildings. By April 1 2013, Manitoba Hydro proposes that all commercial boilers be condensing, with a minimum efficiency rating of 90%. This regulation is equivalent to the proposed federal regulation, but will be enacted two years earlier.

Manitoba Hydro will play a material role in the development of a provincial efficiency regulation for commercial natural gas boilers. Manitoba Hydro staff will assist the Manitoba Government by providing technical and market data, hosting an industry consultation with contractors and other interested parties, preparing a formal market impact study, and providing general guidance to regulatory staff. The Commercial HVAC Program will continue to expedite market adoption of high efficiency boilers in all commercial buildings from it pre-program average of 30% to an estimated 72% by April 2013, thus facilitating the adoption of a provincial performance standard two years earlier than the rest of Canada.

Manitoba Hydro proposes that the Provincial Government enact regulations under The Energy Act, requiring a minimum performance level for all natural gas boilers sold to existing Manitoba buildings. By March 2015, Manitoba Hydro proposes that all commercial boilers be condensing, with a minimum efficiency rating of 90%. This is approximately 5% higher than the proposed federal regulation requiring all boilers sold to be at least 85% efficient (near-condensing).

Manitoba Hydro will play a material role in the development of a provincial efficiency regulation for commercial natural gas boilers. Manitoba Hydro staff will assist the Manitoba Government by providing technical and market data, hosting an industry consultation with contractors and other interested parties, preparing a formal market impact study, and providing general guidance to regulatory staff. The Commercial HVAC Program will continue to expedite market adoption of high efficiency boilers in all commercial buildings from it pre-program average of 30% to an estimated 75% by March 2015, thus facilitating the adoption of a higher performance standard in Manitoba.

<u>Commercial Hot Water Tanks</u>
National Resources Canada (FEDERAL)
Bulletin published: June 2010
Test Standard: CAN/CSA-P.3-04 "Testing Method for Measuring Energy Consumption and Determining Efficiencies of Gas-Fired Storage Water Heaters."
Proposed Effective date(s): January 1, 2016

The Office of Energy Efficiency (OEE) of Natural Resources Canada (NRCan) is proposing to amend Canada's Energy Efficiency Regulations (the Regulations) under which dealers in Canada would be required to comply with higher efficiency requirements for gas and oil water heaters and new reporting requirements for electric water heaters. For the first time in Canada, commercial water heaters and tankless water heaters will have minimum efficiency requirements. These proposed revisions would apply to water heaters that are imported or shipped across provincial boundaries for sale or lease in Canada and would require all tank natural gas water heaters sold in Canada to be condensing efficiency (minimum 90% thermal efficiency) by 2016.

The Commercial Water Heater Program will work with the provincial government to pass a regulation under The Energy Act, imposing a minimum performance level of 90% thermal efficiency (TE) for all commercial natural gas water heaters, including tankless water heaters, offered for sale or for lease in Manitoba.

Based on past experience with provincial codes, Manitoba Hydro staff will assist the Manitoba Government by providing technical and market data, hosting an industry consultation with contractors and other interested parties, preparing a formal market impact study, and providing general guidance to regulatory staff. The Commercial Water Heater Program will also help to expedite market adoption of

high efficiency water heaters in Manitoba commercial buildings through rebates and education. Manitoba Hydro's active involvement will expedite market transformation, and thus facilitate the adoption of the provincial efficiency regulation.

In the area of Other Commercial Equipment, Manitoba Hydro estimates changes will realize natural gas savings of 1.7 million cubic meters by 2026/27.

At an Industrial level, Manitoba Hydro currently undertakes codes and standards development work with the following organizations:

- Natural Resources Canada (NRCAN)
- Province of Manitoba
- Canadian Standards Association (CSA), including BC Hydro, Hydro Quebec, Ontario Power Authority, Ontario Ministry of Energy, etc)
- Centre for Energy Advancement through Technological Innovation (CEATI)
- US Department of Energy (DOE)
- Institute of Electronic and Electrical Engineers (IEEE)
- International Electrotechnical Commission (IEC)
- American Council for an Energy-Efficient Economy (ACEEE)
- Electric Power Research Institute (EPRI)
- Energy Solutions Center (ESC)
- American Society of Heating, Refrigeration and Air-Conditioning Engineers (ASHRAE)
- Canadian Gas Association (CGA)

This work pertains primarily to industrial and commercial equipment that incorporates or applies to electric motors, variable speed drives, air compressors, compressed air systems, fans, pumps, transformers, power quality systems, battery charges, uninterruptible power supplies, lighting systems, refrigeration, heating, ventilation and air conditioning systems, and building envelope incorporating both natural gas and electric supply.

Areas of involvement include, test methods for determination of energy efficiency, performance standards, application guides for efficiency test methods and performance standards and repair standards (to maintain efficiency).

6 OTHER INTERNAL DEMAND SIDE MANAGEMENT FUNDING

6.1 AFFORDABLE ENERGY FUND

The Affordable Energy Fund is an internal fund established as a result of the Winter Heating Cost Control Act. The purpose of the Fund is to provide support for programs and services that achieve specific objectives outlined under the Act including encouraging energy efficiency and conservation through programs and services for rural and northern Manitobans, low income customers and seniors and encouraging the use of alternative energy sources such as renewable energy.

Affordable Energy Fund - Budget

Manitoba Hydro established the Affordable Energy Fund following the passing of the Winter Heating Cost Control Act on November 20, 2006 in the Manitoba Legislature. The Affordable Energy Fund supports Manitoba Hydro's sustainable development initiatives.

The following projects and associated funding levels have been approved for support by the Affordable Energy Fund:

Affordable Energy Fund Budget
(Millions)

	Total Budget
Lower Income Program	23.1
Geothermal Support	1.6
Community Support and Outreach	0.8
Oil and Propane Heated Homes	0.3
Special Projects	0.0
Residential ecoENERGY Audits	0.5
Oil and Propane Furnace Replacement	0.2
Solar Water Heaters	0.3
Residential Loan	2.5
Oil and Propane Heated Homes - Additional funding	0.3
Unallocated	0.1
Community Energy Development	
ecoENERGYProgram Funding	4.1
Residential Loan - Additional funding	0.4
Power Smart PAYS Financing Program	0.4
Energy & Resource Fund	0.8
Manitoba Electric Bus	1.2
FortWhyte EcoVillage	0.1
Diesel Community Green Pilot Demonstration	0.4
Métis Generation Fund	0.5
TOTALS	$37.4

As of March 31st, 2012 approximately $16.9 million of the Affordable Energy Fund had been spent, leaving the remaining $20.5 million to be allocated over the 2012/13 to 2026/27 horizon, of which $19.1 million is classified as part of the overall Total Internal Demand Side Management budget (as outlined in Section 7).

Affordable Energy Fund Budget
(Millions)

	Total Budget	Expeditures to Date	Remaining Total Budget
Lower Income Program	23.1	8.8	14.3
Geothermal Support	1.6	1.3	0.3
Community Support and Outreach	0.8	0.4	0.3
Oil and Propane Heated Homes	0.3	0.2	0.0
Special Projects			
Residential ecoENERGY Audits	0.5	0.5	0.0
Oil and Propane Furnace Replacement	0.2	0.1	0.0
Solar Water Heaters	0.3	0.3	0.0
Residential Loan	2.5	0.8	1.7
Oil and Propane Heated Homes - Additional funding	0.3	0.0	0.3
Unallocated	0.1	0.0	0.1
Community Energy Development			
ecoENERGYProgram Funding	4.1	2.8	1.3
Residential Loan - Additional funding	0.4	0.0	0.4
Power Smart PAYS Financing Program	0.4	0.0	0.4
Energy & Resource Fund *	0.8	0.8	0.0
Manitoba Electric Bus *	1.2	0.7	0.5
FortWhyte EcoVillage *	0.1	0.1	0.0
Diesel Community Green Pilot Demonstration *	0.4	0.0	0.4
Métis Generation Fund *	0.5	0.0	0.5
TOTALS	$37.4	$16.9	$20.5

Note:
** Non Demand Side Management Budget*
Figures may not add due to rounding

The following table identifies the programs and associated funding levels that the Affordable Energy Fund will support over the Power Smart Planning horizon.

Affordable Energy Fund Budget
(Millions 2012 $)

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22-2026/27	Total
Lower Income Program	3.8	3.8	3.7	3.0	0.0	0.0	0.0	0.0	0.0	0.0	14.3
Geothermal Support	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Community Support and Outreach	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Oil and Propane Heated Homes	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Special Projects											
Residential ecoENERGY Audits	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Oil and Propane Furnace Replacement	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Solar Water Heaters	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Residential Loan	0.5	0.4	0.4	0.2	0.1	0.0	0.0	0.0	0.0	0.0	1.7
Oil and Propane Heated Homes - Additional funding	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Unallocated	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
Community Energy Development											
ecoENERGYProgram Funding	1.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.3
Residential Loan - Additional funding	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Power Smart PAYS Financing Program	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.4
Energy & Resource Fund *	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Manitoba Electric Bus *	0.2	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.5
FortWhyte EcoVillage *	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Diesel Community Green Pilot Demonstration *	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4
Métis Generation Fund *	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5
Annual Budget	7.2	5.0	4.4	3.4	0.3	0.1	0.0	0.0	0.0	0.0	20.5
Cumulative Budget, 2012 - 2026	$7.2	$12.2	$16.6	$20.0	$20.3	$20.4	$20.5	$20.5	$20.5	$20.5	$20.5

Note: Annual interest accruals are not included in the above forecast.

Low Income Program

The Affordable Energy Fund supports the Lower Income Energy Efficiency Program by targeting low-income Manitobans through an individual, community and neighbourhood approach.

Geothermal Support

The Affordable Energy Fund provides funding to support the application of geothermal technology. A portion of the fund is being used to subsidize the interest rate for Residential Earth Power Loan program participants from 6.5 to 4.9 percent for the first five years of the loan term.

Community Support and Outreach

The Affordable Energy Fund provides funding for additional resources for the purpose of encouraging rural and northern customers to participate in Power Smart initiatives.

Oil and Propane-Heated Homes

The Affordable Energy Fund provides incentives to allow customers with wood, oil or propane heating to participate in Power Smart programs. The estimated savings of the other fuel types resulting from the installation of insulation in customer homes are provided in the next section of this report. (Note: Additional funding provided through the special projects category)

Special Projects

Residential Energy Assessment Service (ecoENERGY Audits)

The Affordable Energy Fund contributes the incremental costs associated with providing Manitoba Hydro's In-home Energy Assessment service under the Federal ecoENERGY Retrofit program to rural and northern Manitobans.

Oil & Propane Furnace Replacement

Manitoba Hydro extended the eligibility for the Power Smart Furnace Replacement Program to those customers upgrading an oil or propane furnace to a high efficiency electric or natural gas furnace.

Residential Solar Water Heating Program

Manitoba Hydro is partnering with Natural Resources Canada to deliver a residential solar water heating initiative in Manitoba. This initiative supports the application of solar domestic hot water pre-heating systems and the development of the local solar industry.

Power Smart Residential Loan

The Affordable Energy Fund provides funding to reduce the interest rate for the Power Smart Residential Loan from a cost recovery rate of 5.5% to a rate of 3.9%.

Oil and Propane-Heated Homes – Additional Funding

This initiative provides further funding to extend the eligibility of Power Smart programs to include homes currently heated by a source other than electricity and natural gas. As this additional funding is coming from a separate Affordable Energy Fund category than the original funding, it is tracked separately.

Community Energy Development

ecoENERGY Program Funding – Additional Funding

Additional funding has been allocated to support the cost of offering audits in Manitoba, involving a $100 subsidy for each audit plus the incremental cost of offering audits in rural and northern Manitoba.

Power Smart Residential Loan – Additional Funding

The Affordable Energy Fund provides additional funding to reduce the interest rate for the Power Smart Residential Loan from the cost recovery rate to a rate of 3.9%.

Power Smart PAYS Financing Program

This initiative provides funding to reduce the interest rate for the PAYS financing program from the cost recovery rate to a rate of 3.9%.

Energy and Resource Fund

The Affordable Energy Fund provided funding to the Energy and Resource Fund. Managed by the First Peoples Economic Growth Fund, this joint initiative between the Government of Manitoba and the Assembly of Manitoba Chiefs was created to maximize First Nations participation in Major Energy and Resource Projects.

Manitoba Electric Bus

Funding is provided to support the Manitoba Electric Bus Project; a joint initiative among the Province of Manitoba, Manitoba Hydro, Red River College, New Flyer Industries and Mitsubishi Heavy Industries. The objective of the project is to develop a commercially viable all-electric bus design with near-zero emissions for use in urban transit systems.

FortWhyte EcoVillage

The Affordable Energy Fund supported the research and design of a world-class ecovillage on land belonging to FortWhyte Alive.

Diesel Community Green Pilot Demonstration

This initiative provides funding to support a pilot demonstration focusing on green technologies in one of four diesel communities.

Métis Generation Fund for Resource & Energy Development

The Affordable Energy Fund is providing funding to the Métis Generation fund, managed by the Métis Economic Development Organization. This fund was created to enable Metis-owned businesses in Manitoba to invest in business growth and development within the resource and energy sectors in Manitoba.

Affordable Energy Fund - Other Fuel Savings

Through funding from the Affordable Energy Fund, residential customers using heating sources other than natural gas and electricity are eligible to participate in the Home Insulation, Water & Energy Saver Program and Oil & Propane Furnace Replacement programs. The following table provides the oil and propane fuel savings estimated to be achieved through this funding.

It is estimated that savings of 481,300 litres of fuel oil and 156,900 litres of propane will be achieved from 2012/13 to 2026/27.

Affordable Energy Fund Other Fuel Savings
2012/13 - 2026/27
(000s, litres)

	2012/13	2013/14	2014/15 - 2026/27
Fuel Oil Savings			
Home Insulation Program	10.5	10.5	31.5
Water & Energy Saver Program	5.9	5.9	5.9
Oil & Propane Furnace Replacement	46.0	46.0	319.1
Annual Fuel Oil Savings	62.4	62.4	356.5
Cumulative Fuel Oil Savings, 2012-2026	62.4	124.8	481.3
Propane Savings			
Home Insulation Program	6.0	6.0	18.0
Water & Energy Saver Program	4.0	4.0	4.0
Oil & Propane Furnace Replacement	12.9	12.9	89.1
Annual Propane Savings	22.9	22.9	111.1
Cumulative Popane Savings, 2012-2026	22.9	45.8	156.9

6.2 LOWER INCOME NATURAL GAS FURNACE REPLACEMENT

The Lower Income Natural Gas Furnace Replacement budget is an internal allocation established as a result of Public Utility Board Order 99/07. The purpose of the allocation is to establish and administer a Furnace Replacement Program for low income customers.

Lower Income Natural Gas Furnace Replacement - Budget

The following table outlines the planned expenditures totalling $11.5 million over the next five years.

Lower Income Natural Gas Furnace Replacement Budget
(Millions 2012$)

	2012/13	2013/14	2014/15	2015/16	2016/17	Total
Lower Income Program						
Annual Budget Furnace Replacement	2.4	2.4	2.4	2.2	2.2	11.5
Cumulative Budget, 2012-2026	$2.4	$4.8	$7.1	$9.3	$11.5	$11.5

Note: Figures may not add due to rounding

7 TOTAL INTERNAL DEMAND SIDE MANAGEMENT BUDGET

The Total Internal Demand Side Management Budget includes the following internal sources:

- Electric Power Smart Utility Budget - $337 million (as outlined in Section 2.2)
- Natural Gas Power Smart Utility Budget- $84 million (as outlined in Section 3.2)
- Affordable Energy Fund Budget - $19 million (as outlined in Section 6.1)
- Lower Income Furnace Replacement Budget - $12 million (as outlined in Section 6.2)

The following table outlines the total projected DSM budget including all internal sources of funding to 2026/27. A total investment of $452 million is planned for the period of 2012/13 to 2026/27.

Forecasted Internal DSM Budget
2012/13 - 2026/27
(Millions 2012 $)

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	Total
Electric DSM																
Electric Power Smart	29.4	29.3	26.2	25.5	24.9	23.6	22.6	20.9	19.9	19.7	19.7	20.1	19.7	18.9	17.2	337.5
Affordable Energy Fund	2.7	0.9	0.7	0.6	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.1
Annual Electric Budget	$32.1	$30.3	$26.9	$26.0	$24.9	$23.6	$22.7	$20.9	$19.9	$19.7	$19.7	$20.1	$19.7	$18.9	$17.2	$342.6
Natural Gas DSM																
Natural Gas Power Smart	10.0	9.5	9.1	7.9	7.6	5.5	4.6	3.6	3.6	3.3	3.4	3.9	3.8	3.8	3.8	83.5
Affordable Energy Fund	3.6	3.5	3.5	2.8	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13.6
Lower Income Furnace Replacement Budget	2.4	2.4	2.4	2.2	2.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.5
Annual Natural Gas Budget	$15.9	$15.4	$15.0	$12.9	$10.0	$5.6	$4.6	$3.6	$3.6	$3.3	$3.4	$3.9	$3.8	$3.8	$3.8	$108.7
Oil and Propane DSM																
Affordable Energy Fund	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3
Annual Oil and Propane Budget	$0.1	$0.1	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.3
Manitoba Hydro Annual Budget	$48.1	$45.8	$42.0	$38.9	$34.9	$29.2	$27.3	$24.5	$23.5	$23.1	$23.0	$24.0	$23.5	$22.7	$21.0	
Cumulative Budget 2012-2026	$48.1	$93.9	$135.9	$174.9	$209.8	$239.0	$266.3	$290.8	$314.3	$337.4	$360.4	$384.4	$407.9	$430.7	$451.6	$451.6

When combined with spending to date, a total internal investment of $940 million is planned for the period of 2012/13 to 2026/27.

Total Internal DSM Budget
1989/90 - 2026/27
(Millions 2012 $)

	Expenditures to date 1989-2011	15 yr planning horizon 2012-2026	Total 1989-2026
Electric DSM			
Electric Power Smart	395.7	337.5	733.2
Affordable Energy Fund	7.6	5.1	12.7
Annual Electric Budget	$403.3	$342.6	$745.9
Natural Gas DSM			
Natural Gas Power Smart	72.6	83.5	156.1
Affordable Energy Fund	8.1	13.6	21.8
Lower Income Furnace Replacement Budget	4.2	11.5	15.7
Annual Natural Gas Budget	$84.9	$108.7	$193.6
Oil and Propane DSM			
Affordable Energy Fund	0.3	0.3	0.6
Annual Oil and Propane Budget	$0.3	$0.3	$0.6
Cumulative Budget 1989 -2026	$488.5	$451.6	$940.1

Note: Expenditures to date presented in Millions 2012$

8 OTHER EXTERNAL DEMAND SIDE MANAGEMENT FUNDING

Manitoba Hydro's Power Smart programs are supported by funding from external organizations as outlined in the following table.

The Lower Income Energy Efficient Program includes partnership funding from the Provincial Government. This external funding is expected to total $11.0 million over the period of 2012/13 to 2026/27. Manitoba Hydro will continue to encourage energy efficiency and conservation to lower income Manitobans throughout the 15-year planning horizon. Program staff will review programming and spending prior to 2015/16 and determine what opportunities and funding sources are available beyond that date. A placeholder for the projected funds required to support these continued efforts is conveyed in the table below as *Unidentified funding sources*.

External funding is provided by the Federal Government through Natural Resources Canada to support Bioenergy Optimization demo projects. This funding is expected to total $0.2 million over the period of 2012/13 to 2026/27. Energy savings associated with the aforementioned demo projects have not been included in the 2012/13 Power Smart Plan.

External Funding Budget
2012/13 - 2026/27
(Millions 2012 $)

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18-2026/27	Cumulative, 2012-2026
External Funding							
Lower Income Energy Efficient Program	2.2	2.2	2.2	2.2	2.2	0.0	11.0
Bioenergy Optimization Program	0.2	0.0	0.0	0.0	0.0	0.0	0.2
Unidentified Funding Sources	0.0	0.0	0.0	0.3	3.3	0.0	3.6
Total External Funding	$2.4	$2.2	$2.2	$2.5	$5.5	$0.0	$14.8
Cumulative Budget, 2012-2026	$2.4	$4.6	$6.8	$9.3	$14.8	$14.8	$14.8

APPENDIX A – 2012/13 POWER SMART PLAN ELECTRIC

APPENDIX A.1 - ANNUAL CAPACITY SAVINGS (MW)

APPENDIX A.2 - ANNUAL ENERGY SAVINGS (GW.H)

APPENDIX A.3 - ANNUAL UTILITY COSTS

APPENDIX A.4 - ANNUAL PROGRAM ADMINISTRATION COSTS

APPENDIX A.5 - ANNUAL PROGRAM INCENTIVE COSTS

2012/13 PS Plan
Annual Capacity Savings (MW)

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27		MW at Generation 2026/27
RESIDENTIAL																	
Incentive Based																	
Home Insulation Program	1.0	2.7	4.3	5.7	6.9	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4		8.5
Water and Energy Saver Program	0.4	0.9	1.5	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7		2.0
Lower Income Energy Efficiency Program	0.4	1.4	2.3	3.2	4.0	4.4	4.4	4.4	4.2	4.0	3.8	3.4	3.1	2.9	2.8		3.2
Refrigerator Retirement Program	1.0	2.7	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	3.4	2.5	0.9	0.3	0.2		0.2
Subtotal	2.8	7.7	11.4	13.9	15.9	16.9	16.9	16.9	16.7	16.5	16.3	15.0	13.1	12.3	12.1	4%	13.8
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	0.1	0.3	0.5	0.6	0.8	1.0	1.2	1.3	1.5	1.7	1.9	2.1	2.2	2.4	2.6		3.0
Residential Earth Power Loan	0.2	0.5	0.9	1.2	1.6	2.0	2.4	2.8	3.3	3.8	4.3	4.8	5.4	5.6	5.6		6.4
Power Smart PAYS Financing	0.1	0.4	0.8	1.0	1.3	1.6	2.0	2.3	2.6	2.9	3.2	3.5	3.9	4.2	4.5		5.1
Subtotal	0.4	1.2	2.1	2.9	3.7	4.6	5.5	6.5	7.4	8.4	9.4	10.4	11.4	12.2	12.7	4%	14.5
COMMERCIAL																	
Commercial Lighting Program	3.5	9.7	15.4	20.4	25.0	29.4	33.5	37.4	41.0	44.4	46.7	48.1	49.5	50.7	51.7		59.0
Commercial Custom Measures Program	0.1	0.4	0.6	0.9	1.1	1.3	1.6	1.9	2.1	2.4	2.6	2.9	3.1	3.4	3.7		4.2
Commercial Windows Program	0.5	1.2	1.8	2.2	2.6	2.9	3.2	3.5	3.7	4.0	4.2	4.5	4.7	4.9	5.1		5.9
Commercial HVAC Program - Chiller	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
City of Winnipeg Power Smart Agreement	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0		0.0
Commercial Refrigeration Program	0.1	0.2	0.4	0.5	0.7	0.9	1.1	1.3	1.6	1.8	2.1	2.4	2.7	2.9	2.9		3.3
Commercial Insulation Program	0.5	1.3	1.9	2.4	2.8	3.2	3.5	3.8	4.0	4.2	4.3	4.5	4.6	4.8	4.9		5.6
Commercial Earth Power Program	0.2	0.6	1.0	1.4	1.8	2.2	2.6	3.0	3.3	3.7	4.1	4.6	5.0	5.4	5.8		6.6
New Buildings Program	1.0	3.5	6.7	10.2	13.9	17.7	21.6	23.5	23.5	23.5	23.5	23.5	23.5	23.5	23.5		26.7
Commercial Building Optimization Program	0.1	0.3	0.6	0.8	1.1	1.4	1.7	2.0	2.3	2.7	2.9	3.1	3.4	3.6	3.8		4.3
Internal Retrofit Program	0.1	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3		0.3
Commercial Kitchen Appliance Program	0.0	0.4	1.0	1.7	2.0	2.1	2.1	2.1	2.1	2.1	2.1	1.8	1.2	0.5	0.2		0.3
Commercial Clothes Washers Program	0.0	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.4	0.4		0.4
Network Energy Management Program	0.2	0.9	1.4	1.4	1.4	1.4	1.4	1.3	1.3	1.3	1.2	0.5	0.0	0.0	0.0		0.0
CO2 Sensors	0.0	0.1	0.2	0.3	0.4	0.6	0.8	0.9	0.9	0.9	0.9	0.9	1.0	1.0	0.9		1.1
Subtotal	6.4	19.0	31.5	42.8	53.5	63.7	73.8	81.3	86.6	91.8	95.5	97.5	99.4	101.3	103.1	33%	117.6
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	0.0	0.0	0.1	0.2	0.2	0.2	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.6		0.7
Subtotal	0.0	0.0	0.1	0.2	0.2	0.2	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.6	0%	0.7
Market Effects																	
Agricultural Heat Pad Program	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.4	0.5	0.6	0.7		0.8
Commercial Parking Lot Controller Program	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
Commercial Rinse & Save Program	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
Subtotal	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.4	0.5	0.6	0.7	0%	0.8
INDUSTRIAL																	
Performance Optimization Program	1.1	3.1	5.1	7.1	9.1	11.1	13.2	15.2	17.2	19.2	21.2	23.2	25.2	27.2	29.3		32.2
Subtotal	1.1	3.1	5.1	7.1	9.1	11.1	13.2	15.2	17.2	19.2	21.2	23.2	25.2	27.2	29.3	9%	32.2
CONSERVATION SUBTOTAL	10.8	31.4	50.4	67.1	82.7	96.9	109.9	120.3	128.5	136.5	143.1	146.9	150.2	154.2	158.5	51%	179.5
LOAD MANAGEMENT																	
Curtailable Rate Program	146.4	146.4	146.4	146.4	146.4	146.4	146.4	146.4	146.4	146.4	146.4	146.4	146.4	146.4	146.4		161.1
LOAD MANAGEMENT SUBTOTAL	146.4	146.4	146.4	146.4	146.4	146.4	146.4	146.4	146.4	146.4	146.4	146.4	146.4	146.4	146.4	47%	161.1
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	0.5	1.8	3.1	4.5	5.7	6.5	7.3	7.9	8.2	8.2	8.2	8.2	8.2	8.2	8.2		9.0
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	0.5	1.8	3.1	4.5	5.7	6.5	7.3	7.9	8.2	8.2	8.2	8.2	8.2	8.2	8.2	3%	9.0
Program Impacts (at meter)	158	180	200	218	235	250	264	275	283	291	298	302	305	309	313	100%	
Program Impacts (at generation)	174	199	222	242	261	278	294	306	316	325	332	337	340	345	350		
Codes, Standards & Regulations (at meter)	7	21	35	53	75	90	100	108	116	125	132	133	134	137	141		
Codes, Standards & Regulations (at generation)	8	24	40	61	85	102	113	123	133	142	150	151	153	156	161		
POWER SMART 2012 to 2026 Impacts (at meter)	165	201	235	271	309	340	363	383	400	416	430	434	439	445	454		
POWER SMART 2012 to 2026 Impacts (at generation)	182	223	262	303	346	381	407	430	449	467	483	488	493	501	511		
POWER SMART SAVINGS TO DATE																	
Incentive Based Program Impacts (at meter)	193	193	193	194	192	191	191	189	189	188	185	183	179	169	165		
Incentive Based Program Impacts (at generation)	217	217	217	218	216	215	214	213	212	212	208	205	202	190	185		
Customer Service Initiatives Program Impacts (at meter)	8	8	8	8	8	8	8	8	8	8	8	8	7	7	7		
Customer Service Initiatives Program Impacts (at generation)	9	9	9	9	9	9	9	9	9	9	9	9	8	8	8		
Discontinued Programs (at meter)	48	42	42	29	29	29	29	29	29	29	28	27	27	26	26		
Discontinued Programs (at generation)	54	47	47	33	33	33	33	33	33	33	32	31	30	30	30		
Impacts of Codes & Standards (at meter)	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108		
Impacts of Codes & Standards (at generation)	123	123	123	123	123	123	123	123	123	123	123	123	123	123	123		
TOTAL MW (at meter)	522	552	586	611	647	676	699	717	734	749	759	760	760	756	760		
TOTAL MW (at generation)	586	619	658	686	728	761	787	807	826	844	854	856	856	852	857		

Note: May not add up due to rounding.

2012/13 PS Plan
Annual Energy Savings (GW.h)

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27		GW.h at Generation 2026/27
RESIDENTIAL																	
Incentive Based																	
Home Insulation Program	2.4	5.6	8.5	11.0	13.3	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9	13.9		15.8
Water and Energy Saver Program	1.9	4.8	7.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7	8.7		10.0
Lower Income Energy Efficiency Program	1.5	3.9	6.2	8.4	10.4	11.2	11.2	11.1	10.7	10.2	9.4	8.5	7.8	7.4	7.0		8.0
Refrigerator Retirement Program	8.7	23.8	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3	30.3	22.3	8.4	2.4	1.7		1.9
Subtotal	14.4	38.1	52.7	58.4	62.7	64.2	64.2	64.1	63.6	63.1	62.4	53.5	38.8	32.4	31.3	4%	35.7
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	0.2	0.6	0.9	1.3	1.6	2.0	2.3	2.6	3.0	3.3	3.7	4.0	4.4	4.7	5.0		5.8
Residential Earth Power Loan	1.0	2.5	3.9	5.4	7.0	8.7	10.4	12.3	14.2	16.2	18.3	20.6	22.9	23.6	23.6		26.9
Power Smart PAYS Financing	0.3	1.0	1.6	2.1	2.7	3.3	3.9	4.6	5.2	5.8	6.4	7.1	7.7	8.3	9.0		10.2
Subtotal	1.6	4.0	6.4	8.8	11.3	14.0	16.7	19.5	22.4	25.4	28.5	31.7	35.0	36.6	37.6	5%	42.9
COMMERCIAL																	
Commercial Lighting Program	11.9	34.6	55.0	73.1	90.1	105.8	120.8	134.8	148.0	160.4	168.9	173.8	178.9	183.4	187.0		213.2
Commercial Custom Measures Program	0.6	1.5	2.4	3.4	4.3	5.2	6.2	7.2	8.1	9.1	10.1	11.0	12.0	13.0	14.0		15.9
Commercial Windows Program	1.5	3.3	4.7	5.8	6.6	7.4	8.2	8.9	9.6	10.2	10.8	11.4	12.0	12.6	13.1		15.0
Commercial HVAC Program - Chiller	0.4	1.5	2.6	3.9	5.2	6.6	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5		8.6
City of Winnipeg Power Smart Agreement	0.2	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.2	0.0	0.0		0.0
Commercial Refrigeration Program	0.7	1.9	3.3	4.8	6.3	8.0	9.8	11.7	13.8	16.0	18.4	21.1	24.0	25.4	25.4		28.9
Commercial Insulation Program	1.6	3.5	5.1	6.4	7.5	8.4	9.1	9.8	10.3	10.8	11.2	11.6	12.0	12.3	12.6		14.3
Commercial Earth Power Program	1.2	2.8	4.5	6.1	7.7	9.4	11.0	12.7	14.3	16.0	17.7	19.5	21.2	23.0	24.8		28.2
New Buildings Program	4.9	15.3	27.5	40.8	54.7	69.2	84.2	88.7	88.7	88.7	88.7	88.7	88.7	88.7	88.7		101.1
Commercial Building Optimization Program	0.5	1.6	2.8	3.9	5.4	7.0	8.5	9.9	11.5	13.2	14.5	15.5	16.7	18.0	19.0		21.6
Internal Retrofit Program	0.5	1.3	1.8	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0		2.3
Commercial Kitchen Appliance Program	0.1	0.4	1.0	1.6	2.0	2.2	2.3	2.3	2.3	2.3	2.3	2.1	1.6	1.0	0.7		0.8
Commercial Clothes Washers Program	0.1	0.2	0.3	0.4	0.5	0.6	0.6	0.7	0.8	0.8	0.8	0.9	0.9	0.8	0.7		0.8
Network Energy Management Program	0.5	2.4	3.7	3.7	3.7	3.7	3.6	3.6	3.6	3.6	3.1	1.2	0.0	0.0	0.0		0.0
CO2 Sensors	0.1	0.2	0.3	0.5	0.7	0.9	1.1	1.2	1.2	1.3	1.3	1.3	1.3	1.3	1.3		1.5
Subtotal	24.7	70.8	115.5	156.8	197.1	236.8	275.5	301.4	322.1	342.2	357.8	368.1	379.0	389.0	396.7	54%	452.3
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	0.0	0.2	0.4	0.6	0.8	0.9	1.0	1.2	1.3	1.4	1.5	1.7	1.8	1.9	2.0		2.3
Subtotal	0.0	0.2	0.4	0.6	0.8	0.9	1.0	1.2	1.3	1.4	1.5	1.7	1.8	1.9	2.0	0%	2.3
Market Effects																	
Agricultural Heat Pad Program	1.0	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	2.3	3.1	3.9	4.8	5.6		6.4
Commercial Parking Lot Controller Program	1.7	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2		2.6
Commercial Rinse & Save Program	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
Subtotal	2.7	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.5	5.3	6.2	7.0	7.9	1%	9.0
INDUSTRIAL																	
Performance Optimization Program	7.0	19.9	32.8	45.7	58.6	71.5	84.4	97.3	110.2	123.1	136.0	148.9	161.8	174.7	187.6		206.3
Subtotal	7.0	19.9	32.8	45.7	58.6	71.5	84.4	97.3	110.2	123.1	136.0	148.9	161.8	174.7	187.6	26%	206.3
CONSERVATION SUBTOTAL	50.4	137.1	211.9	274.4	334.6	391.4	445.9	487.5	523.7	559.3	590.6	609.1	622.5	641.6	663.2	90%	748.5
LOAD MANAGEMENT																	
Curtailable Rate Program	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
LOAD MANAGEMENT SUBTOTAL	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%	0.0
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	4.6	15.5	27.2	39.6	49.8	57.0	64.0	69.7	71.9	71.9	71.9	71.9	71.9	71.9	71.9		79.1
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	4.6	15.5	27.2	39.6	49.8	57.0	64.0	69.7	71.9	71.9	71.9	71.9	71.9	71.9	71.9	10%	79.1
Program Impacts (at meter)	55	153	239	314	384	448	510	557	596	631	663	681	694	714	735	100%	
Program Impacts (at generation)	62	173	270	354	434	506	575	629	672	712	747	767	782	804	828		
Codes, Standards & Regulations (at meter)	33	91	148	227	314	382	435	484	532	578	618	632	648	669	698		
Codes, Standards & Regulations (at generation)	37	103	169	259	358	435	496	552	606	659	705	721	738	763	796		
POWER SMART 2012 to 2026 Impacts (at meter)	88	243	387	541	698	830	945	1,041	1,127	1,209	1,281	1,313	1,342	1,383	1,433		
POWER SMART 2012 to 2026 Impacts (at generation)	99	276	439	613	792	941	1,072	1,180	1,278	1,371	1,452	1,488	1,520	1,567	1,624		
POWER SMART SAVINGS TO DATE																	
Incentive Based Program Impacts (at meter)	868.0	867.6	867.2	868.3	865.9	863.9	861.3	857.4	856.2	852.2	820.5	800.3	776.3	713.0	681.1		
Incentive Based Program Impacts (at generation)	974.6	974.2	973.7	974.9	972.3	970.0	967.0	962.6	961.2	956.7	921.7	899.5	873.1	801.6	766.2		
Customer Service Initiatives Program Impacts (at meter)	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.7	20.3	19.7	15.9	15.9	14.5		
Customer Service Initiatives Program Impacts (at generation)	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.6	23.2	22.4	18.1	18.1	16.6		
Discontinued Programs (at meter)	312.1	289.0	252.6	230.7	228.7	226.1	224.2	223.8	223.8	223.8	212.5	203.9	195.4	184.7	182.1		
Discontinued Programs (at generation)	353.6	327.3	285.7	260.8	258.6	255.6	253.4	252.9	252.9	252.9	240.0	230.3	220.6	208.3	205.4		
Impacts of Codes & Standards (at meter)	472.8	472.8	472.8	472.8	472.8	472.8	472.8	472.8	472.8	472.8	472.8	472.8	472.8	472.8	472.8		
Impacts of Codes & Standards (at generation)	538.3	538.3	538.3	538.3	538.3	538.3	538.3	538.3	538.3	538.3	538.3	538.3	538.3	538.3	538.3		
TOTAL GW.h (at meter)	1,761	1,893	2,001	2,133	2,287	2,414	2,524	2,616	2,701	2,779	2,807	2,810	2,802	2,769	2,784		
TOTAL GW.h (at generation)	1,990	2,139	2,260	2,411	2,585	2,729	2,854	2,958	3,054	3,142	3,175	3,179	3,171	3,133	3,150		

Note: May not add up due to rounding.

2012/13 PS Plan
Annual Utility Costs
(000's in 2012 $)

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	Cumulative Total	
RESIDENTIAL																	
Incentive Based																	
Home Insulation Program	$1,248	$1,167	$1,087	$1,010	$957	$220	$57	$57	$57	$57	$57	$57	$57	$57	$57	$6,206	
Water and Energy Saver Program	$784	$784	$784	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,352	
Lower Income Energy Efficiency Program	$328	$312	$297	$248	$236	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,421	
Refrigerator Retirement Program	$2,283	$2,222	$58	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,563	
Subtotal	$4,643	$4,485	$2,227	$1,258	$1,193	$220	$57	$57	$57	$57	$57	$57	$57	$57	$57	$14,543	6%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Residential Earth Power Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Power Smart PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
COMMERCIAL																	
Commercial Lighting Program	$6,172	$5,989	$5,383	$5,182	$4,992	$4,815	$4,655	$4,498	$4,352	$4,209	$4,080	$3,950	$3,536	$3,206	$1,473	$66,494	
Commercial Custom Measures Program	$247	$261	$260	$260	$259	$268	$267	$266	$266	$265	$274	$273	$272	$271	$270	$3,978	
Commercial Windows Program	$492	$437	$395	$292	$285	$280	$276	$273	$270	$268	$266	$265	$264	$263	$262	$4,589	
Commercial HVAC Program - Chiller	$206	$217	$228	$239	$250	$262	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,402	
City of Winnipeg Power Smart Agreement	$28	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$28	
Commercial Refrigeration Program	$294	$302	$271	$279	$291	$305	$315	$333	$348	$369	$390	$417	$449	$0	$0	$4,361	
Commercial Insulation Program	$531	$479	$437	$388	$358	$335	$305	$290	$279	$269	$262	$256	$251	$247	$244	$4,929	
Commercial Earth Power Program	$328	$353	$353	$353	$340	$340	$340	$340	$340	$340	$356	$356	$356	$356	$356	$5,206	
New Buildings Program	$835	$641	$774	$953	$1,048	$1,145	$1,243	$0	$0	$0	$0	$0	$0	$0	$0	$6,639	
Commercial Building Optimization Program	$112	$119	$119	$133	$166	$153	$139	$139	$152	$152	$165	$199	$206	$206	$206	$2,365	
Internal Retrofit Program	$464	$394	$342	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,200	
Commercial Kitchen Appliance Program	$30	$48	$56	$60	$45	$50	$0	$0	$0	$0	$0	$0	$0	$0	$0	$288	
Commercial Clothes Washers Program	$54	$53	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$0	$0	$127	
Network Energy Management Program	$136	$345	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$481	
CO2 Sensors	$4	$4	$5	$5	$5	$5	$5	$0	$0	$0	$0	$0	$0	$0	$0	$35	
Subtotal	$9,934	$9,640	$8,623	$8,143	$8,041	$7,959	$7,548	$6,141	$6,009	$5,875	$5,795	$5,717	$5,335	$4,548	$2,811	$102,122	40%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
Market Effects																	
Agricultural Heat Pad Program	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$90	
Commercial Parking Lot Controller Program	$237	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$237	
Commercial Rinse & Save Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$243	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$327	0%
INDUSTRIAL																	
Performance Optimization Program	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$41,476	
Subtotal	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$2,765	$41,476	16%
CONSERVATION SUBTOTAL	$17,585	$16,896	$13,621	$12,173	$12,006	$10,950	$10,377	$8,970	$8,838	$8,703	$8,623	$8,546	$8,163	$7,377	$5,640	$158,467	61%
LOAD MANAGEMENT																	
Curtailable Rate Program	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$86,573	
LOAD MANAGEMENT SUBTOTAL	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$5,772	$86,573	34%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	$2,243	$2,094	$1,829	$2,262	$1,329	$1,309	$1,229	$861	$0	$0	$0	$0	$0	$0	$0	$13,155	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	$2,243	$2,094	$1,829	$2,262	$1,329	$1,309	$1,229	$861	$0	$0	$0	$0	$0	$0	$0	$13,155	5%
Subtotal of Programs	$25,599	$24,762	$21,222	$20,206	$19,106	$18,031	$17,377	$15,602	$14,609	$14,475	$14,395	$14,317	$13,935	$13,148	$11,411	$258,195	100%
Program Support	$3,819	$3,765	$3,765	$3,765	$3,765	$3,765	$3,765	$3,765	$3,765	$3,765	$3,765	$3,765	$3,765	$3,765	$3,765	$56,526	
Contingency	$0	$800	$1,200	$1,500	$2,000	$1,755	$1,500	$1,500	$1,500	$1,500	$1,500	$2,000	$2,000	$2,000	$2,000	$22,755	
Total Utility Costs (2012 to 2026)	$29,419	$29,327	$26,186	$25,471	$24,871	$23,551	$22,642	$20,867	$19,874	$19,739	$19,660	$20,082	$19,700	$18,913	$17,176	$337,477	
Total Committed to Date																$395,720	
TOTAL UTILITY COSTS (1989 to 2026)	$29,419	$29,327	$26,186	$25,471	$24,871	$23,551	$22,642	$20,867	$19,874	$19,739	$19,660	$20,082	$19,700	$18,913	$17,176	$733,197	

Note: May not add up due to rounding.

2012/13 PS Plan
Annual Program Administration Costs
(000's in 2012 $)

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	Cumulative Total	
RESIDENTIAL																	
Incentive Based																	
Home Insulation Program	$508	$480	$478	$470	$462	$163	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,561	
Water and Energy Saver Program	$624	$624	$624	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,871	
Lower Income Energy Efficiency Program	$123	$123	$123	$86	$86	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$541	
Refrigerator Retirement Program	$1,739	$1,678	$58	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,475	
Subtotal	$2,994	$2,904	$1,283	$557	$548	$163	$0	$0	$0	$0	$0	$0	$0	$0	$0	$8,449	13%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Residential Earth Power Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Power Smart PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
COMMERCIAL																	
Commercial Lighting Program	$1,813	$1,789	$1,789	$1,789	$1,784	$1,784	$1,784	$1,784	$1,784	$1,784	$1,784	$1,784	$1,784	$1,784	$102	$25,125	
Commercial Custom Measures Program	$75	$75	$75	$75	$75	$75	$75	$75	$75	$75	$75	$75	$75	$75	$75	$1,123	
Commercial Windows Program	$215	$215	$215	$215	$215	$215	$215	$215	$215	$215	$215	$215	$215	$215	$215	$3,232	
Commercial HVAC Program - Chiller	$18	$16	$15	$14	$12	$11	$0	$0	$0	$0	$0	$0	$0	$0	$0	$86	
City of Winnipeg Power Smart Agreement	$2	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2	
Commercial Refrigeration Program	$159	$159	$113	$113	$113	$113	$113	$113	$113	$113	$113	$113	$113	$0	$0	$1,564	
Commercial Insulation Program	$191	$191	$191	$191	$191	$191	$191	$191	$191	$191	$191	$191	$191	$191	$191	$2,864	
Commercial Earth Power Program	$115	$115	$115	$115	$115	$115	$115	$115	$115	$115	$115	$115	$115	$115	$115	$1,721	
New Buildings Program	$218	$218	$218	$218	$218	$218	$218	$0	$0	$0	$0	$0	$0	$0	$0	$1,529	
Commercial Building Optimization Program	$31	$31	$31	$31	$31	$31	$31	$31	$31	$31	$31	$31	$31	$31	$31	$471	
Internal Retrofit Program	$464	$394	$342	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,200	
Commercial Kitchen Appliance Program	$8	$8	$8	$8	$5	$5	$0	$0	$0	$0	$0	$0	$0	$0	$0	$42	
Commercial Clothes Washers Program	$19	$19	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$2	$0	$0	$59	
Network Energy Management Program	$23	$23	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$47	
CO2 Sensors	$3	$3	$3	$2	$2	$2	$2	$0	$0	$0	$0	$0	$0	$0	$0	$20	
Subtotal	$3,356	$3,259	$3,118	$2,775	$2,764	$2,763	$2,747	$2,527	$2,527	$2,527	$2,527	$2,527	$2,527	$2,412	$729	$39,084	60%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
Market Effects																	
Agricultural Heat Pad Program	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$90	
Commercial Parking Lot Controller Program	$16	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$16	
Commercial Rinse & Save Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$22	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$106	0%
INDUSTRIAL																	
Performance Optimization Program	$939	$939	$939	$939	$939	$939	$939	$939	$939	$939	$939	$939	$939	$939	$939	$14,086	
Subtotal	$939	$939	$939	$939	$939	$939	$939	$939	$939	$939	$939	$939	$939	$939	$939	$14,086	22%
CONSERVATION SUBTOTAL	$7,311	$7,108	$5,345	$4,277	$4,258	$3,871	$3,692	$3,472	$3,472	$3,472	$3,472	$3,472	$3,472	$3,357	$1,674	$61,725	95%
LOAD MANAGEMENT																	
Curtailable Rate Program	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$90	
LOAD MANAGEMENT SUBTOTAL	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$6	$90	0%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	$1,095	$281	$280	$332	$288	$268	$247	$197	$0	$0	$0	$0	$0	$0	$0	$2,988	
	$1,095	$281	$280	$332	$288	$268	$247	$197	$0	$0	$0	$0	$0	$0	$0	$2,988	5%
Subtotal of Programs	$8,412	$7,396	$5,631	$4,615	$4,552	$4,145	$3,945	$3,675	$3,478	$3,478	$3,478	$3,478	$3,478	$3,363	$1,680	$64,804	100%
Program Support	$3,819	$3,765	$3,765	$3,765	$3,765	$3,765	$3,765	$3,765	$3,765	$3,765	$3,765	$3,765	$3,765	$3,765	$3,765	$56,526	
Contingency	$0	$800	$1,200	$1,500	$2,000	$1,755	$1,500	$1,500	$1,500	$1,500	$1,500	$2,000	$2,000	$2,000	$2,000	$22,755	
Total Administration Costs (2012 to 2026)	$12,231	$11,961	$10,596	$9,879	$10,317	$9,665	$9,209	$8,939	$8,743	$8,743	$8,743	$9,243	$9,243	$9,128	$7,445	$79,282	
Total Committed to Date																$180,707	
TOTAL ADMINISTRATION COSTS (1989 to 2026)	$12,231	$11,961	$10,596	$9,879	$10,317	$9,665	$9,209	$8,939	$8,743	$8,743	$8,743	$9,243	$9,243	$9,128	$7,445	$259,989	

Note: May not add up due to rounding.

2012/13 PS Plan
Annual Program Incentives Costs
(000's in 2012 $)

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	Cumulative Total	
RESIDENTIAL																	
Incentive Based																	
Home Insulation Program	$739	$687	$609	$540	$496	$57	$57	$57	$57	$57	$57	$57	$57	$57	$57	$3,645	
Water and Energy Saver Program	$160	$160	$160	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$481	
Lower Income Energy Efficiency Program	$205	$189	$174	$161	$150	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$880	
Refrigerator Retirement Program	$544	$544	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,088	
Subtotal	$1,649	$1,581	$944	$701	$645	$57	$57	$57	$57	$57	$57	$57	$57	$57	$57	$6,093	3%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Residential Earth Power Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Power Smart PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
COMMERCIAL																	
Commercial Lighting Program	$4,359	$4,199	$3,594	$3,393	$3,208	$3,031	$2,871	$2,714	$2,568	$2,425	$2,296	$2,166	$1,751	$1,421	$1,372	$41,368	
Commercial Custom Measures Program	$172	$186	$185	$185	$184	$193	$192	$191	$191	$190	$199	$198	$197	$196	$195	$2,855	
Commercial Windows Program	$276	$221	$180	$76	$70	$65	$61	$57	$55	$53	$51	$49	$48	$48	$47	$1,357	
Commercial HVAC Program - Chiller	$188	$200	$213	$225	$238	$251	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,316	
City of Winnipeg Power Smart Agreement	$26	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$26	
Commercial Refrigeration Program	$135	$143	$157	$165	$177	$191	$202	$219	$235	$255	$277	$303	$336	$0	$0	$2,797	
Commercial Insulation Program	$340	$288	$246	$197	$167	$144	$114	$99	$88	$78	$71	$65	$60	$56	$53	$2,066	
Commercial Earth Power Program	$213	$238	$238	$238	$226	$226	$226	$226	$226	$226	$241	$241	$241	$241	$241	$3,486	
New Buildings Program	$617	$423	$556	$734	$829	$926	$1,025	$0	$0	$0	$0	$0	$0	$0	$0	$5,110	
Commercial Building Optimization Program	$81	$87	$87	$101	$135	$121	$107	$107	$121	$121	$134	$168	$174	$174	$174	$1,895	
Internal Retrofit Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Commercial Kitchen Appliance Program	$22	$40	$48	$52	$40	$45	$0	$0	$0	$0	$0	$0	$0	$0	$0	$246	
Commercial Clothes Washers Program	$35	$33	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$68	
Network Energy Management Program	$113	$322	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$434	
CO2 Sensors	$1	$2	$2	$2	$3	$3	$3	$0	$0	$0	$0	$0	$0	$0	$0	$16	
Subtotal	$6,579	$6,382	$5,505	$5,369	$5,277	$5,196	$4,801	$3,614	$3,482	$3,348	$3,268	$3,190	$2,808	$2,136	$2,082	$63,038	33%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
Market Effects																	
Agricultural Heat Pad Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Commercial Parking Lot Controller Program	$221	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$221	
Commercial Rinse & Save Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$221	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$221	0%
INDUSTRIAL																	
Performance Optimization Program	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$27,390	
Subtotal	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$1,826	$27,390	14%
CONSERVATION SUBTOTAL	$10,274	$9,788	$8,275	$7,896	$7,748	$7,079	$6,685	$5,497	$5,366	$5,231	$5,151	$5,074	$4,691	$4,020	$3,965	$96,742	50%
LOAD MANAGEMENT																	
Curtailable Rate Program	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$86,483	
LOAD MANAGEMENT SUBTOTAL	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$5,766	$86,483	45%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
Bioenergy Optimization Program	$1,147	$1,812	$1,549	$1,930	$1,041	$1,041	$982	$664	$0	$0	$0	$0	$0	$0	$0	$10,166	
	$1,147	$1,812	$1,549	$1,930	$1,041	$1,041	$982	$664	$0	$0	$0	$0	$0	$0	$0	$10,166	5%
Total Incentive Costs (2012 to 2026)	$17,187	$17,366	$15,590	$15,591	$14,555	$13,886	$13,432	$11,927	$11,131	$10,996	$10,917	$10,839	$10,457	$9,785	$9,731	$193,391	100%
Total Committed to Date																$213,708	
TOTAL INCENTIVE COSTS (1989 to 2026)	$17,187	$17,366	$15,590	$15,591	$14,555	$13,886	$13,432	$11,927	$11,131	$10,996	$10,917	$10,839	$10,457	$9,785	$9,731	$407,100	

Note: May not add up due to rounding.

APPENDIX B – HISTORICAL ELECTRIC SAVINGS & COSTS

APPENDIX B.1 - ANNUAL CAPACITY SAVINGS (MW)

APPENDIX B.2 - ANNUAL ENERGY SAVINGS (GW.H)

APPENDIX B.3 - ANNUAL UTILITY COSTS

APPENDIX B.4 - ANNUAL PROGRAM ADMINISTRATION COSTS

APPENDIX B.5 - ANNUAL PROGRAM INCENTIVE COSTS

PUB/MH I-59b
Attachment 2
Page 123 of 149

2012/13 PS Plan
Annual Capacity Savings (MW)
(Savings to Date)
(1989/90 - 2011/12)

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	Interim Estimate 2011/12	Benchmark 2026/27	At Generation 2026/27
RESIDENTIAL																									
Incentive Based																									
Home Insulation Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.83	2.03	5.16	7.96	10.69	13.77	16.38	18.92	18.92	21.57
Lower Income Energy Efficiency Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.36	0.70	1.54	2.92	1.35	1.53
New Home Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.19	0.44	0.73	0.97	1.18	1.46	1.56	1.56	1.77
Refrigerator Retirement Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.66	0.00	0.00
Water and Energy Saver Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.70	1.24	0.00	0.00
Subtotal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.86	2.22	5.60	8.81	12.01	15.65	20.08	25.30	21.82	24.88
Customer Service Initiatives																									
Power Smart Residential Loan Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.47	0.80	1.10	1.39	1.64	2.00	2.73	3.04	3.93	4.22	4.38	4.38	5.00
Residential Earth Power Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.25	0.63	1.06	1.42	2.07	2.47	2.99	3.28	3.43	2.44	2.78
ecoEnergy	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Solar H2O Heater	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.47	0.89	1.35	2.02	2.70	3.42	4.80	5.51	6.92	7.50	7.81	6.82	7.78
DISCONTINUED/COMPLETED																									
Appliances	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.49	1.01	1.59	1.71	1.71	1.71	0.04	0.04
Seasonal LED Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.12	0.17	0.20	0.21	0.21	0.21	0.09	0.10
Outdoor Timer	0.29	0.52	0.90	1.23	1.51	1.86	1.99	2.28	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.39	2.72
Res Hot Water	0.00	0.00	0.06	0.06	0.06	0.06	0.06	0.07	0.07	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.08	0.09
Water Heater Rental	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05
Thermostat	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.04	0.04	0.04	0.04	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retrofit/Demonstration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RBB	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
High Efficiency Furnace & Boiler	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.43	0.43	0.43	0.43	0.49
Energy Efficient Light Fixtures	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.21	0.33	0.43	0.59	0.69	0.29	0.34
Compact Fluorescent Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.64	3.11	4.15	5.69	10.18	17.72	21.33	20.06	0.00	0.00
Power Smart Energy Manager	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.09	0.10	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.14	0.00	0.00
R2000 House	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.06
Subtotal	0.29	0.52	0.96	1.30	1.57	1.92	2.06	2.36	2.51	2.55	2.56	2.56	2.64	2.70	2.67	4.35	5.87	7.52	9.79	15.00	23.21	26.98	25.80	3.41	3.88
RESIDENTIAL TOTAL	0.29	0.52	0.96	1.30	1.57	1.92	2.06	2.36	2.51	2.55	2.56	2.56	3.11	3.58	4.02	7.22	10.79	16.54	23.40	32.52	45.78	54.55	58.92	32.05	36.54
COMMERCIAL																									
Commercial Lighting Program	0.00	0.00	0.00	0.50	2.59	5.72	9.17	10.78	11.57	15.14	16.37	17.35	18.54	19.65	21.68	24.22	27.65	31.14	34.05	38.51	42.30	45.75	51.03	46.14	52.60
Commercial Earth Power Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15	0.80	1.11	1.48	1.66	1.97	2.42	3.77	4.21	5.36	7.42	8.67	9.28	10.31	11.25	11.84	10.60	12.09
Commercial Insulation Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15	0.75	1.84	3.17	4.85	6.22	6.22	7.09
Commercial Windows Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.17	0.26	0.31	0.39	0.45	0.62	0.82	1.05	1.49	1.66	1.76	2.09	2.97	3.99	5.07	4.84	5.51
Internal Retrofit Program	0.00	0.00	0.00	0.04	0.33	0.56	0.65	0.74	0.87	1.03	1.10	1.22	1.26	1.36	1.69	2.16	2.41	2.83	3.00	3.24	3.54	4.04	8.17	8.16	9.31
Commercial Custom Measures Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.05	0.11	0.44	0.52	0.52	0.52	0.87	0.87	0.91	0.98	1.15	1.22	1.22	1.39	1.65	1.65	1.89
Commercial Refrigeration Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.14	0.84	1.34	1.63	1.92	2.14	0.84	0.95
Commercial HVAC Program - Chiller	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.04	0.04
City of Winnipeg Power Smart Agreement	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.13	0.27	1.61	2.00	2.14	2.20	2.38	2.48	2.60	0.26	0.29
Commercial Clothes Washers Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.24	0.28	0.36	0.00	0.00
Commercial Kitchen Appliance Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.05	0.11	0.14	0.16	0.00	0.00
Power Smart Shops	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.14	0.14	0.00	0.00
Commercial Building Optimization Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03	0.00	0.00
Network Energy Management Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
New Buildings Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.34	0.34	0.39
CO2 Sensors	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Power Smart Energy Manager Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00	0.00	0.00	0.54	2.92	6.28	9.82	11.78	13.45	17.64	19.70	21.14	22.74	24.60	28.97	32.79	39.43	46.33	52.36	59.79	67.94	76.25	89.79	79.09	90.17
DISCONTINUED/COMPLETED																									
Commercial Showerhead	0.00	0.00	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.23
Infrared Heat Lamp	0.00	0.00	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.69
Livestock Waterer	0.00	0.00	0.00	0.00	0.00	0.05	0.08	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.00	0.00
Roadway Lighting	0.00	0.00	0.91	3.13	5.37	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	7.94
Sentinel Lighting	0.00	0.00	0.51	1.11	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	1.78	2.03
Commercial Air Barrier	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.07	0.08	0.11	0.17	0.20	0.23	0.26	0.28	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.33
Agricultural Demand Controller	0.00	0.00	0.00	0.68	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.03	1.00	1.00	1.00	1.00	1.00	1.14
Commercial Air Conditioning	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Aboriginal Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Parking Lot Controllers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Spray Valves	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.22	0.27	0.27	0.27	0.00	0.00
Agricultural Heat Pads	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.66	1.00	1.19	1.59	1.99	2.20	2.61	2.71	2.77	3.24	3.49	3.59	3.87	3.87	2.98	3.39
Subtotal	0.00	0.00	2.23	5.74	9.00	10.64	10.68	10.75	10.76	11.43	11.80	12.05	12.49	12.91	13.16	13.58	13.69	13.75	14.23	14.66	14.81	15.09	15.09	13.83	15.77
COMMERCIAL TOTAL	0.00	0.00	2.23	6.28	11.92	16.92	20.49	22.54	24.21	29.08	31.50	33.18	35.23	37.51	42.12	46.37	53.12	60.08	66.59	74.45	82.75	91.34	104.88	92.92	105.93
INDUSTRIAL																									
Performance Optimization Program	0.00	0.00	0.00	0.00	0.00	0.29	1.08	4.60	5.78	37.36	39.13	39.45	48.40	52.93	54.07	57.64	61.68	63.18	66.25	68.71	72.03	75.49	78.95	64.93	71.42
Emergency Preparedness Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00	0.00	0.00	0.00	0.00	0.29	1.08	4.60	5.78	37.36	39.13	39.45	48.40	52.93	54.07	57.64	61.68	63.18	66.25	68.71	72.03	75.49	78.95	64.93	71.42
DISCONTINUED/COMPLETED																									
Industrial (Basic)	0.00	0.00	0.00	0.00	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.00	0.00
Retrofit/Demonstration GSL	0.00	0.00	0.00	0.31	0.38	1.59	4.30	4.30	4.30	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.34	4.16	4.58
High Efficiency Motors	0.00	0.00	0.07	0.73	1.33	1.81	2.30	3.03	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	3.79	4.17
Efficient Motors (QMR)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00	0.00	0.07	1.04	1.74	3.43	6.63	7.36	8.12	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	8.16	7.95	8.74
INDUSTRIAL TOTAL	0.00	0.00	0.07	1.04	1.74	3.72	7.71	11.96	13.90	45.52	47.29	47.61	56.56	61.09	62.23	65.80	69.84	71.34	74.41	76.87	80.19	83.65	87.11	72.87	80.16
EFFICIENCY PROGRAMS SUBTOTAL	0.29	0.52	3.27	8.62	15.24	22.56	30.26	36.85	40.63	77.14	81.35	83.36	94.90	102.19	108.38	119.39	133.75	147.96	164.39	183.85	208.72	229.55	250.91	197.85	222.63
CUSTOMER SELF-GENERATION PROGRAMS																									
BioEnergy Optimization Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.30	14.30	14.30	14.30	14.30	14.30	14.35	0.00	0.00
RATE/LOAD MANAGEMENT PROGRAMS																									
Curtailable Rate Program	0.00	0.00	0.00	0.00	40.70	46.40	24.70	32.70	80.00	48.20	58.00	57.10	68.00	110.28	148.54	153.76	189.07	183.29	180.62	172.76	149.15	154.52	148.59	0.00	0.00
PROGRAM IMPACTS	0.29	0.52	3.27	8.62	55.94	68.96	54.96	69.55	120.63	125.34	139.35	140.46	162.90	212.47	256.91	273.15	337.12	345.55	359.31	370.90	372.17	398.36	413.85	197.85	222.63
CODES, STANDARDS & REGULATIONS	0.00	0.00	0.00	0.48	1.60	3.33	5.43	8.41	13.60	20.40	28.00	35.18	42.93	52.01	56.15	61.78	66.95	72.42	78.60	85.12	92.02	99.48	108.37	108.37	123.43
Total Impact @ Meter	0.29	0.52	3.27	9.10	57.54	72.29	60.38	77.97	134.22	145.74	167.35	175.64	205.83	264.48	313.06	334.93	404.07	417.97	437.91	456.03	464.18	497.85	522.22	306.22	
Total Impact @ Generation	0.33	0.59	3.72	10.33	63.90	80.40	67.54	87.09	149.25	162.37	186.53	195.99	229.61	294.58	348.38	372.95	449.61	465.62	488.33	509.21	519.31	557.34	585.22	346.07	346.07

Note: May not add up due to rounding.

PUB/MH I-59b
Attachment 2
Page 124 of 149

2012/13 PS Plan
Annual Energy Savings (GW.h)
(Savings To Date)
(1989/90 - 2011/12)

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	Interim Estimate 2011/12	Benchmark 2026/27	At Generation 2026/27
RESIDENTIAL																									
Incentive Based																									
Home Insulation Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.74	4.25	10.74	16.49	22.08	28.41	33.75	38.67	38.67	44.08
Lower Income Energy Efficiency Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.55	1.10	1.96	4.23	6.88	2.92	3.32
New Home Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.63	1.86	2.87	3.68	4.27	5.04	5.50	5.50	6.27
Refrigerator Retirement Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.02	0.00	0.00
Water and Energy Saver Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.30	10.54	0.00	0.00
Subtotal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.83	4.88	12.60	19.92	26.87	34.64	48.32	69.61	47.08	53.68
Customer Service Initiatives																									
Power Smart Residential Loan Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.91	1.56	2.16	2.73	3.21	3.86	4.60	5.22	6.87	7.42	7.74	7.74	8.83
Residential Earth Power Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.34	0.99	2.83	4.78	6.14	8.79	10.17	11.22	11.82	12.12	5.98	6.82
ecoEnergy	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.12	0.30	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.86
Solar H2O Heater	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.05	0.05	0.05	0.06
Subtotal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.91	2.02	3.44	6.31	8.75	10.76	14.15	16.15	18.88	20.05	20.67	14.53	16.57
DISCONTINUED/COMPLETED																									
Appliances	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.55	7.60	12.07	12.75	12.75	12.75	0.42	0.48
Seasonal LED Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	1.34	2.30	3.07	3.23	3.23	3.23	1.89	2.15
Outdoor Timer	5.01	8.93	15.34	20.59	24.78	29.22	30.89	34.68	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	36.48	41.58
Res Hot Water	0.00	0.00	0.35	0.35	0.35	0.35	0.35	0.36	0.46	0.59	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.61	0.47	0.54
Water Heater Rental	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.25	0.42	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.48	0.55
Thermostat	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.23	0.36	0.36	0.36	0.36	0.36	0.36	0.41
Retrofit/Demonstration	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
RBB	0.00	0.00	0.02	0.02	0.02	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
High Efficiency Furnace & Boiler	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.26	1.26	1.26	1.26	1.44
Energy Efficient Light Fixtures	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20	1.03	2.08	2.64	3.68	4.35	1.82	2.08
Compact Fluorescent Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.09	15.39	20.60	28.09	49.94	77.72	92.07	86.89	0.00	0.00
Power Smart Energy Manager	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.62	1.20	2.38	2.80	2.80	2.80	2.80	2.80	2.80	2.80	2.18	0.00	0.00
R2000 House	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.10	0.15	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.22
Subtotal	5.01	8.93	15.70	20.96	25.15	29.59	31.26	35.12	37.20	37.49	37.58	37.58	38.30	38.93	40.15	48.66	56.04	66.50	79.95	108.10	138.52	153.91	148.79	43.38	49.45
RESIDENTIAL TOTAL	5.01	8.93	15.70	20.96	25.15	29.59	31.26	35.12	37.20	37.49	37.58	37.58	39.21	40.96	43.59	56.80	69.67	89.87	114.02	151.11	192.05	222.28	239.07	105.00	119.70
COMMERCIAL																									
Commercial Lighting Program	0.00	0.00	0.00	2.92	16.99	35.90	55.00	61.23	67.45	85.39	90.76	94.88	100.18	105.59	116.21	132.57	153.14	175.81	193.92	218.90	239.47	258.75	283.92	260.64	297.13
Commercial Earth Power Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.28	1.12	1.79	2.86	3.23	4.02	5.05	7.76	8.75	11.12	15.30	18.63	20.21	23.61	25.99	27.59	24.99	28.48
Commercial Insulation Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.60	1.87	4.07	6.55	9.73	12.49	12.49	14.24
Commercial Windows Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.15	0.35	0.56	0.67	0.89	1.02	1.37	1.79	2.29	3.19	3.95	4.46	5.23	7.29	9.67	12.47	11.76	13.41
Internal Retrofit Program	0.00	0.00	0.00	0.17	1.23	2.73	3.29	3.77	4.26	4.95	5.44	5.85	6.14	6.89	9.38	12.15	14.42	16.98	18.03	19.82	21.47	24.05	35.32	34.74	39.60
Commercial Custom Measures Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.38	0.38	2.58	10.00	10.75	11.70	12.16	12.77	12.83	12.85	13.14	15.39	15.91	17.36	18.82	20.11	18.78	21.41
Commercial Refrigeration Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.22	3.05	4.26	5.53	6.97	8.85	3.45	3.93
Commercial HVAC Program - Chiller	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.46	3.66	4.10	4.28	4.85	5.34	7.10	8.28	8.28	9.43
City of Winnipeg Power Smart Agreement	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.63	1.17	7.61	9.60	10.12	10.34	10.83	11.15	11.57	1.13	1.29
Commercial Clothes Washers Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.32	0.38	0.47	0.00	0.00
Commercial Kitchen Appliance Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.47	0.60	0.71	0.00	0.00
Power Smart Shops	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.26	0.69	0.69	0.00	0.00
Commercial Building Optimization Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.47	0.62	0.88	0.88	0.00	0.00
Network Energy Management Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.18	0.18	0.00	0.00
New Buildings Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.70	1.70	1.94
CO2 Sensors	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.11	0.00	0.00
Power Smart Energy Manager Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00	0.00	0.00	3.09	18.23	38.63	58.29	65.81	73.56	95.27	109.74	115.61	123.06	131.13	148.53	172.23	205.99	240.70	269.74	304.26	339.17	374.99	425.33	377.96	430.87
DISCONTINUED/COMPLETED																									
Commercial Showerhead	0.00	0.00	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.64
Infrared Heat Lamp	0.00	0.00	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	3.72	4.24
Livestock Waterer	0.00	0.00	0.00	0.00	0.00	0.17	0.31	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.37	0.00	0.00
Roadway Lighting	0.00	0.00	3.88	13.50	23.16	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	29.85	34.03
Sentinel Lighting	0.00	0.00	2.25	4.73	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	7.50	8.55
Commercial Air Barrier	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.16	0.18	0.20	0.28	0.45	0.55	0.63	0.72	0.75	0.78	0.78	0.83	0.83	0.83	0.83	0.83	0.83	0.95
Agricultural Demand Controller	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial Air Conditioning	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.04	0.20	0.20	0.29	0.31	0.31	0.31	0.31	0.31	0.31	0.31	0.28	0.32
Aboriginal Commercial	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Parking Lot Controllers	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.76	1.62	3.67	4.10	4.40	5.94	6.76	8.80	11.50	19.96	27.93	30.46	32.43	34.88	38.11	39.38	21.64	24.67
Spray Valves	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.90	2.88	4.79	5.17	5.17	5.17	0.00	0.00
Agricultural Heat Pads	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.51	5.51	6.68	9.23	11.59	12.90	15.39	16.39	17.03	21.75	24.30	25.41	28.37	28.37	19.01	21.67
Subtotal	0.00	0.00	11.30	23.39	35.82	42.68	42.83	43.81	44.70	50.27	52.79	54.41	58.64	62.06	65.51	70.82	80.32	90.84	99.12	105.55	109.49	115.68	116.95	84.28	96.07
COMMERCIAL TOTAL	0.00	0.00	11.30	26.48	54.04	81.31	101.11	109.62	118.26	145.55	162.53	170.02	181.70	193.19	214.04	243.05	286.31	331.54	368.87	409.81	448.66	490.67	542.28	462.23	526.95
INDUSTRIAL																									
Performance Optimization Program	0.00	0.00	0.00	0.00	0.00	2.42	7.21	35.10	43.52	85.88	107.70	110.85	142.93	170.52	181.46	207.61	238.59	249.35	276.39	294.86	319.61	347.88	373.07	256.06	281.67
Emergency Preparedness Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00	0.00	0.00	0.00	0.00	2.42	7.21	35.10	43.52	85.88	107.70	110.85	142.93	170.52	181.46	207.61	238.59	249.35	276.39	294.86	319.61	347.88	373.07	256.06	281.67
DISCONTINUED/COMPLETED																									
Industrial (Basic)	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00
Retrofit/Demonstration GSL	0.00	0.00	0.00	0.07	0.67	9.67	32.72	32.72	32.72	33.07	33.07	33.07	33.07	33.07	33.07	33.07	33.07	33.07	32.99	32.99	32.99	32.99	32.99	32.98	36.28
High Efficiency Motors	0.00	0.00	0.40	4.79	7.65	10.34	13.30	17.88	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	21.48	23.63
Efficient Motors (QMR)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	0.00	0.00	0.40	4.87	8.33	20.02	46.02	50.61	54.21	54.56	54.56	54.56	54.56	54.56	54.56	54.56	54.56	54.56	54.48	54.48	54.48	54.48	54.48	54.46	59.91
INDUSTRIAL TOTAL	0.00	0.00	0.40	4.87	8.33	22.44	53.23	85.71	97.73	140.44	162.25	165.41	197.49	225.08	236.02	262.17	293.15	303.90	330.87	349.35	374.10	402.37	427.55	310.53	341.58
EFFICIENCY PROGRAMS SUBTOTAL	5.01	8.93	27.40	52.31	87.52	133.34	185.60	230.45	253.19	323.48	362.36	373.01	418.39	459.23	493.64	562.03	649.13	725.32	813.76	910.27	1,014.81	1,115.32	1,208.91	877.76	988.22
CUSTOMER SELF-GENERATION PROGRAMS																									
BioEnergy Optimization Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.26	120.06	84.21	94.01	80.08	86.56	70.27	0.00	0.00
RATE/LOAD MANAGEMENT PROGRAMS																									
Curtailable Rate Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PROGRAM IMPACTS	5.01	8.93	27.40	52.31	87.52	133.34	185.60	230.45	253.19	323.48	362.36	373.01	418.39	459.23	493.64	562.03	659.39	845.38	897.97	1,004.28	1,094.89	1,201.88	1,279.18	877.76	988.22
CODES, STANDARDS & REGULATIONS	0.00	0.00	0.00	1.94	6.59	13.73	22.35	35.19	55.52	81.51	110.09	137.26	166.49	200.72	217.58	240.50	261.85	284.34	309.12	335.24	377.80	422.85	472.78	472.78	538.31
Total Impact @ Meter	5.01	8.93	27.40	54.25	94.11	147.07	207.95	265.64	308.71	404.98	472.45	510.27	584.89	659.94	711.22	802.53	921.24	1,129.72	1,207.10	1,339.52	1,472.69	1,624.73	1,751.96	1,350.53	
Total Impact @ Generation	5.71	10.18	31.22	61.64	106.95	166.77	234.93	299.40	347.96	455.93	531.90	574.83	658.55	742.94	800.89	903.87	1,037.49	1,270.27	1,358.84	1,508.67	1,660.05	1,831.98	1,976.67	1,526.54	1,526.54

Note: May not add up due to rounding.

PUB/MH I-59b
Attachment 2
Page 125 of 149

2012/13 PS Plan
Annual Utility Costs
(1989/90 - 2011/12)
(000's in 2012 $)

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	Interim Estimate 2011/12	Cumulative 2011/12
RESIDENTIAL																								
Home Insulation Program	0	0	0	0	260	397	248	231	417	46	5	47	74	73	142	783	1,165	1,988	1,603	1,772	1,760	1,420	1,281	13,711
Lower Income Energy Efficiency Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	45	107	221	222	117	196	99	1,006
New Home Program	0	0	0	40	156	98	223	126	65	34	1	19	136	301	230	315	631	943	677	672	604	218	254	5,744
Refrigerator Retirement Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12	83	1,509	1,604
Earth Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	0	6
Water and Energy Saver Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	19	0	0	83	52	476	448	1,078
Subtotal	0	0	0	40	416	496	471	358	482	80	6	66	210	374	373	1,097	1,860	3,038	2,501	2,748	2,544	2,399	3,590	23,148
Customer Service Initiatives																								
Power Smart Residential Loan Program	0	0	0	0	0	0	0	0	0	0	0	47	80	21	9	0	1	10	-1	-6	-77	-38	-29	16
Residential Earth Power Program	0	0	0	0	0	0	0	0	0	0	0	0	2	49	101	361	916	-97	74	217	169	107	0	1,900
ecoEnergy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-11	-44	74	171	-20	149	105	115	539
Solar H2O Heater	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7	0	0	7
Subtotal	0	0	0	0	0	0	0	0	0	0	0	47	82	70	111	350	873	-13	244	191	248	173	85	2,462
DISCONTINUED/COMPLETED																								
Appliances	0	0	0	0	0	0	0	0	0	0	0	0	0	21	14	11	100	1,609	2,046	1,819	417	12	1	6,051
Seasonal LED Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	88	407	379	359	24	0	0	1,258
Outdoor Timer	203	296	253	197	97	56	20	3	10	4	1	0	0	0	0	0	0	0	0	0	0	0	0	1,140
Res Hot Water	0	0	180	0	0	0	2	63	26	16	4	0	0	0	0	0	0	0	0	0	0	0	0	291
Water Heater Rental	0	0	0	0	0	0	19	409	405	77	5	0	0	0	0	0	0	0	0	0	0	0	0	915
Thermostat	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9	4	8	73	36	10	0	0	0	141
Retrofit/Demonstration	0	67	28	125	0	0	4	0	0	0	0	0	0	0	0	14	48	0	0	0	0	0	0	286
RBB	0	0	54	13	0	0	0	0	0	0	0	0	0	17	29	5	69	26	0	0	0	0	0	212
High Efficiency Furnace & Boiler	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	3
Energy Efficient Light Fixtures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	162	520	402	194	253	307	1,838
Aboriginal Programs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	15	0	0	0	0	0	20
Compact Fluorescent Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	21	824	1,066	853	976	1,345	1,659	1,044	2	7,790
Subtotal	203	363	514	335	97	56	45	476	441	97	10	0	0	38	74	858	1,387	3,145	3,958	3,936	2,294	1,309	310	19,945
Exploratory Programs																								
Exploratory Programs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	21	4	0	25
RESIDENTIAL TOTAL	203	363	514	375	513	552	516	833	922	177	15	112	292	482	558	2,305	4,120	6,170	6,702	6,875	5,107	3,886	3,986	45,580
COMMERCIAL																								
Commercial Lighting Program	0	0	112	1,189	2,549	3,008	2,951	1,226	1,043	2,065	921	675	1,046	1,240	2,798	5,513	6,649	7,623	7,878	8,172	7,622	6,918	6,463	77,660
Commercial Earth Power Program	0	0	0	0	15	50	81	68	230	120	137	113	173	294	662	284	532	659	372	234	402	310	296	5,032
Commercial Insulation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	225	270	251	240	270	237	1,493
Commercial Windows Program	0	0	0	0	8	27	43	131	174	64	45	78	69	160	124	250	332	412	402	467	1,059	1,263	1,005	6,112
Internal Retrofit Program	0	0	120	285	477	575	166	216	178	235	116	299	141	291	640	729	621	8,844	8,503	4,611	3,222	1,923	759	32,954
Commercial Custom Measures Program	0	0	0	0	20	68	109	81	0	224	543	135	151	84	162	12	8	125	198	252	221	240	242	2,874
Commercial Refrigeration Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	245	325	310	184	192	177	341	1,774
Commercial HVAC Program - Chiller	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	184	213	75	224	169	326	212	1,401
City of Winnipeg Power Smart Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0	4	2,955	2,026	4,844	1,916	211	66	47	83	-45	12,107
Commercial Clothes Washers Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	58	45	143	67	64	377
Commercial Kitchen Appliance Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	95	86	37	32	251
Power Smart Shops	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	64	254	148	47	513
Commercial Building Optimization Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	190	61	42	29	27	38	40	427
Network Energy Management Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	21	71	86	24	205
New Buildings Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	147	101	170	301	342	1,062
CO2 Sensors	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	2	4
Power Smart Energy Manager Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	84	122	91	68	22	388
Subtotal	0	0	232	1,475	3,069	3,727	3,351	1,722	1,625	2,707	1,762	1,300	1,582	2,072	7,340	8,814	13,605	20,405	18,554	14,940	14,017	12,256	10,081	144,636
DISCONTINUED/COMPLETED																								
Commercial Showerhead	0	67	123	36	4	124	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	353
Infrared Heat Lamp	0	18	294	34	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	352
Livestock Waterer	0	0	0	0	0	158	136	95	24	4	0	0	0	0	0	0	0	0	0	0	0	0	0	418
Roadway Lighting	0	116	1,531	2,160	1,972	1,498	18	0	48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7,343
Sentinel Lighting	0	33	1,350	1,131	1,160	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,673
Commercial Air Barrier	0	0	0	0	8	29	46	101	80	3	11	34	22	18	19	7	4	0	6	0	0	0	0	388
Agricultural Demand Controller	0	0	33	645	219	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	897
Commercial Air Conditioning	0	0	0	0	1	2	3	82	78	0	0	0	7	55	0	142	11	0	0	0	0	0	0	380
Aboriginal Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
Parking Lot Controllers	0	0	0	0	40	136	219	116	104	196	21	53	210	114	297	375	1,113	961	617	399	534	551	287	6,344
Spray Valves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	40	29	23	9	5	0	107
Agricultural Heat Pads	0	0	0	0	0	0	3	70	36	93	93	49	62	70	62	134	76	69	63	45	121	103	8	1,157
Subtotal	0	233	3,331	4,004	3,410	1,946	425	464	370	296	125	137	301	258	379	658	1,205	1,070	716	468	664	659	295	21,413
	0	233	3,563	5,479	6,479	5,673	3,776	2,186	1,995	3,003	1,887	1,437	1,883	2,330	7,719	9,472	14,809	21,476	19,269	15,407	14,681	12,915	10,376	166,048
INDUSTRIAL																								
Performance Optimization Program	0	0	90	192	246	506	513	462	673	408	271	418	1,057	3,339	1,255	1,701	1,774	1,138	3,402	2,650	3,058	2,880	2,991	29,021
Emergency Preparedness Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	86	73	7	1	167
Subtotal	0	0	90	192	246	506	513	462	673	408	271	418	1,057	3,339	1,255	1,701	1,774	1,138	3,402	2,735	3,131	2,887	2,992	29,188
DISCONTINUED/COMPLETED																								
Industrial (Basic)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofit/Demonstration GSL	0	0	65	327	350	630	1,082	366	337	87	11	5	0	0	0	0	0	39	0	0	0	0	0	3,300
High Efficiency Motors	0	23	319	773	619	492	451	489	658	48	3	0	0	0	0	0	0	0	0	0	0	0	0	3,875
Efficient Motors (QMR)	0	0	0	23	54	20	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	101
Subtotal	0	23	383	1,124	1,023	1,142	1,537	855	995	134	15	5	0	0	0	0	0	39	0	0	0	0	0	7,276
	0	23	473	1,316	1,269	1,648	2,050	1,317	1,667	542	285	423	1,057	3,339	1,255	1,701	1,774	1,177	3,402	2,736	3,131	2,887	2,992	36,464
EFFICIENCY PROGRAMS SUBTOTAL	203	619	4,550	7,170	8,260	7,874	6,342	4,336	4,585	3,722	2,188	1,972	3,233	6,151	9,531	13,478	20,703	28,823	29,373	25,018	22,919	19,687	17,353	248,092
CUSTOMER SELF-GENERATION PROGRAMS																								
BioEnergy Optimization Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	155	1,792	1,731	1,818	1,563	1,670	1,756	10,485
RATE/LOAD MANAGEMENT PROGRAMS																								
Curtailable Rate Program	0	0	0	88	652	1,600	1,440	1,411	1,221	1,561	1,929	2,474	3,260	4,916	6,438	6,454	7,195	7,039	6,979	6,753	6,060	5,973	5,903	79,349
Support Costs	0	365	3,507	4,214	2,994	1,666	1,979	1,589	1,265	1,641	2,336	3,099	2,702	3,495	3,490	3,409	2,498	2,072	2,007	3,684	3,710	3,223	2,851	57,794
GRAND TOTAL	203	984	8,057	11,472	11,906	11,140	9,760	7,336	7,072	6,924	6,453	7,546	9,195	14,561	19,460	23,341	30,552	39,726	40,090	37,274	34,252	30,553	27,863	395,720

Note: May not add up due to rounding.

PUB/MH I-59b
Attachment 2
Page 126 of 149

2012/13 PS Plan
Annual Program Administration Costs
(1989/90 - 2011/12)
(000's in 2012 $)

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	Interim Estimate 2011/12	Cumulative 2011/12
RESIDENTIAL																								
Home Insulation Program	0	0	0	0	260	397	248	231	417	46	5	47	74	73	142	283	446	300	223	223	197	222	246	4,080
Lower Income Energy Efficiency Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	45	0	179	888	1,221	83	35	2,451
New Home Program	0	0	0	40	156	98	223	126	65	34	1	19	136	301	230	303	561	810	559	565	486	93	209	5,017
Refrigerator Retirement Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	12	83	1,184	1,279
Water and Energy Saver Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	19	0	0	83	52	88	260	502
Subtotal	0	0	0	40	416	496	471	358	482	80	6	66	210	374	373	587	1,071	1,109	961	1,759	1,967	569	1,934	13,329
Customer Service Initiatives																								
Power Smart Residential Loan Program	0	0	0	0	0	0	0	0	0	0	0	47	80	21	9	0	1	10	-1	-6	-77	-38	-29	16
Residential Earth Power Program	0	0	0	0	0	0	0	0	0	0	0	0	2	49	101	361	916	-97	74	217	169	107	0	1,900
ecoEnergy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-11	-44	74	171	-20	149	105	115	539
Solar H2O Heater	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7	0	0	7
Subtotal	0	0	0	0	0	0	0	0	0	0	0	47	82	70	111	350	873	-13	244	191	248	173	85	2,462
DISCONTINUED/COMPLETED																								
Appliances	0	0	0	0	0	0	0	0	0	0	0	0	0	21	14	11	100	587	638	428	113	12	1	1,925
Seasonal LED Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	56	242	261	288	2	0	0	849
Outdoor Timer	153	227	192	162	67	56	20	3	10	4	1	0	0	0	0	0	0	0	0	0	0	0	0	893
Res Hot Water	0	0	170	0	0	0	2	63	26	16	4	0	0	0	0	0	0	0	0	0	0	0	0	281
Water Heater Rental	0	0	0	0	0	0	19	409	405	77	5	0	0	0	0	0	0	0	0	0	0	0	0	915
Thermostat	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9	4	8	51	25	5	0	0	0	102
Retrofit/Demonstration	0	67	28	125	0	0	0	0	0	0	0	0	0	0	0	14	48	0	0	0	0	0	0	281
RBB	0	0	28	13	0	0	0	0	0	0	0	0	0	17	29	5	69	0	0	0	0	0	0	161
High Efficiency Furnace & Boiler	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	0	0	0	3
Energy Efficient Light Fixtures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	64	411	329	128	99	167	1,198
Aboriginal Programs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Compact Fluorescent Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	21	660	791	611	712	660	536	423	12	4,426
Subtotal	153	293	418	299	67	56	41	475	441	97	10	0	0	38	74	694	1,075	1,555	2,047	1,710	780	533	180	11,035
Exploratory Programs																								
Exploratory Programs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	21	0	0	21
RESIDENTIAL TOTAL	153	293	418	339	483	552	511	833	922	177	15	112	292	482	558	1,631	3,019	2,652	3,252	3,661	3,015	1,275	2,200	26,846
COMMERCIAL																								
Commercial Lighting Program	0	0	112	876	976	809	654	447	580	434	319	342	418	847	1,156	1,958	1,907	2,256	2,148	1,934	1,988	1,938	1,879	23,977
Commercial Earth Power Program	0	0	0	0	15	50	81	37	78	28	13	40	82	148	296	152	210	210	223	137	126	101	123	2,151
Commercial Insulation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	148	149	46	46	33	31	453
Commercial Windows Program	0	0	0	0	8	27	43	81	78	8	1	25	13	43	32	63	55	162	169	105	121	123	118	1,276
Internal Retrofit Program	0	0	120	233	209	185	64	69	71	64	46	93	51	107	126	184	198	8,259	8,151	4,409	2,346	176	153	25,314
Commercial Custom Measures Program	0	0	0	0	20	68	109	50	0	93	91	82	99	62	66	9	1	82	35	217	90	93	141	1,407
Commercial Refrigeration Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	245	228	203	99	101	87	137	1,099
Commercial HVAC Program - Chiller	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	74	22	14	13	18	16	16	174
City of Winnipeg Power Smart Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0	4	2,142	1,055	1,012	453	57	66	47	-82	-118	4,637
Commercial Clothes Washers Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	36	40	43	36	154
Commercial Kitchen Appliance Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	48	37	13	18	117
Power Smart Shops	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	64	251	145	47	508
Commercial Building Optimization Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	190	61	42	22	18	28	27	387
Network Energy Management Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	21	67	74	24	186
New Buildings Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	101	170	187	229	686
CO2 Sensors	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	3
Power Smart Energy Manager Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	119	91	113	22	347
Subtotal	0	0	232	1,109	1,228	1,139	951	684	807	627	470	582	663	1,211	3,818	3,420	3,891	11,881	11,193	7,439	5,557	3,089	2,883	62,875
DISCONTINUED/COMPLETED																								
Commercial Showerhead	0	67	93	36	4	124	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	322
Infrared Heat Lamp	0	18	159	34	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	216
Livestock Waterer	0	0	0	0	0	137	118	84	24	4	0	0	0	0	0	0	0	0	0	0	0	0	0	367
Roadway Lighting	0	116	1,531	2,159	1,972	1,498	18	0	48	0	0	0	0	0	0	0	0	0	0	0	0	0	0	7,342
Sentinel Lighting	0	33	1,350	1,131	1,160	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,673
Commercial Air Barrier	0	0	0	0	8	29	46	81	78	1	1	17	11	10	9	5	1	0	1	0	0	0	0	298
Agricultural Demand Controller	0	0	33	464	158	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	655
Commercial Air Conditioning	0	0	0	0	1	2	3	81	78	0	0	0	3	20	0	12	2	0	0	0	0	0	0	201
Aboriginal Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Parking Lot Controllers	0	0	0	0	40	136	219	81	78	70	5	33	160	91	223	294	514	186	122	150	152	82	287	2,924
Spray Valves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	14	16	5	6	1	0	42
Agricultural Heat Pads	0	0	0	0	0	0	3	70	36	42	30	21	24	33	28	83	45	44	29	19	33	28	8	577
Subtotal	0	233	3,165	3,824	3,348	1,925	407	397	341	117	37	72	198	154	261	394	563	244	168	175	191	111	295	16,619
	0	233	3,397	4,933	4,576	3,064	1,358	1,081	1,148	744	507	653	861	1,365	4,078	3,814	4,454	12,125	11,361	7,613	5,748	3,201	3,178	79,494
INDUSTRIAL																								
Performance Optimization Program	0	0	90	192	246	356	262	307	276	212	227	214	300	2,015	416	199	351	414	523	612	464	414	417	8,505
Emergency Preparedness Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	86	73	338	1	498
Subtotal	0	0	90	192	246	356	262	307	276	212	227	214	300	2,015	416	199	351	414	523	698	537	752	418	9,003
DISCONTINUED/COMPLETED																								
Industrial (Basic)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofit/Demonstration GSL	0	0	65	290	295	217	405	366	337	48	11	5	0	0	0	0	0	39	0	0	0	0	0	2,077
High Efficiency Motors	0	23	281	354	274	241	257	279	353	48	3	0	0	0	0	0	0	0	0	0	0	0	0	2,113
Efficient Motors (QMR)	0	0	0	23	54	20	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	101
Subtotal	0	23	345	667	623	478	666	645	689	95	15	5	0	0	0	0	0	39	0	0	0	0	0	4,291
	0	23	435	859	869	834	928	952	966	307	242	218	300	2,015	416	199	351	453	523	698	537	752	418	13,294
EFFICIENCY PROGRAMS SUBTOTAL	153	549	4,250	6,131	5,928	4,450	2,798	2,866	3,036	1,228	764	984	1,454	3,862	5,052	5,644	7,825	15,230	15,136	11,972	9,300	5,228	5,795	119,634
CUSTOMER SELF-GENERATION PROGRAMS																								
BioEnergy Optimization Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	78	301	319	1,756	2,453
RATE/LOAD MANAGEMENT PROGRAMS																								
Curtailable Rate Program	0	0	0	88	125	222	76	52	49	35	36	35	10	10	14	18	10	8	10	5	7	7	9	827
Support Costs	0	365	3,507	4,214	2,994	1,666	1,979	1,589	1,265	1,641	2,336	3,099	2,702	3,495	3,490	3,409	2,498	2,072	2,007	3,684	3,710	3,223	2,851	57,794
GRAND TOTAL	153	914	7,756	10,433	9,047	6,338	4,853	4,507	4,351	2,904	3,135	4,118	4,166	7,366	8,557	9,070	10,333	17,310	17,153	15,739	13,318	8,777	10,411	180,707

Note: May not add up due to rounding.

PUB/MH I-59b
Attachment 2
Page 127 of 149

2012/13 PS Plan
Annual Program Incentive Costs
(1989/90 - 2011/12)
(000's in 2012 $)

	1989/90	1990/91	1991/92	1992/93	1993/94	1994/95	1995/96	1996/97	1997/98	1998/99	1999/00	2000/01	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	Interim Estimate 2011/12	Cumulative 2011/12
RESIDENTIAL																								
Home Insulation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	499	719	1,688	1,380	1,549	1,563	1,198	1,035	9,631
Lower Income Energy Efficiency Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	42	315	789	113	64	1,324
New Home Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	11	69	133	118	107	118	86	45	688
Refrigerator Retirement Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	325	325
Water and Energy Saver Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	283	188	471
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	511	788	1,821	1,540	1,971	2,471	1,681	1,656	12,439
Customer Service Initiatives																								
Power Smart Residential Loan Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Earth Power Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ecoEnergy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Solar H2O Heater	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
DISCONTINUED/COMPLETED																								
Appliances	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,022	1,408	1,391	304	0	0	4,126
Seasonal LED Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	32	165	118	71	22	0	0	408
Outdoor Timer	50	70	61	36	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	247
Res Hot Water	0	0	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9
Water Heater Rental	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Thermostat	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	23	11	6	0	0	0	39
Retrofit/Demonstration	0	0	0	0	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4
RBB	0	0	26	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	26
High Efficiency Furnace & Boiler	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Efficient Light Fixtures	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	34	109	73	66	154	140	576
Aboriginal Programs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Compact Fluorescent Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	164	275	242	264	685	1,122	621	-10	3,363
Subtotal	50	70	96	36	30	0	4	0	0	0	0	0	0	0	0	164	307	1,485	1,910	2,226	1,514	776	130	8,800
Exploratory Programs																								
Exploratory Programs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
RESIDENTIAL TOTAL	50	70	96	36	30	0	4	0	0	0	0	0	0	0	0	674	1,095	3,307	3,450	4,197	3,985	2,457	1,786	21,239
COMMERCIAL																								
Commercial Lighting Program	0	0	0	313	1,573	2,199	2,298	779	463	1,631	602	333	628	392	1,642	3,555	4,742	5,367	5,730	6,238	5,634	4,980	4,584	53,683
Commercial Earth Power Program	0	0	0	0	0	0	0	31	152	91	124	73	91	146	366	132	323	450	149	97	276	208	173	2,880
Commercial Insulation Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	77	120	206	194	244	206	1,047
Commercial Windows Program	0	0	0	0	0	0	0	50	96	55	43	53	56	117	91	187	277	251	233	361	939	1,144	887	4,840
Internal Retrofit Program	0	0	0	53	268	390	102	147	107	171	70	207	90	184	514	545	423	0	0	0	0	0	606	3,878
Commercial Custom Measures Program	0	0	0	0	0	0	0	31	0	131	452	54	53	22	97	3	7	43	162	35	130	147	101	1,467
Commercial Refrigeration Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	97	107	86	91	90	205	675
Commercial HVAC Program - Chiller	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	110	190	61	210	151	309	195	1,227
City of Winnipeg Power Smart Agreement	0	0	0	0	0	0	0	0	0	0	0	0	0	0	813	971	3,831	1,463	154	0	0	164	73	7,469
Commercial Clothes Washers Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	9	103	24	28	165
Commercial Kitchen Appliance Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	47	50	24	14	134
Power Smart Shops	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	3	0	6
Commercial Building Optimization Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	8	9	10	13	40
Network Energy Management Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	12	0	17
New Buildings Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	114	113	227
CO2 Sensors	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1
Power Smart Energy Manager Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0	0	0	3
Subtotal	0	0	0	365	1,841	2,589	2,400	1,038	818	2,080	1,292	719	918	861	3,523	5,394	9,714	7,938	6,716	7,299	7,584	7,474	7,198	77,760
DISCONTINUED/COMPLETED																								
Commercial Showerhead	0	0	30	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	30
Infrared Heat Lamp	0	0	135	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	135
Livestock Waterer	0	0	0	0	0	21	18	11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	50
Roadway Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sentinel Lighting	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Air Barrier	0	0	0	0	0	0	0	19	2	3	10	17	11	8	10	3	3	0	5	0	0	0	0	90
Agricultural Demand Controller	0	0	0	181	61	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	242
Commercial Air Conditioning	0	0	0	0	0	0	0	1	0	0	0	0	4	35	0	130	9	0	0	0	0	0	0	179
Aboriginal Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Parking Lot Controllers	0	0	0	0	0	0	0	35	27	126	16	21	50	24	74	81	599	775	495	249	382	468	0	3,421
Spray Valves	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	26	13	18	3	5	0	65
Agricultural Heat Pads	0	0	0	0	0	0	0	0	0	51	62	28	38	37	35	51	31	25	34	26	87	75	0	580
Subtotal	0	0	166	181	61	21	18	67	29	179	88	65	103	104	118	264	641	826	547	293	473	548	0	4,792
	0	0	166	546	1,903	2,609	2,418	1,105	847	2,259	1,380	784	1,022	965	3,641	5,658	10,355	8,764	7,263	7,592	8,057	8,022	7,198	82,553
INDUSTRIAL																								
Performance Optimization Program	0	0	0	0	0	150	251	155	396	196	44	205	758	1,324	839	1,503	1,422	724	2,879	2,037	2,594	2,466	2,574	20,516
Emergency Preparedness Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	150	251	155	396	196	44	205	758	1,324	839	1,503	1,422	724	2,879	2,037	2,594	2,466	2,574	20,516
DISCONTINUED/COMPLETED																								
Industrial (Basic)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofit/Demonstration GSL	0	0	0	38	56	413	677	0	0	39	0	0	0	0	0	0	0	0	0	0	0	0	0	1,222
High Efficiency Motors	0	0	38	419	345	251	194	210	305	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,762
Efficient Motors (QMR)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	38	457	400	664	871	210	305	39	0	0	0	0	0	0	0	0	0	0	0	0	0	2,985
	0	0	38	457	400	815	1,122	365	702	235	44	205	758	1,324	839	1,503	1,422	724	2,879	2,037	2,594	2,466	2,574	23,501
EFFICIENCY PROGRAMS SUBTOTAL	50	70	300	1,039	2,333	3,424	3,544	1,470	1,549	2,494	1,424	989	1,779	2,289	4,479	7,835	12,873	12,794	13,593	13,826	14,636	12,945	11,558	127,292
CUSTOMER SELF-GENERATION PROGRAMS																								
BioEnergy Optimization Program	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	155	1,781	1,604	1,741	1,262	1,351	0	7,894
RATE/LOAD MANAGEMENT PROGRAMS																								
Curtailable Rate Program	0	0	0	0	526	1,378	1,363	1,359	1,172	1,525	1,894	2,439	3,250	4,906	6,423	6,437	7,186	7,032	6,969	6,748	6,054	5,966	5,895	78,522
Support Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
GRAND TOTAL	50	70	300	1,039	2,859	4,802	4,907	2,829	2,721	4,019	3,317	3,428	5,029	7,195	10,903	14,272	20,214	21,607	22,166	22,315	21,952	20,261	17,452	213,708

Note: May not add up due to rounding.

APPENDIX C – 2012/13 POWER SMART PLAN NATURAL GAS

APPENDIX C.1 - ANNUAL ENERGY SAVINGS (MILLION M3)

APPENDIX C.2 - ANNUAL UTILITY COSTS

APPENDIX C.3 - ANNUAL PROGRAM ADMINISTRATION COSTS

APPENDIX C.4 - ANNUAL PROGRAM INCENTIVE COSTS

2012/13 PS Plan
Annual Energy Savings
(million m3)

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	
RESIDENTIAL																
Incentive Based																
Home Insulation Program	0.7	1.7	2.7	3.6	4.6	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.8	
Water and Energy Saver Program	0.5	1.3	2.1	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	
Lower Income Energy Efficiency Program	0.8	1.9	3.1	4.3	5.4	5.6	5.1	4.6	4.2	3.8	3.5	3.4	3.3	3.1	3.0	
Subtotal	2.0	5.0	7.9	10.3	12.4	12.8	12.3	11.9	11.4	11.0	10.8	10.6	10.5	10.3	10.2	18%
Customer Service Initiatives / Financial Loan Programs																
Power Smart Residential Loan	0.2	0.6	0.9	1.3	1.6	1.9	2.3	2.6	2.9	3.3	3.6	4.0	4.3	4.6	5.0	
Residential Earth Power Loan	0.1	0.2	0.3	0.4	0.5	0.7	0.8	0.9	1.1	1.2	1.4	1.6	1.8	1.8	1.8	
Power Smart PAYS Financing	0.0	0.1	0.3	0.5	0.7	1.0	1.2	1.5	1.8	2.0	2.3	2.5	2.8	3.1	3.3	
Subtotal	0.4	0.9	1.5	2.1	2.8	3.6	4.3	5.0	5.8	6.5	7.3	8.1	8.9	9.5	10.1	18%
COMMERCIAL																
Commercial Custom Measures Program	0.1	0.2	0.3	0.4	0.5	0.6	0.8	0.9	1.0	1.2	1.3	1.5	1.7	1.8	2.0	
Commercial Windows Program	0.3	0.6	0.9	1.1	1.2	1.4	1.5	1.6	1.7	1.8	2.0	2.1	2.2	2.3	2.4	
Commercial Insulation Program	0.9	1.9	2.7	3.4	3.9	4.4	4.8	5.2	5.6	5.7	5.9	6.0	6.1	6.1	6.2	
New Buildings Program	0.3	1.1	1.9	2.9	3.8	4.8	5.9	6.2	6.2	6.2	6.2	6.2	6.2	6.2	6.2	
Commercial Building Optimization Program	0.2	0.5	0.8	1.1	1.5	1.9	2.2	2.6	3.1	3.6	3.9	4.2	4.5	4.9	5.2	
Internal Retrofit Program	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	
Commercial Kitchen Appliance Program	0.0	0.1	0.4	0.6	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.8	0.5	0.3	0.2	
Commercial Clothes Washers Program	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	
CO2 Sensors	0.1	0.2	0.3	0.4	0.6	0.8	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.2	1.2	
Commercial Boiler Program	0.7	1.1	1.4	1.6	1.8	2.0	2.3	2.5	2.8	3.0	3.2	3.4	3.6	3.6	3.6	
Subtotal	2.6	5.7	8.7	11.5	14.2	16.8	19.4	21.1	22.4	23.6	24.5	25.4	26.0	26.6	27.0	47%
Customer Service Initiatives / Financial Loan Programs																
Power Smart for Business PAYS Financing	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
Subtotal	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0%
Market Effects																
Commercial Rinse & Save Program	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	
Subtotal	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%
INDUSTRIAL																
Industrial Natural Gas Optimization Program	0.9	2.5	3.8	5.0	6.2	7.4	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	
Subtotal	0.9	2.5	3.8	5.0	6.2	7.4	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	14%
CONSERVATION SUBTOTAL	5.8	14.0	22.1	29.1	35.7	40.7	44.1	46.1	47.8	49.2	50.7	52.2	53.5	54.5	55.4	97%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																
BioEnergy Optimization Program	0.0	0.4	0.6	1.1	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	0.0	0.4	0.6	1.1	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	1.5	3%
Program Impacts	6	14	23	30	37	42	46	48	49	51	52	54	55	56	57	100%
Interactive Effects	-0.6	-1.8	-2.3	-2.4	-2.5	-2.5	-2.6	-2.6	-2.6	-2.7	-2.7	-2.1	-1.1	-0.8	-0.8	
Subtotal	5	13	20	28	35	40	43	45	47	48	50	52	54	55	56	
Codes, Standards & Regulations	1.9	4.6	7.3	9.9	12.6	13.6	13.9	14.3	14.6	14.8	15.1	15.3	15.5	15.7	15.9	
POWER SMART 2012 to 2026 Impacts	7	17	28	38	47	53	57	59	61	63	65	67	69	71	72	
POWER SMART SAVINGS TO DATE																
Incentive Based Program Impacts	43.9	43.9	43.7	43.0	43.0	43.0	42.9	42.7	42.5	42.3	42.0	39.8	38.8	37.5	33.8	
Customer Service Initiatives Program Impacts	19.1	19.1	19.1	19.1	19.1	19.1	19.1	19.1	19.1	19.1	19.1	19.0	18.6	18.3	18.1	
Discontinued Programs	9.8	9.7	9.5	9.5	8.7	8.4	7.4	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	
Interactive Effects	-9.0	-7.1	-4.0	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.3	-2.4	-2.5	-2.0	-1.2	-1.3	
Impacts of Codes & Standards	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	5.8	
TOTAL m3	77	89	102	113	122	127	130	132	134	135	136	136	138	139	136	

Note: May not add up due to rounding.

2012/13 PS Plan
Annual Utility Costs
(000's in 2012 $)

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	Cumulative Total	
RESIDENTIAL																	
Incentive Based																	
Home Insulation Program	$1,697	$1,688	$1,685	$1,719	$1,738	$329	$246	$246	$246	$246	$246	$246	$246	$246	$246	$11,066	
Water and Energy Saver Program	$804	$804	$804	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,411	
Lower Income Energy Efficiency Program	$760	$744	$730	$647	$636	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,517	
Subtotal	$3,261	$3,236	$3,218	$2,366	$2,374	$329	$246	$246	$246	$246	$246	$246	$246	$246	$246	$16,994	33%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Residential Earth Power Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Power Smart PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
COMMERCIAL																	
Commercial Custom Measures Program	$141	$141	$141	$141	$141	$151	$151	$151	$151	$150	$160	$160	$160	$160	$159	$2,258	
Commercial Windows Program	$438	$422	$380	$196	$185	$176	$170	$164	$160	$156	$153	$151	$149	$148	$147	$3,195	
Commercial Insulation Program	$1,613	$1,435	$1,291	$951	$856	$781	$647	$599	$560	$309	$284	$264	$175	$163	$152	$10,079	
New Buildings Program	$569	$440	$529	$648	$711	$775	$841	$0	$0	$0	$0	$0	$0	$0	$0	$4,513	
Commercial Building Optimization Program	$255	$276	$276	$276	$339	$339	$339	$339	$380	$380	$422	$484	$505	$505	$505	$5,621	
Internal Retrofit Program	$53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$53	
Commercial Kitchen Appliance Program	$38	$88	$102	$105	$53	$65	$0	$0	$0	$0	$0	$0	$0	$0	$0	$452	
Commercial Clothes Washers Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
CO2 Sensors	$58	$59	$61	$62	$64	$66	$68	$4	$4	$4	$4	$4	$4	$4	$4	$470	
Commercial Boiler Program	$1,025	$543	$516	$7	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$0	$2,155	
Subtotal	$4,191	$3,403	$3,296	$2,386	$2,355	$2,359	$2,222	$1,263	$1,262	$1,007	$1,030	$1,070	$999	$985	$968	$28,796	57%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
Market Effects																	
Commercial Rinse & Save Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
INDUSTRIAL																	
Industrial Natural Gas Optimization Program	$770	$770	$640	$640	$640	$640	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,102	
Subtotal	$770	$770	$640	$640	$640	$640	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4,102	8%
CONSERVATION SUBTOTAL	$8,223	$7,410	$7,155	$5,392	$5,369	$3,329	$2,468	$1,509	$1,507	$1,252	$1,275	$1,316	$1,245	$1,231	$1,213	$49,893	98%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
BioEnergy Optimization Program	$139	$221	$43	$279	$43	$46	$43	$43	$0	$0	$0	$0	$0	$0	$0	$857	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	$139	$221	$43	$279	$43	$46	$43	$43	$0	$0	$0	$0	$0	$0	$0	$857	2%
Subtotal of Programs	$8,362	$7,631	$7,198	$5,671	$5,412	$3,375	$2,511	$1,552	$1,507	$1,252	$1,275	$1,316	$1,245	$1,231	$1,213	$50,750	100%
Program Support	$1,632	$1,596	$1,596	$1,596	$1,596	$1,596	$1,596	$1,596	$1,596	$1,593	$1,593	$1,593	$1,591	$1,591	$1,591	$23,951	
Contingency	$0	$265	$325	$600	$600	$550	$500	$500	$500	$500	$500	$1,000	$1,000	$1,000	$1,000	$8,840	
Total Utility Costs (2012 to 2026)	$9,994	$9,491	$9,118	$7,867	$7,608	$5,521	$4,606	$3,647	$3,603	$3,345	$3,368	$3,909	$3,836	$3,822	$3,805	$83,541	
Total Committed to Date																$72,604	
TOTAL UTILITY COSTS (1989 to 2026)	$9,994	$9,491	$9,118	$7,867	$7,608	$5,521	$4,606	$3,647	$3,603	$3,345	$3,368	$3,909	$3,836	$3,822	$3,805	$156,145	

Note: May not add up due to rounding.

2012/13 PS Plan
Annual Program Administration Costs
(000's in 2012 $)

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	Cumulative Total	
RESIDENTIAL																	
Incentive Based																	
Home Insulation Program	$214	$187	$190	$194	$198	$84	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,068	
Water and Energy Saver Program	$479	$479	$479	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,437	
Lower Income Energy Efficiency Program	$236	$236	$236	$166	$166	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,040	
Subtotal	$929	$902	$905	$360	$365	$84	$0	$0	$0	$0	$0	$0	$0	$0	$0	$3,545	27%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Residential Earth Power Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Power Smart PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
COMMERCIAL																	
Commercial Custom Measures Program	$110	$110	$110	$110	$110	$110	$110	$110	$110	$110	$110	$110	$110	$110	$110	$1,648	
Commercial Windows Program	$67	$67	$67	$67	$67	$67	$67	$67	$67	$67	$67	$67	$67	$67	$67	$1,006	
Commercial Insulation Program	$86	$86	$86	$86	$86	$86	$86	$86	$86	$86	$86	$86	$86	$86	$86	$1,292	
New Buildings Program	$158	$158	$158	$158	$158	$158	$158	$0	$0	$0	$0	$0	$0	$0	$0	$1,106	
Commercial Building Optimization Program	$89	$89	$89	$89	$89	$89	$89	$89	$89	$89	$89	$89	$89	$89	$89	$1,329	
Internal Retrofit Program	$53	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$53	
Commercial Kitchen Appliance Program	$32	$33	$32	$31	$19	$19	$0	$0	$0	$0	$0	$0	$0	$0	$0	$166	
Commercial Clothes Washers Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
CO2 Sensors	$40	$38	$35	$33	$30	$27	$25	$4	$4	$4	$4	$4	$4	$4	$4	$260	
Commercial Boiler Program	$262	$188	$160	$7	$7	$7	$7	$7	$7	$7	$6	$6	$6	$6	$0	$682	
Subtotal	$897	$769	$737	$581	$565	$563	$541	$362	$362	$362	$361	$361	$361	$361	$356	$7,541	58%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
Market Effects																	
Commercial Rinse & Save Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
INDUSTRIAL																	
Industrial Natural Gas Optimization Program	$250	$250	$250	$250	$250	$250	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,502	
Subtotal	$250	$250	$250	$250	$250	$250	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,502	12%
CONSERVATION SUBTOTAL	$2,076	$1,922	$1,892	$1,192	$1,180	$897	$541	$362	$362	$362	$361	$361	$361	$361	$356	$12,589	97%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
BioEnergy Optimization Program	$133	$37	$37	$37	$37	$37	$37	$37	$0	$0	$0	$0	$0	$0	$0	$393	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	$133	$37	$37	$37	$37	$37	$37	$37	$0	$0	$0	$0	$0	$0	$0	$393	3%
Subtotal of Programs	$2,210	$1,959	$1,929	$1,229	$1,217	$934	$578	$399	$362	$362	$361	$361	$361	$361	$356	$12,981	100%
Program Support	$1,632	$1,596	$1,596	$1,596	$1,596	$1,596	$1,596	$1,596	$1,596	$1,593	$1,593	$1,593	$1,591	$1,591	$1,591	$23,951	
Contingency	$0	$265	$325	$600	$600	$550	$500	$500	$500	$500	$500	$1,000	$1,000	$1,000	$1,000	$8,840	
Total Administration Costs (2012 to 2026)	$3,842	$3,819	$3,850	$3,424	$3,413	$3,080	$2,674	$2,495	$2,458	$2,456	$2,455	$2,955	$2,953	$2,953	$2,947	$45,772	
Total Committed to Date																$31,821	
TOTAL ADMINISTRATION COSTS (1989 to 2026)	$3,842	$3,819	$3,850	$3,424	$3,413	$3,080	$2,674	$2,495	$2,458	$2,456	$2,455	$2,955	$2,953	$2,953	$2,947	$77,594	

Note: May not add up due to rounding.

2012/13 PS Plan
Annual Program Incentive Costs
(000's in 2012 $)

	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	Cumulative Total	
RESIDENTIAL																	
Incentive Based																	
Home Insulation Program	$1,483	$1,501	$1,495	$1,524	$1,540	$246	$246	$246	$246	$246	$246	$246	$246	$246	$246	$9,998	
Water and Energy Saver Program	$325	$325	$325	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$974	
Lower Income Energy Efficiency Program	$524	$508	$494	$481	$469	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,476	
Subtotal	$2,331	$2,334	$2,314	$2,005	$2,009	$246	$246	$246	$246	$246	$246	$246	$246	$246	$246	$13,449	36%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart Residential Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Residential Earth Power Loan	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Power Smart PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0		
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
COMMERCIAL																	
Commercial Custom Measures Program	$31	$31	$31	$31	$31	$41	$41	$41	$41	$41	$50	$50	$50	$50	$49	$610	
Commercial Windows Program	$371	$355	$313	$129	$118	$109	$102	$97	$93	$89	$86	$84	$82	$81	$80	$2,190	
Commercial Insulation Program	$1,527	$1,348	$1,205	$865	$770	$694	$561	$513	$474	$223	$198	$178	$89	$76	$66	$8,788	
New Buildings Program	$411	$282	$371	$490	$553	$617	$683	$0	$0	$0	$0	$0	$0	$0	$0	$3,407	
Commercial Building Optimization Program	$167	$188	$188	$188	$250	$250	$250	$250	$292	$292	$333	$396	$417	$417	$417	$4,293	
Internal Retrofit Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Commercial Kitchen Appliance Program	$7	$55	$70	$74	$34	$46	$0	$0	$0	$0	$0	$0	$0	$0	$0	$286	
Commercial Clothes Washers Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
CO2 Sensors	$18	$21	$25	$29	$34	$38	$44	$0	$0	$0	$0	$0	$0	$0	$0	$209	
Commercial Boiler Program	$762	$354	$357	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,473	
Subtotal	$3,295	$2,634	$2,559	$1,805	$1,789	$1,797	$1,681	$901	$899	$644	$668	$709	$638	$624	$612	$21,255	56%
Customer Service Initiatives / Financial Loan Programs																	
Power Smart for Business PAYS Financing	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
Market Effects																	
Commercial Rinse & Save Program	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	0%
INDUSTRIAL																	
Industrial Natural Gas Optimization Program	$520	$520	$390	$390	$390	$390	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,600	
Subtotal	$520	$520	$390	$390	$390	$390	$0	$0	$0	$0	$0	$0	$0	$0	$0	$2,600	7%
CONSERVATION SUBTOTAL	$6,146	$5,488	$5,262	$4,200	$4,189	$2,432	$1,927	$1,146	$1,145	$890	$914	$954	$884	$869	$858	$37,304	99%
LOAD DISPLACEMENT & ALTERNATIVE ENERGY																	
BioEnergy Optimization Program	$6	$184	$6	$242	$6	$9	$6	$6	$0	$0	$0	$0	$0	$0	$0	$465	
LOAD DISPLACEMENT & ALTERNATIVE ENERGY SUBTOTAL	$6	$184	$6	$242	$6	$9	$6	$6	$0	$0	$0	$0	$0	$0	$0	$465	1%
Total Incentive Costs (2012 to 2026)	$6,152	$5,672	$5,268	$4,443	$4,195	$2,441	$1,933	$1,152	$1,145	$890	$914	$954	$884	$869	$858	$37,769	100%
Total Committed to Date																$40,643	
TOTAL INCENTIVE COSTS (1989 to 2026)	$6,152	$5,672	$5,268	$4,443	$4,195	$2,441	$1,933	$1,152	$1,145	$890	$914	$954	$884	$869	$858	$78,412	

Note: May not add up due to rounding.

APPENDIX D – HISTORICAL NATURAL GAS SAVINGS & COSTS

APPENDIX D.1 - ANNUAL ENERGY SAVINGS (MILLION M3)

APPENDIX D.2 - ANNUAL UTILITY COSTS

APPENDIX D.3 - ANNUAL PROGRAM ADMINISTRATION COSTS

APPENDIX D.4 - ANNUAL PROGRAM INCENTIVE COSTS

2012/13 PS Plan
Annual Energy Savings
(Savings to Date)
(million m3)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	Interim Estimate 2011/12	Benchmark 2026/27
RESIDENTIAL												
Home Insulation Program	0.00	0.00	0.00	0.00	0.30	2.15	3.85	5.58	7.59	9.01	10.17	10.17
Lower Income Energy Efficiency Program	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.06	0.69	2.32	3.53	2.44
New Home Program	0.00	0.00	0.00	0.03	0.08	0.15	0.23	0.34	0.41	0.52	0.56	0.56
Water and Energy Saver Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.83	1.94	0.00
Subtotal	0.00	0.00	0.00	0.03	0.39	2.30	4.10	5.98	8.69	12.68	16.20	13.18
CUSTOMER SERVICE INITIATIVES												
Power Smart Residential Loan Program	1.23	2.14	3.51	5.57	7.80	9.56	11.30	12.29	13.93	14.27	14.65	14.65
Residential Earth Power Program	0.00	0.05	0.15	0.50	0.79	0.97	1.31	1.45	1.67	2.10	2.14	1.17
ecoEnergy	0.00	0.13	0.39	1.25	2.32	2.32	2.32	2.32	2.32	2.32	2.32	2.32
Solar H2O Heater	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Subtotal	1.23	2.31	4.04	7.32	10.91	12.85	14.94	16.05	17.93	18.69	19.12	18.15
DISCONTINUED/COMPLETED												
Thermostat	0.00	0.00	0.00	0.00	0.00	0.11	0.17	0.17	0.17	0.17	0.17	0.17
High Efficiency Furnace & Boiler	0.00	0.00	0.00	0.00	0.61	2.60	4.04	5.77	6.93	6.96	6.96	6.96
Power Smart Energy Manager	-0.01	0.05	0.18	0.32	0.32	0.32	0.32	0.32	0.32	0.32	0.33	0.00
R2000 House	0.01	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Subtotal	0.00	0.07	0.21	0.35	0.95	3.06	4.56	6.29	7.44	7.48	7.49	7.16
RESIDENTIAL TOTAL	1.23	2.38	4.25	7.70	12.25	18.21	23.59	28.32	34.06	38.85	42.81	38.48
COMMERCIAL												
Commercial Insulation Program	0.00	0.00	0.00	0.00	0.00	0.29	1.05	2.15	3.24	5.37	6.88	6.88
Commercial Windows Program	0.00	0.00	0.00	0.00	0.00	0.03	0.11	0.23	0.50	0.83	1.24	1.24
Commercial Custom Measures Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.09	0.17	0.26	0.26
City of Winnipeg Power Smart Agreement	0.00	0.05	0.13	0.17	0.56	0.67	0.67	0.67	0.71	0.78	0.82	0.23
Commercial Clothes Washers Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.02	0.00
Commercial Kitchen Appliance Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.03	0.05	0.07	0.02
Power Smart Shops	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.04	0.04	0.00
Commercial Building Optimization Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.13	0.24	0.36	0.36	0.00
Network Energy Management Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
New Buildings Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.31	0.31
HVAC - CO2 Sensors	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.22	0.00
HVAC - Boilers	0.00	0.00	0.00	0.00	0.00	0.42	2.52	4.81	6.20	6.20	7.00	6.95
Subtotal	0.00	0.05	0.13	0.17	0.56	1.41	4.36	8.00	11.02	13.82	17.22	15.90
DISCONTINUED/COMPLETED												
Spray Valves	0.00	0.00	0.00	0.00	0.00	0.83	1.12	2.11	2.37	2.37	2.37	0.00
Subtotal	0.00	0.00	0.00	0.00	0.00	0.83	1.12	2.11	2.37	2.37	2.37	0.00
COMMERCIAL SUBTOTAL	0.00	0.05	0.13	0.17	0.56	2.24	5.48	10.11	13.39	16.19	19.59	15.90
INDUSTRIAL												
Industrial Natural Gas Optimization	0.00	0.00	0.00	0.00	0.00	0.00	1.69	3.85	4.94	8.04	10.53	4.76
Subtotal	0.00	0.00	0.00	0.00	0.00	0.00	1.69	3.85	4.94	8.04	10.53	4.76
EFFICIENCY PROGRAMS SUBTOTAL	1.23	2.44	4.38	7.88	12.81	20.45	30.76	42.28	52.40	63.08	72.93	59.14
CUSTOMER SELF-GENERATION PROGRAMS												
BioEnergy Optimization Program	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
RATE/LOAD MANAGEMENT PROGRAMS												
Interactive Effects	0.00	0.00	0.00	-1.20	-2.57	-3.00	-3.79	-5.86	-8.53	-9.97	-9.73	-1.33
Subtotal after Interactive Effects	1.23	2.43	4.38	6.67	10.24	17.46	26.97	36.42	43.86	53.11	63.19	57.81
Codes, Standards & regulations	0.35	0.71	1.12	1.55	1.97	2.37	2.73	2.97	3.52	4.41	5.76	5.76
Power Smart 2012 to 2026 Impacts	1.58	3.14	5.50	8.23	12.21	19.83	29.70	39.39	47.38	57.52	68.96	63.57

Note: May not add up due to rounding.

2012/13 PS Plan
Annual Utility Costs
(2001/02 - 2011/12)
(000's in 2012 $)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	Interim Estimate 2011/12	Cumulative Total 2011/12
RESIDENTIAL												
Home Insulation Program	0	0	0	0	403	1,968	3,153	2,911	3,095	2,320	2,146	15,997
Lower Income Energy Efficiency Program	0	0	0	0	0	58	162	217	775	823	839	2,873
New Home Program	0	13	80	98	66	100	147	0	91	113	65	773
Water and Energy Saver Program	0	0	0	0	0	0	0	0	42	713	1,045	1,801
Subtotal	0	13	80	98	469	2,126	3,462	3,127	4,003	3,970	4,095	21,443
CUSTOMER SERVICE INITIATIVES												
Power Smart Residential Loan Program	453	117	53	-6	16	188	-23	-113	-689	-730	-556	-1,290
Residential Earth Power Program	0	0	0	0	0	0	0	0	0	0	0	0
ecoEnergy	261	301	304	364	-10	670	514	-114	594	397	479	3,759
Solar H2O Heater	0	0	0	0	0	0	0	0	2	0	0	2
Subtotal	714	419	356	358	5	858	491	-227	-93	-333	-77	2,471
DISCONTINUED/COMPLETED												
Thermostat	0	0	0	0	0	206	139	40	1	0	0	386
High Efficiency Furnace & Boiler	0	0	0	0	623	1,410	2,246	3,350	1,609	32	0	9,271
Subtotal	0	0	0	0	623	1,617	2,385	3,390	1,610	32	0	9,657
RESIDENTIAL TOTAL	714	432	436	457	1,098	4,600	6,337	6,290	5,521	3,669	4,017	33,571
COMMERCIAL												
Commercial Insulation Program	0	0	0	0	0	448	874	1,069	1,305	2,294	1,787	7,777
Commercial Windows Program	0	0	0	0	0	137	297	489	819	1,037	1,115	3,894
Commercial Custom Measures Program	0	0	0	0	81	245	167	167	246	213	161	1,280
Commercial Water Heater Program	0	0	0	0	0	0	0	0	23	32	14	70
City of Winnipeg Power Smart Agreement	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Clothes Washers Program	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Kitchen Appliance Program	0	0	0	0	0	0	0	17	58	30	48	153
Power Smart Shops	0	0	0	0	0	0	1	16	85	99	12	212
Commercial Building Optimization Program	0	0	0	0	0	0	0	0	147	160	120	427
New Buildings Program	0	0	0	0	0	0	0	151	113	201	202	668
Commercial Boiler Program	0	0	0	0	112	647	1,754	1,459	1,177	1,276	898	7,323
HVAC - CO2 Sensors	0	0	0	0	0	0	0	0	0	0	35	35
Power Smart Energy Manager Program	0	0	0	0	0	0	126	100	74	0	52	352
Subtotal	0	0	0	0	193	1,477	3,219	3,467	4,047	5,342	4,446	22,191
DISCONTINUED/COMPLETED												
Spray Valves	0	0	0	0	0	137	58	129	28	22	1	375
Subtotal	0	0	0	0	0	137	58	129	28	22	1	375
COMMERCIAL TOTAL	0	0	0	0	193	1,614	3,277	3,596	4,075	5,364	4,447	22,567
INDUSTRIAL												
Industrial Natural Gas Optimization Program	0	0	0	0	109	39	307	353	628	729	721	2,885
Subtotal	0	0	0	0	109	39	307	353	628	729	721	2,885
EFFICIENCY PROGRAMS SUBTOTAL	714	432	436	457	1,400	6,253	9,921	10,239	10,223	9,761	9,186	59,023
CUSTOMER SELF-GENERATION PROGRAMS												
BioEnergy Optimization Program	0	0	0	0	0	0	14	8	0	0	0	22
Support Costs	212	234	253	557	1,379	1,790	1,626	2,268	2,171	1,750	1,320	13,558
GRAND TOTAL	925	666	689	1,014	2,779	8,043	11,561	12,515	12,395	11,511	10,505	72,604

Note: May not add up due to rounding.

2012/13 PS Plan
Annual Program Admininstration Costs
(2001/02 - 2011/12)
(000's in 2012 $)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	Interim Estimate 2011/12	Cumulative Total 2011/12
RESIDENTIAL												
Home Insulation Program	0	0	0	0	183	563	808	631	495	518	529	3,728
Lower Income Energy Efficiency Program	0	0	0	0	84	0	150	137	193	485	839	1,887
New Home Program	0	0	0	0	0	0	0	0	42	131	17	191
Water and Energy Saver Program	0	13	80	81	22	33	52	0	16	0	607	904
Subtotal	0	13	80	81	289	596	1,010	767	746	1,135	1,991	6,710
CUSTOMER SERVICE INITIATIVES												
Power Smart Residential Loan Program	453	117	53	-6	16	188	-23	-113	-689	-730	-556	-1,290
Residential Earth Power Program	0	0	0	0	0	0	0	0	0	0	0	0
ecoEnergy	261	301	304	364	-10	670	514	-114	594	397	479	3,759
Solar H2O Heater	0	0	0	0	0	0	0	0	2	0	0	2
Subtotal	714	419	356	358	5	858	491	-227	-93	-333	-77	2,471
DISCONTINUED/COMPLETED												
Thermostat	0	0	0	0	281	309	476	376	205	17	0	1,664
High Efficiency Furnace & Boiler	0	0	0	0	0	118	100	19	1	0	0	237
Subtotal	0	0	0	0	281	426	576	395	206	17	0	1,902
RESIDENTIAL TOTAL	714	432	436	439	576	1,880	2,077	935	859	820	1,914	11,083
COMMERCIAL												
Commercial Insulation Program	0	0	0	0	112	302	314	265	364	271	275	1,905
Commercial Windows Program	0	0	0	0	81	245	167	122	162	159	177	1,114
Commercial Custom Measures Program	0	0	0	0	0	87	91	129	148	175	94	723
Commercial Water Heater Program	0	0	0	0	0	0	0	0	23	32	14	70
City of Winnipeg Power Smart Agreement	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Clothes Washers Program	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Kitchen Appliance Program	0	0	0	0	0	0	0	9	24	11	28	72
Power Smart Shops	0	0	0	0	0	0	126	98	74	0	12	309
Commercial Building Optimization Program	0	0	0	0	0	0	0	151	113	125	82	471
New Buildings Program	0	0	0	0	0	0	1	16	84	96	127	324
Commercial Boiler Program	0	0	0	0	0	80	80	183	184	228	268	1,023
HVAC - CO2 Sensors	0	0	0	0	0	0	0	0	0	0	26	26
Power Smart Energy Manager Program	0	0	0	0	0	0	0	0	60	62	52	174
Subtotal	0	0	0	0	193	714	780	973	1,238	1,159	1,154	6,210
DISCONTINUED/COMPLETED												
Spray Valves	0	0	0	0	0	56	33	27	18	3	1	138
Subtotal	0	0	0	0	0	56	33	27	18	3	1	138
COMMERCIAL TOTAL	0	0	0	0	193	770	812	999	1,256	1,162	1,155	6,348
INDUSTRIAL												
Industrial Natural Gas Optimization Program	0	0	0	0	109	39	98	92	174	122	176	810
Subtotal	0	0	0	0	109	39	98	92	174	122	176	810
EFFICIENCY PROGRAMS SUBTOTAL	714	432	436	439	878	2,689	2,987	2,027	2,289	2,104	3,245	18,240
CUSTOMER SELF-GENERATION PROGRAMS												
BioEnergy Optimization Program	0	0	0	0	0	0	14	8	0	0	0	22
Support Costs	212	234	253	557	1,379	1,790	1,626	2,268	2,171	1,750	1,320	13,558
GRAND TOTAL	925	666	689	996	2,257	4,479	4,627	4,303	4,461	3,853	4,565	31,821

Note: May not add up due to rounding.

2012/13 PS Plan
Annual Program Incentive Costs
(2001/02 - 2011/12)
(000's in 2012 $)

	2001/02	2002/03	2003/04	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	Interim Estimate 2011/12	Cumulative Total 2011/12
RESIDENTIAL												
Home Insulation Program	0	0	0	0	220	1,405	2,345	2,280	2,600	1,802	1,617	12,268
Lower Income Energy Efficiency Program	0	0	0	0	0	0	24	80	582	338	0	1,025
New Home Program	0	0	0	0	0	0	0	0	0	425	48	473
Water and Energy Saver Program	0	0	0	18	44	67	94	0	75	87	438	823
Subtotal	0	0	0	18	264	1,472	2,463	2,360	3,257	2,652	2,103	14,589
CUSTOMER SERVICE INITIATIVES												
Power Smart Residential Loan Program	0	0	0	0	0	0	0	0	0	0	0	0
Residential Earth Power Program	0	0	0	0	0	0	0	0	0	0	0	0
ecoEnergy	0	0	0	0	0	0	0	0	0	0	0	0
Solar H2O Heater	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal	0	0	0	0	0	0	0	0	0	0	0	0
DISCONTINUED/COMPLETED												
Thermostat	0	0	0	0	342	1,102	1,770	2,974	1,404	15	0	7,606
High Efficiency Furnace & Boiler	0	0	0	0	0	89	39	21	0	0	0	149
Subtotal	0	0	0	0	342	1,190	1,809	2,995	1,404	15	0	7,755
RESIDENTIAL TOTAL	0	0	0	18	606	2,662	4,272	5,355	4,661	2,666	2,103	22,344
COMMERCIAL												
Commercial Insulation Program	0	0	0	0	0	345	1,439	1,194	812	1,010	1,512	6,312
Commercial Windows Program	0	0	0	0	0	0	0	44	84	54	938	1,120
Commercial Custom Measures Program	0	0	0	0	0	50	207	360	671	862	67	2,217
Commercial Water Heater Program	0	0	0	0	0	0	0	0	0	0	0	0
City of Winnipeg Power Smart Agreement	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Clothes Washers Program	0	0	0	0	0	0	0	0	0	0	0	0
Commercial Kitchen Appliance Program	0	0	0	0	0	0	0	8	33	20	20	81
Power Smart Shops	0	0	0	0	0	0	0	2	0	0	0	2
Commercial Building Optimization Program	0	0	0	0	0	0	0	0	0	76	39	115
New Buildings Program	0	0	0	0	0	0	0	0	1	2	75	78
Commercial Boiler Program	0	0	0	0	0	369	793	886	1,121	2,066	631	5,866
HVAC - CO2 Sensors	0	0	0	0	0	0	0	0	0	0	10	10
Power Smart Energy Manager Program	0	0	0	0	0	0	0	0	87	98	0	185
Subtotal	0	0	0	0	0	763	2,440	2,495	2,809	4,187	3,292	15,986
DISCONTINUED/COMPLETED												
Spray Valves	0	0	0	0	0	81	26	102	10	19	0	237
Subtotal	0	0	0	0	0	81	26	102	10	19	0	237
COMMERCIAL TOTAL	0	0	0	0	0	844	2,465	2,597	2,818	4,206	3,292	16,223
INDUSTRIAL												
Industrial Natural Gas Optimization Program	0	0	0	0	0	0	209	261	454	606	545	2,076
Subtotal	0	0	0	0	0	0	209	261	454	606	545	2,076
EFFICIENCY PROGRAMS SUBTOTAL	0	0	0	18	606	3,506	6,946	8,213	7,934	7,479	5,941	40,643
CUSTOMER SELF-GENERATION PROGRAMS												
BioEnergy Optimization Program	0	0	0	0	0	0	0	0	0	0	0	0
Support Costs	0	0	0	0	0	0	0	0	0	0	0	0
GRAND TOTAL	0	0	0	18	606	3,506	6,946	8,213	7,934	7,479	5,941	40,643

Note: May not add up due to rounding.

APPENDIX E - PROGRAM EVALUATION CRITERIA

NATURE OF ELECTRICITY AND NATURAL GAS MARKETS

PROGRAM CATEGORIES

ECONOMIC EFFECTIVENESS METRICS

OTHER DSM PROGRAM ASSUMPTIONS

APPENDIX E - PROGRAM EVALUATION CRITERIA

Manitoba Hydro's Power Smart programs take into account the underlying differences in the electricity and natural gas industries and the nature of the programs evaluated. Power Smart programs are assessed annually to ensure the individual programs as well as the overall portfolio of programs are cost-effective and meeting intended market transformation objectives and targets.

NATURE OF ELECTRICITY AND NATURAL GAS MARKETS

The nature of the electricity and natural gas markets are similar, however unique differences exist and need to be considered in Manitoba Hydro's Power Smart initiative.

For electricity, lower consumption in Manitoba and lower utility revenue is offset by higher revenues realized by selling the conserved energy in the export market. Lower electricity consumption also defers the need to invest in new transmission facilities that would be required to meet future domestic demand. Load management and certain types of demand response initiatives are also unique elements of electricity markets (e.g. short term price volatility creates opportunities for cost-effective load management and demand response initiatives). The combined effect results in an economic case for Manitoba Hydro to aggressively pursue electricity DSM in Manitoba.

With natural gas, lower consumption in Manitoba is offset by lower natural gas purchases from Alberta. In general, this is a one-to-one relationship as Manitoba Hydro passes the cost of primary natural gas and transportation through to its customers with no mark up on the commodity. Load management opportunities are generally not available in the natural gas market as these operational issues are handled through natural gas storage facilities.

PROGRAM CATEGORIES

CUSTOMER SERVICE PROGRAMS

Customer service programs are those programs offered as part of the overall Power Smart initiative that represent the customer service levels that would be expected of a utility. Customer service programs and services are assessed by the aggregate value realized by both the Corporation's customers and the Corporation. These assessments are undertaken on an on going basis and require a qualitative evaluation of the benefits. Service levels are then adjusted accordingly.

COST-RECOVERY PROGRAMS

Cost-recovery programs are those programs where the cost associated with the program is recovered from participating customers through fees or charges (e.g. interest rates). The cost-effectiveness of these programs is assessed annually with fees or charges adjusted accordingly.

FINANCIAL LOAN PROGRAMS

Financial Loan Programs assists participating customers in the installation and/or upgrade of energy efficient measures by offering low interest financing opportunities.

INCENTIVE BASED PROGRAMS

Incentive based programs are those programs where Power Smart uses a financial incentive to encourage customer participation. Assessments provide feedback on the success and cost-effectiveness of individual programs and the Power Smart portfolio. The results of these assessments drive program design and strategy modifications.

ENERGY EFFICIENT CODES & STANDARDS

In many markets, the most effective and permanent form of market transformation for energy efficient technologies and practices is the adoption of energy efficient codes and standards as it ensures that customers do not revert to less efficient technologies/practices once the incentives and/or promotional activities are discontinued. Consequently, the process of achieving these changes is complex and lengthy as it involves many stakeholders, varying environmental and market conditions and market acceptance.

Manitoba Hydro's strategy to affect change in codes and standards involves being an aggressive and active participant and in many cases, a driving force on a number of provincial and national energy efficiency codes and standards committees (e.g. Manitoba Hydro representatives often chair committees). The focus of Manitoba Hydro's efforts on these committees is towards developing new energy efficient technologies, developing energy efficient codes and standards and facilitating market acceptance of new technologies and building design practices.

ECONOMIC EFFECTIVENESS METRICS

Manitoba Hydro uses a number of cost effective metrics to assess energy efficient opportunities, including whether to pursue an opportunity, how aggressively an opportunity will be pursued, effectiveness of program design options and the relative investment from ratepayers and participants. In addition to quantitative assessments, Manitoba Hydro also considers various qualitative factors including equity (i.e. reasonable participation by various ratepayer sectors such as lower income) and overall contribution towards having a balanced energy conservation strategy and plan.

Quantitative assessments include using the following cost effective metrics:

- Marginal Resource Cost (MRC);
- Total Resource Cost (TRC);
- Rate Impact Cost (RIM);
- Levelized Utility Cost (LUC); and
- Simple Customer Payback calculation.

MARGINAL RESOURCE COST

The Marginal Resource Cost (MRC) metric is used as a preliminary and high level screen to assess the benefits associated with an energy efficient opportunity. This benefit/cost ratio is a simple assessment to determine whether the benefits that are associated with an energy efficient opportunity are greater than the costs. This assessment is undertaken irrespective of who realizes the benefits and who pays the costs. In addition, the assessment excludes any program administration costs (e.g. program planning, design, marketing, implementation and evaluation).

In general, if an opportunity offers greater benefits relative to costs, then a program for pursuing the opportunity should be considered, however Manitoba Hydro will also consider supporting certain programs where the benefits are less than the costs. In the latter case, the rationale driving the support will be driven by other qualitative factors such as supporting emerging technologies (e.g. solar panels). The Marginal Resource Cost metric is defined as follows:

$$\text{MRC} = \frac{\text{PV (Marginal Benefits)}}{\text{PV (Incremental Product Costs)}}$$

Where:

- For electricity, the Marginal Benefits includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market, the avoided cost of new infrastructure (e.g. electric transmission facilities) and measurable non-energy benefits (e.g. water savings);

- For natural gas, the Marginal Benefits includes Manitoba Hydro's avoided cost of purchasing natural gas, avoided transportation costs, the value of reduced greenhouse gas emissions (GHGs) and measurable non-energy benefits (e.g. water savings);

- Incremental Product Costs includes the total incremental cost associated with implementing an energy efficient opportunity. It is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program.

TOTAL RESOURCE COST

The Total Resource Cost (TRC) metric is a detailed assessment to determine whether the benefits that are associated with an energy efficiency program are greater than the costs. This assessment is undertaken irrespective of who realizes the benefits and who pays the costs with any economic transfers between the Corporation and the participating customer being excluded.

In general, if program offers greater benefits relative to costs, then a program for pursuing the opportunity should be considered, however Manitoba Hydro will also consider supporting certain programs where the benefits are less than the costs. In the latter case, the rationale driving the support will be driven by other qualitative factors such as supporting emerging technologies (e.g. solar panels) or targeting low participation market sectors (e.g. lower income). The Total Resource Cost metric is defined as follows:

$$TRC = \frac{\text{PV (Marginal Benefits)}}{\text{PV (Total Program Admin Costs + Incremental Product Costs)}}$$

Where:

- For electricity, the Marginal Benefits includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market, the avoided cost of new infrastructure (e.g. electric transmission facilities) and measurable non-energy benefits (e.g. water savings);
- For natural gas, the Marginal Benefits includes Manitoba Hydro's avoided cost of purchasing natural gas, avoided transportation costs, the value of reduced greenhouse gas emissions (GHGs) and measurable non-energy benefits (e.g. water savings);
- Total Program Admin Costs includes the administrative costs involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs;
- Incremental Product Costs includes the total incremental cost associated with implementing an energy efficient opportunity. It is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program.

SOCIETAL COST

The Societal Cost (SC) metric measures the net economic benefit as measured by the TRC, plus additional indirect benefits such the avoided environmental or societal externalities (e.g. reduced health care costs, increase productivity, employment) and "non-priced" benefits enjoyed by participants (improved comfort, improved heath).

$$SC = \text{TRC + Additional Indirect Benefits}$$

RATE IMPACT MEASURE

The Rate Impact Measure (RIM) metric is used to provide an indication of the long term impact of an energy efficient program on energy rates. The metric is a benefit/cost ratio that represents the economic impact of a program from the ratepayer's perspective. All program related savings and costs incurred by the utility, including revenue loss and incentive payments, are taken into account in this assessment. The Rate Impact Measure metric is defined as follows:

$$\text{RIM} = \frac{\text{PV (Utility Marginal Benefits)}}{\text{PV (Revenue Loss + Utility Program Admin Costs + Incentives)}}$$

Where:

- For electricity, the Utility Marginal Benefits includes the revenue realized by Manitoba Hydro from conserved electricity being sold in the export market and the avoided cost of new infrastructure (e.g. electric transmission facilities);
- For natural gas, the Utility Marginal Benefits includes Manitoba Hydro's avoided cost of purchasing natural gas and avoided transportation costs;
- Revenue Loss includes Manitoba Hydro's lost revenue associated with the participants' reduced energy consumption (i.e. customer energy bill reductions);
- Utility Program Admin Costs includes administrative costs incurred by Manitoba Hydro for staff involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs;
- Incentives include the funds transferred from Manitoba Hydro to the participant associated with implementing the Power Smart measure.

LEVELIZED UTILITY COST

The Levelized Utility Cost (LUC) is used to provide an economic cost value for the energy saved through an energy efficiency program. The LUC provides the total cost of the conserved energy on a per unit basis levelized over a fixed time period. The cost value allows for a comparison to other supply options and other DSM programs occurring over different timeframes. The Levelized Utility Cost is defined as follows:

$$LUC = \frac{PV\ (\text{Utility Program Admin Costs} + \text{Incentives})}{PV\ (\text{Energy})}$$

Where:

- Utility Program Admin Costs includes administrative costs incurred by Manitoba Hydro for staff involved in program planning, design, marketing, implementation and evaluation. It includes all costs associated with offering the Power Smart program, except for customer incentive costs;
- Incentives includes the funds transferred from Manitoba Hydro to the participant associated with implementing the Power Smart measure;
- Energy includes the annual energy savings.

CUSTOMER PAYBACK CALCULATION

The Customer Payback calculation provides the simple payback of implementing an energy efficient opportunity for customers. This value outlines the amount of time required before the customer recovers the incremental product cost. The value is useful in determining customer participation rates for energy efficient opportunities. The Customer Payback is defined as follows:

$$CP = \frac{\text{Participant Costs} - \text{Incentives}}{\text{Annual Bill Reductions}}$$

Where:

- Participant Costs includes the participant's total incremental cost associated with implementing the energy efficient opportunity, which is the difference in costs between the energy efficient technology and the standard technology that would have been installed in the absence of the program.
- Incentives includes funds provided by Manitoba Hydro and external parties to the participant associated with implementing the energy efficient opportunity;
- Annual Bill Reductions include the dollar reductions in the customer's electricity, natural gas, and water bills.

OTHER DSM PROGRAM ASSUMPTIONS

Market Transformation

Market transformation is a strategic intervention to achieve a lasting, significant share of energy efficient products and services in targeted markets. Manitoba Hydro's Power Smart strategy focuses on creating a sustainable market change where energy efficient technologies and practices become the market standard.

However, market transformation is difficult to measure. Manitoba Hydro has made significant progress in developing specific methodologies for measuring its impacts. Wherever possible, Manitoba Hydro has attempted to obtain sales/technology specific data to calculate a program's true effect. Difficulties arise in 1) obtaining sales data for areas outside of Manitoba for comparison purposes and in 2) obtaining sales information for Manitoba that fall outside of Power Smart program participation. In some instances, qualitative information is used to determine a program's impact on the market. Manitoba Hydro plans to continue work to further quantify and report on the influence of market transformation within the Manitoba marketplace.

For the 2012/13 Power Smart Plan, the DSM programs that have assumed a future level of market transformation have been noted.

Participant Reinvestment

Participant reinvestment is a marketing assumption which measures the program's influence on a participant's decision to repurchasing the energy efficient technology once the initial product life of the energy efficient technology has ended.

For the 2012/13 Power Smart Plan, the DSM programs that have assumed a future level of participant reinvestment have been noted.

Interactive Effects

Interactive effects are related to the impacts of implementing certain electric efficiency opportunities. As a consequence of implementing a more efficient technology, less heat is often produced. The interactive effect refers to the offsetting need to supplement heat as a result of implementing the energy efficient technology. For example, a CFL emits less heat than a traditional incandescent light bulb; therefore it will take more natural gas to heat the area after the CFL is installed. With the creation of natural gas DSM, electric DSM programs are required to quantify increases in natural gas usage due to interactive effects.

For the 2012/13 Power Smart Plan, electric DSM programs with natural gas interactive effects have been noted.

Section:	Main Filing Document	**Page No.:**	18 of 23
Topic:	Net Export Revenue and Net Income		
Subtopic:	Allocation of Net Export Revenue and Net Income		
Issue:	Basis of Allocation		

PREAMBLE TO IR (IF ANY):

In the second bulleted paragraph on the page referenced in the table above, Net Export Revenue allocation is justified in part that its methodology is the same as the allocation of Net Income.

QUESTION:

a) What is the rationale behind the allocation of net income on a total allocated cost basis among the classes?

b) Please list, describe, and discuss Manitoba Hydro's reasons for not selecting other options being considered by Manitoba Hydro, by Christensen Associates in its reports prepared for Manitoba Hydro, and by NERA in reports delivered in work associated with Manitoba since 2004 for the allocation of net export revenue.

RATIONALE FOR QUESTION:

Appropriateness of the allocation of Net Export Revue and Net Income costs.

RESPONSE:

a) Net income is not allocated among classes based on total allocated costs in the COSS, but on the basis of net investment. Allocating net income on this basis effectively treats net income as a return on investment, a cost most reasonably viewed as driven by the net investment of the utility.

b) Please see Manitoba Hydro's response to PUB/MH I-18a-h.

Section:	Main Filing Document	**Page No.:**	18 of 23
Topic:	Net Export Revenue and Net Income		
Subtopic:	Allocation of Net Export Revenue and Net Income		
Issue:	Basis of Allocation		

PREAMBLE TO IR (IF ANY):

In the second bulleted paragraph on the page referenced in the table above, Net Export Revenue allocation is justified in part that its methodology is the same as the allocation of Net Income.

QUESTION:

c) Please list, summarize, and provide any studies or analyses performed by or on behalf of Manitoba Hydro on establishing and maintaining the required levels of retained earnings and net income, including but not limited to analyzing Manitoba Hydro's need for working capital, variability of export revenues from year to year, and the variability of domestic revenues actually collected in any given year since 2004.

RATIONALE FOR QUESTION:

Appropriateness of the allocation of Net Export Revue and Net Income costs.

RESPONSE:

Manitoba Hydro retained KPMG to review Manitoba Hydro's financial targets and prepare a report which was filed with the PUB as part of the 2016/17 Supplemental Filing. As per confirmation from PUB counsel on April 12, 2016, this Information Request has been withdrawn as it will be reviewed by the PUB during the next full General Rate Application.

Section:	Main Filing Document	**Page No.:**	18 of 23
Topic:	Net Export Revenue and Net Income		
Subtopic:	Allocation of Net Export Revenue and Net Income		
Issue:	Basis of Allocation		

PREAMBLE TO IR (IF ANY):

In the second bulleted paragraph on the page referenced in the table above, Net Export Revenue allocation is justified in part that its methodology is the same as the allocation of Net Income.

QUESTION:

d) Please provide a comparison of the first two years of domestic load growth in total and by rate class in each forecast developed by or on behalf of Manitoba Hydro, comparing forecast to actual for those two years. Provide these comparisons for load forecasts developed since 2004.

RATIONALE FOR QUESTION:

Appropriateness of the allocation of Net Export Revue and Net Income costs.

RESPONSE:

Please see the following table which shows a comparison of the energy consumption forecast for the first two years of IFF11, IFF12 and IFF13 with actual non-weather normalized consumption experienced in the five fiscal years from 2010/11 through 2014/15 inclusive.

ACTUAL ENERGY CONSUMPTION (GWh)

	Residential	General Service								A&RL	Total
		Small ND	Small Demand	Med Demand	Lrg <30kV	Lrg 30-100	Lrg >100	Other GS	Total GS		
Actual Consumption*											
2010/11	7,060	1,595	1,924	3,057	1,632	972	4,402	42	13,624	103	20,786
2011/12	6,931	1,551	1,924	3,040	1,600	1,164	4,414	43	13,737	103	20,771
2012/13	7,334	1,628	2,016	3,086	1,644	1,222	4,398	46	14,040	103	21,477
2013/14	7,888	1,722	2,143	3,241	1,688	1,283	4,224	47	14,347	104	22,338
2014/15	7,788	1,697	2,107	3,207	1,705	1,433	4,372	44	14,566	104	22,458
Load Growth:											
2011/12	*(129)*	*(43)*	*(0)*	*(17)*	*(32)*	*193*	*11*	*1*	*113*	*0*	*(16)*
2012/13	*403*	*76*	*91*	*46*	*44*	*57*	*(15)*	*3*	*302*	*1*	*706*
2013/14	*554*	*94*	*127*	*155*	*44*	*61*	*(175)*	*1*	*307*	*0*	*861*
2014/15	*(100)*	*(25)*	*(35)*	*(33)*	*17*	*150*	*148*	*(3)*	*219*	*0*	*120*

*Actual energy consumption - Not weather normalized.

ACTUAL (NON WEATHER NORMALIZED) VS FORECAST (GWh)

	Residential	General Service (incl DSM)								A&RL	Total	
	(incl DSM)	Small ND	Small Demand	Med Demand	Lrg <30kV	Lrg 30-100	Lrg >100	Other GS	Total GS	(incl DSM)	(incl DSM)	
2011 Load Fcst (IFF11)												
2011/12	7,207	1,607	1,937	3,086	1,676	1,041	4,661	43	14,053	104	21,364	
2012/13	7,280	1,603	1,977	3,106	1,723	1,054	4,857	43	14,363	105	21,749	
Variance: Fcst vs Act												
2011/12	*277*	*56*	*13*	*46*	*77*	*(123)*	*248*	*(0)*	*316*	*1*	*593*	*2.9%*
2012/13	*(53)*	*(25)*	*(38)*	*20*	*79*	*(168)*	*459*	*(3)*	*324*	*1*	*272*	*1.3%*
2012 Load Fcst (IFF12)												
2012/13	7,325	1,601	1,985	3,143	1,679	1,221	4,645	44	14,319	104	21,748	
2013/14	7,419	1,591	2,049	3,176	1,703	1,328	4,916	44	14,807	105	22,330	
Variance: Fcst vs Act												
2012/13	*(9)*	*(27)*	*(30)*	*57*	*36*	*(1)*	*246*	*(2)*	*279*	*0*	*271*	*1.3%*
2013/14	*(469)*	*(131)*	*(94)*	*(65)*	*15*	*45*	*693*	*(3)*	*460*	*1*	*(8)*	*0.0%*
2013 Load Fcst (IFF13)												
2013/14	7,425	1,610	2,066	3,100	1,672	1,320	4,650	47	14,465	104	21,994	
2014/15	7,528	1,600	2,120	3,129	1,702	1,370	4,701	49	14,672	104	22,305	
Variance: Fcst vs Act												
2013/14	*(463)*	*(112)*	*(77)*	*(141)*	*(16)*	*38*	*427*	*0*	*119*	*0*	*(344)*	*-1.5%*
2014/15	*(259)*	*(97)*	*13*	*(79)*	*(2)*	*(63)*	*329*	*5*	*106*	*0*	*(153)*	*-0.7%*

Section:	Main Filing Document	**Page No.:**	21 of 23
Topic:	US Interconnections		
Subtopic:	Allocation of costs associated with the US Interconnections		
Issue:	Size of US Interconnection		

PREAMBLE TO IR (IF ANY):

Regarding the purpose of the investment in US Interconnections:

QUESTION:

a) Please provide a table of each major capital investment Manitoba Hydro has made to expand US Interconnection capacity. In this table please also list the in-service date of each project and total dollars invested in the project.

b) Please describe in detail the economic or reliability basis for each of the major investments made by Manitoba Hydro listed in part (a).

RATIONALE FOR QUESTION:

Appropriateness of the allocation of the costs of US interconnection.

RESPONSE:

The following table provides the major transmission interconnection investments undertaken by Manitoba Hydro since 1970 along with the rationale, and net book value of the investments to the extent available. As depicted in the table, these investments were undertaken to provide both reliable and low cost power to Manitobans. The interconnections facilitate the exchange of power between Manitoba Hydro, a winter peaking utility, and the U.S. which is summer peaking. The 500 kV line also provides an important access to power for Manitoba in the event the HVDC lines are lost.

Date	Project Name	Original Total Length (km)	Total Length of Interconnection Today (km)	2014 NBV ($ millions)	Max Export Capability at MH-US border	Max Import Capability at MH-US border	History Notes	Reason for Project
1970	L20D: Letellier (MB) to Drayton (ND)	232	61.7	$ 3.0	330	100	Line originally terminated between Winnipeg (LaVerendrye) and Grand Forks (Prairie). Letellier was constructed around 1977.	Construction of Grand Rapids (1965-1968). Agreement to exchange power with NSP, OTP and MPC. 90 MW of winter capacity purchased in 1970 rather than add another thermal plant at Selkirk.
1976	R50M: Richer (MB) to Moranville (MN)	186.8	123.5	$ 1.5	550	300	Line originally went from Ridgeway to Shannon with tap at Moranville.	Construction of Kettle (1974). Agreement to export firm and interruptible power to MP and MPC.
1980	M602F: Riel (MB) to Forbes (MN)	537.3	487.5	$ 31.3	1425	700	Line originally went from Dorsey to Forbes. Riel station added in 2014.	Long Spruce (1979). Addition of line more than doubled ability to exchange power with the US. The line allowed for a major sale of surplus power to NSP. Seasonal diversity was used to help provide economic justification for the line. The line was also recognized to improve reliability in case MH lost the HVDC.
1993	Manitoba Minnesota Phase 1, 500 kV Series Compensation (MN) and Dorsey station upgrades (MB)			see Note 1	1625	500	Added series capacitors to 500 kV line in the US. Added extra 230/500 kV transformer and shunt caps at Dorsey.	Capacity increase needed to provide a 400 MW increase in transfer capability. The driver was a 1989 diversity exchange agreement between MH and NSP and UPA that covered the period 1995 to 2014. MH would export an additional 400 MW to the US in the summer and import 400 MW in the winter.
1994	Manitoba Minnesota Phase 2, Static Var Compensator at Forbes (MN)			N/A – see Note 2	1800	500	Added SVC at Forbes station in US	Part of 1989 diversity exchange facility additions
1996	Manitoba Minnesota Phase 3, 230 kV shunt capacitors (MN)			N/A – see Note 2	1975	500	Addition of capacitors at several locations including Running, New Roseau County substation near R50M and Prairie near L20D.	Part of 1989 diversity exchange facility additions
2002	G82P: Glenboro (MB) to Peace Garden (ND)	170.9	83.3	$ 15.9	2175	700	Peace Garden station added in 2015	Limestone (1991). Line built primarily to firm up import capability to meet NSP's obligation of 500 MW but it also improved export capability. Surplus power from Limestone was exported to NSP over all US interconnections.

Note 1: these costs are included in the Dorsey 500 kV AC Switchyard which has a 2014 NBV of $32.8 million.

Note 2: these projects were undertaken by a US utility on the US side of the border but resulted in increased export capability for Manitoba Hydro.

Section:	Appendix 1	**Page No.:**	4 of 7
Topic:	Net Export Revenue		
Subtopic:	Allocation of Net Export Revenue		
Issue:	Basis of Allocation		

PREAMBLE TO IR (IF ANY):

In the last paragraph on the page referenced in the table above, Manitoba Hydro adopts the CA recommendation in that their current approach 'moderates the illogical effect of reducing some customer class revenue requirements below short run marginal costs.'

QUESTION:

a) Please provide the derivation of short-run marginal costs for each class affected including reports and spreadsheets. Please provide any spreadsheets in electronic format.

b) Please explain why a customer class should pay more than their allocated costs for electricity.

c) Why does Manitoba Hydro believe it is better to change the allocation methodology in the instance being discussed rather than make an adjustment to the specific class revenue target used in establishing rate design? Does the RCC become distorted by choosing a cost allocation methodology to justify higher rates in a particular class?

RATIONALE FOR QUESTION:

Appropriateness of the allocation of Net Export Revenue and Net Income costs.

RESPONSE:

a) Please see the schedule attached to this response. Manitoba Hydro has derived a short-run marginal cost of supply by class based on 2014/2015 actual SEP prices. The total volume-weighted cost by class is derived by multiplying the customer class energy usage in each time period with the short run marginal cost of supply for each respective period.

The total volume-weighted cost is divided by annual energy to derive a short-run marginal cost of supply at meter for each customer class.

b) Export revenues based on full market prices, which is in excess of embedded cost, is not a cost of providing service, therefore, there is no cost causative basis for the distribution of that excess among customer classes.

c) The allocation of appropriate costs to the export class and the allocation of the resulting net export revenues back to domestic classes does not result in distortions to the RCC.

Manitoba Hydro recommends the approach that first allocates an appropriate amount of embedded cost to exports (which defrays an appropriate portion of the responsibility of embedded cost for domestic customers) and then returns the residual NER to each class on the basis of total cost to serve. This approach provides each class with the same percentage reduction in overall embedded cost allocated. Manitoba Hydro views this option to be robust, objective, and transparent.

Modifying the target revenue-to-cost ratio for each class would require some basis for establishing the appropriate range of reasonableness on a class-by-class basis, which may be more controversial and less transparent than addressing the matter through a choice in cost allocation methodology.

Energy (MW.h) at Meter Weighted by SRMC

	Spring			Summer			Fall			Winter					
	Peak	**Shoulder**	**Off Peak**	**Peak**	**Shoulder**	**Off Peak**	**Peak**	**Shoulder**	**Off Peak**	**Peak**	**Shoulder**	**Off Peak**	**Total Energy at Meter (kWh)**	**Energy Weighted by SRMC ($ 000's)**	**Short Run Marginal Cost (¢/kWh)**
Residential	232,577,127	453,552,214	291,770,568	454,966,252	832,442,225	430,034,878	305,058,469	554,925,732	350,808,094	831,650,589	1,526,868,057	1,038,550,726	7,303,204,931	184,930	2.53
Residential FRWH	549,221	1,071,045	689,004	1,223,493	2,238,600	1,156,448	581,819	1,058,376	669,075	1,130,684	2,075,878	1,411,979	13,855,623	332	2.40
Residential Seasonal	3,684,450	7,185,102	4,622,183	8,698,558	15,915,569	8,221,892	3,436,386	6,251,061	3,951,741	6,224,602	11,428,052	7,773,174	87,392,769	2,057	2.35
GS Small Non-Demand	58,562,910	106,914,157	63,338,018	135,054,524	198,975,812	112,878,473	69,534,742	119,376,271	72,577,270	168,418,229	297,569,458	192,678,155	1,595,878,020	39,875	2.50
GS Small Non-Demand FRWH	202,747	370,141	219,279	478,781	705,388	400,165	210,652	361,645	219,869	405,108	715,764	463,462	4,753,000	115	2.42
GS Small Non-Demand Seasonal	270,614	494,040	292,679	786,518	1,158,777	657,371	151,397	259,916	158,021	166,373	293,956	190,338	4,880,000	109	2.22
GS Small Demand	74,602,994	134,899,660	83,440,912	163,501,913	264,253,066	157,521,248	90,290,805	156,935,025	98,544,009	207,666,024	369,936,690	246,122,222	2,047,714,567	50,572	2.47
GS Medium	123,156,861	219,302,432	134,789,803	278,713,633	448,538,299	271,863,155	138,244,702	238,049,504	147,938,139	302,286,223	527,536,007	344,242,954	3,174,661,713	77,419	2.44
GS Large 750-30kV	69,942,398	119,507,174	78,005,351	156,344,112	245,790,548	161,413,969	74,780,300	124,115,578	82,720,151	154,566,500	259,659,175	175,635,950	1,702,481,206	40,974	2.41
GS Large 30-100kV	38,214,231	75,630,681	58,342,845	80,225,784	151,514,390	117,662,699	42,441,910	81,810,207	64,120,768	88,638,794	171,110,939	133,569,881	1,103,283,129	25,906	2.35
GS Large 30-100kV Curtailable	8,429,777	16,917,878	12,695,537	16,964,909	32,809,241	24,964,885	8,617,396	16,737,926	12,720,969	16,464,953	32,197,823	24,405,660	223,926,954	5,195	2.32
GS Large > 100kV	106,564,967	210,145,358	162,547,442	199,550,333	370,279,294	291,773,919	110,719,855	213,535,797	166,424,496	229,534,551	438,521,538	341,185,381	2,840,782,931	66,835	2.35
GS Large >100kV Curtailable	75,741,041	151,173,651	115,370,904	154,021,359	296,156,760	228,629,359	76,470,035	149,678,045	114,698,682	157,237,741	308,001,898	235,779,300	2,062,958,776	48,113	2.33
Street Lights	-	3,818,509	9,395,543	401,948	7,134,583	18,841,329	2,914,126	5,727,764	11,455,528	6,833,122	11,505,772	22,458,864	100,487,088	2,080	2.07
Totals	792,499,337	1,500,982,042	1,015,520,068	1,650,932,117	2,867,912,553	1,826,019,790	923,452,595	1,668,822,847	1,127,006,813	2,171,223,493	3,957,421,006	2,764,468,046	22,266,260,707	544,513	2.45
2014/15 SEP prices ($/kWh)	**0.029**	**0.026**	**0.015**	**0.029**	**0.021**	**0.008**	**0.024**	**0.018**	**0.013**	**0.039**	**0.030**	**0.026**			

Section:	PCOSS14	**Page No.:**	
Topic:	Cost Allocations to Energy		
Subtopic:	Hydraulic Generation Cost Sharing		
Issue:	Hydraulic Generation Vintages		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide a detailed tabulation of MH's hydraulic generation fixed costs (Finance/OM&A/ Depreciation/Taxes) in PCOSS14, separately identifying these for:
   i. Winnipeg River G.S (6)
   ii. Saskatchewan River G.S.(1)
   iii. Upper Nelson G.S.(2)
   iv. Lower Nelson River G.S.(3)
   v. Burntwood River G.S. (1)

b) Indicate for each of the above river systems the unit fixed costs (¢/kWh) if costs are charged:1) to dependable firm energy only, and 2) if costs are charged to average energy output.

RATIONALE FOR QUESTION:

To understand the relative costs and function of MH's hydraulic generation.

RESPONSE:

a) Please see Manitoba Hydro's response to PUB/MH I-56.

b) Please find attached Manitoba Hydro Exhibit 101 from the 2012/13 & 2013/14 Electric General Rate Application for the unit fixed costs by generating facility flowing from PCOSS13 for 2012/13. This is the most current information available.

MANITOBA HYDRO

2012/13 & 2013/14 ELECTRIC GENERAL RATE APPLICATION

UNDERTAKING PROVIDED BY: V. WARDEN

Manitoba Hydro Undertaking #42

Manitoba Hydro to provide the unit costs for each existing generating station on Manitoba Hydro's system. Manitoba Hydro to also indicate what discount rate was used.

Response:

The table below (column 8) provides the unit embedded cost of each generation facility by energy based on expected flow conditions ("Unit Cost"). The table reflects the mathematical derivation of Unit Cost and does not reflect the value of the resource to Manitoba Hydro. The generation costs and forecast energy output in this analysis are consistent with those in Manitoba Hydro's Prospective Cost of Service Study for 2013 ("PCOSS13") based on IFF11-2. Under other than PCOSS13 assumed flow conditions, the Unit Cost is subject to change.

The Cost of Service Study ("COSS") includes all costs included in the Corporation's Revenue Requirement which are then functionalized as Generation, Transmission, Subtransmission, and Distribution Plant or Distribution Service.

Costs functionalized as Generation in the COSS include the total costs related to generation facilities including: mitigation, HVDC Transmission facilities (excluding Dorsey convertor station), and a share of communication facilities, administrative buildings and general equipment. Costs functionalized as Generation in the COSS but unrelated to operation of the stations such as DSM, power purchases, and diesel generation have been excluded from this cost analysis. The analysis also does not include the cost of networked AC transmission or any other costs not functionalized as generation in the COSS.

The cost of the Churchill River Diversion and HVDC facilities have been included in the costs of Kettle, Limestone and Long Spruce stations, while the cost of Lake Winnipeg

Regulation has been included in the costs of all Nelson River stations (Limestone, Long Spruce, Kettle, Jenpeg, and Kelsey).

Interest costs in the COSS include the total forecast finance expense, capital taxes, and contribution to reserves which are functionalized based on net rate base investment. Therefore the study does not use a discount rate per se; however the ratio of total interest costs to net rate base in the PCOSS13 equals 5.1%.

Forecast 2012/13 Unit Costs Based on PCOSS13

	Capital Cost (million$) (1)	2012/13 GWh (2)	Water Rentals ($/MWh) (3)	O&M ($/MWh) (4)	Fuel ($/MWh) (5)	Depreciation ($/MWh) (6)	Interest ($/MWh) (7)	Total Cost ($/MWh) (8)	Total Cost ($/MWh) – Dependable Flow (9)	Total Cost ($/MWh) – Maximum Flow (10)
Limestone	1,446	7,395	3.34	4.27	-	5.85	10.50	23.97	30.53	19.07
Long Spruce	511	5,920	3.34	4.27	-	4.01	5.51	17.13	22.59	13.99
Kettle	419	6,938	3.34	3.98	-	3.46	4.97	15.75	19.97	13.16
Jenpeg	258	822	3.34	14.04	-	6.55	10.32	34.25	39.90	25.44
Kelsey	327	1,981	3.34	5.70	-	3.96	7.92	20.92	23.13	20.92
Wuskwatim	1,337	970	3.34	8.32	-	19.55	50.04	81.25	98.08*	75.11*
Great Falls	176	891	3.34	9.70	-	5.01	6.21	24.27	37.55	21.80
McArthur Falls	51	363	3.34	10.08	-	3.20	3.91	20.53	30.48	16.62
Seven Sisters	130	977	3.34	6.13	-	3.11	4.49	17.06	24.79	14.37
Pine Falls	61	647	3.34	6.82	-	2.48	3.08	15.73	26.57	14.47
Pointe Du Bois	97	432	3.34	26.41	-	11.10	7.75	48.61	64.45	36.94
Slave Falls	133	460	3.34	12.12	-	7.78	13.99	37.22	63.29	30.45
Grand Rapids	256	1,417	3.34	10.89	-	5.50	10.46	30.20	32.17	24.60
Laurie River	21	54	3.34	56.80	-	20.84	15.19	96.18	128.67	66.00
Brandon	187	56	-	261.49	35.79	160.73	85.63	543.64	75.37	543.64
Selkirk	106	20	-	494.61	44.56	124.20	129.87	793.24	79.41	793.24
Brandon CT	143	35	-	66.45	118.46	193.97	102.52	481.41	71.66	481.41
System Average								25.24	36.78	20.90

*Note Wuskwatim unit costs under dependable and maximum flows reflect partial year costs and prorated energy output.

The costs in the table represent the direct costs of owning and operating each facility divided by the megawatt hours generated in that year. These costs include both fixed and variable costs attributable to each facility such as depreciation, interest and operating costs. The cost per megawatt hour could vary substantially year over year depending on the actual output of the facility which varies depending of factors such as demand, water conditions and market prices etc. The variability is especially true for the Thermal Plants (Brandon and Selkirk) which may have very low volumes in some years as they may be uneconomic or prohibited from operating due to legislation. Unit costs have also been presented using energy production under dependable (minimum) and maximum flow conditions (columns 9 and 10) to illustrate the range in Unit Costs that are possible. The total operating and maintenance (excluding fuel and water rentals), depreciation and interest costs in these calculations are assumed to be unchanged from those in the COSS, and do not represent full year costs in the case of Wuskwatim.

The Unit Cost by Generating Station provides useful information for examining the embedded cost for each Station and may, to some extent reflect the generation vintage (in some cases old plant has been refurbished and the Unit Cost will reflect both historical and current cost).

It is, however, necessary to provide some context regarding the Unit Cost output for Hydraulic and Thermal Generating Stations as shown in the table above when compared to Export Market price data and Domestic Rates. Hydraulic and Thermal plants have different cost structures. Hydraulic generating stations have high fixed costs that accrue regardless of the amount of energy generated by the plant. The variable cost of Hydraulic Generation is low, including only Water Rental Fees and variable Operating and Maintenance costs. The variable cost of Thermal Generating Stations, on the other hand, are dominated by fuel (variable) costs that are dependent on the amount of energy generated. For the purpose of making dispatch decisions and export sales Manitoba Hydro uses the incremental variable cost of generation, which excludes fixed operating, interest and depreciation costs, and not on embedded costs as reflected in the table above. For the purpose of setting Domestic Rates Manitoba Hydro uses embedded costs (which include the cost of the Transmission and Distribution systems) offset partially by export revenue. It is therefore inappropriate to compare the Unit Costs in the table above with Export Market prices and Domestic Rates given the differences in their cost structure.

Section:	PCOSS14	**Page No.:**	
Topic:	Cost Allocations to Energy		
Subtopic:	Hydraulic Generation Cost Sharing		
Issue:	Hydraulic Generation Vintages		

PREAMBLE TO IR (IF ANY):

QUESTION:

c) Confirm that under average year conditions, the Lower Nelson G.S.(s) contribute 50% of the dependable hydraulic generation and 77% of the non-dependable energy that goes to the opportunity market.

RATIONALE FOR QUESTION:

To understand the relative costs and function of MH's hydraulic generation.

RESPONSE:

Not confirmed.

Under average flow conditions, the contribution of generation from the Lower Nelson River cannot be specifically allocated in terms of either dependable hydraulic generation or opportunity export energy. Manitoba Hydro operates an integrated system in which all available resources are operated as required to meet the total of the firm Manitoba load and export obligations while providing for opportunity exports when beneficial, on a least cost basis while observing operational limitations. Under average flow conditions, hydraulic energy above that determined for dependable flow conditions does not translate on a one for one basis into opportunity export sales, but may also be used by the integrated Manitoba Hydro system to decrease thermal and import energy requirements.

Please refer to Manitoba Hydro's response to PUB/MH I-23b which provides additional information related to the Lower Nelson generation stations' contributions to total system dependable energy supply under dependable flow conditions.

Section:	PCOSS14	**Page No.:**	54; Schedule D3
Topic:	Cost Allocations to Energy		
Subtopic:	HVDC cost implications		
Issue:			

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Provide a detailed tabulation of MH's HVDC transmission facilities fixed costs (Finance/OM&A/Depreciation/Taxes) identifying separately the costs for:

   i. Bipole I & II Northern converter facilities.
   ii. Bipole I & II AC collectors
   iii. Bipole I & II transmission lines/towers
   iv. Bipole I & II southern converter at Dorsey.

b) Confirm that this HVDC system in average years transmits 13,780 GWh of dependable/firm energy (67%) and 6720 GWh of non-dependable energy (33%) to Dorsey Station incurring total transmission losses of 1800± GWh of which MH allocates 1100± GWh to firm energy and 700± GWh to non-firm energy.

c) Please provide the "dependable" GWh losses on the HVDC system in a dependable flow year on 13,780 GWh of transmitted energy, and confirm whether those losses would be approximately 800 GWh.

d) Confirm whether the incremental losses (on an I2R basis) in an average flow year compared to a dependable flow year are approximately 1000 GWh (average year losses of 1,800 GWh less dependable year losses of 800 GWh).

RATIONALE FOR QUESTION:

It is not clear how MH's PCOSS14 cost sharing of HVDC reflects the functional usage of Bipole I & II.

RESPONSE:

a) The following schedule of HVDC facilities costs is taken from the "Cost Details Transmission and Substation.xlsx" Excel document provided on March 16, 2016.

	Finance Expense	Capital Tax	Total Interest Expense	Depreciation	Operating	Total Cost
Northern Converter Facilities						
Radisson Conv. Stn.	5,658,646	733,873	6,392,519	12,791,646	15,511,077	34,695,242
Henday Conv. Stn.	3,737,848	480,799	4,218,647	12,508,036	9,898,753	26,625,436
Henday 230 kV Switchyard	1,310,808	168,031	1,478,839	1,034,509	446,496	2,959,845
Radisson 138 kV Switchyard	407,749	52,178	459,927	386,291	454,631	1,300,849
Norther AC Collector Facilities						
Limestone-Henday 230 kV AC T/L	96,010	12,372	108,381	50,088	-	158,469
Long Spruce-Radisson 230 kV AC T/I	126,592	16,222	142,814	123,877	301,659	568,350
Long Spruce-Henday 230 kV AC T/L	178,069	22,801	200,870	162,479	221,462	584,811
Kettle-Radisson 138 kV AC T/L	3,920	505	4,425	26,254	273,700	304,379
Bipoles I & II	4,532,409	582,872	5,115,281	3,112,912	3,144,629	11,372,822
Southern Converter Facilities						
Dorsey Conv. Stn.	12,468,058	1,619,643	14,087,701	26,097,926	20,445,135	60,630,762

b) Not confirmed. The average generation of the Lower Nelson stations is estimated as 20840 GWh, and the HVDC losses are estimated as 1530 GWh, for a net delivery of 19310 GWh to Dorsey via the HVDC system (Bipoles I and II), as calculated based on hourly historic generation levels reduced by transmission losses, assuming all HVDC equipment is in service.

Transmission losses on the HVDC system were estimated assuming that all HVDC equipment is in service, and can vary significantly if components are out of service. Loss estimates are based on both fixed and variable (I^2R) losses, and reflect expected hourly generation of the lower Nelson plants throughout the year.

Manitoba Hydro does not "allocate" losses to either firm or non-firm energy, but rather compares available generation to existing loads, and operates in the most cost effective manner. The functional usage of the HVDC system requires meeting both the energy and capacity requirements of the Manitoba load and dependable exports.

c) The value of 20480 GWh average energy (and the 13780 GWh of dependable energy) from the Lower Nelson Plants appears to be based on Manitoba Hydro's response to PUB/MH I-042a Revised from the NFAT. This estimate of generation and associated HVDC losses reflects the average annual generation and associated calculated losses based on a sample of historical hourly operating records of the lower Nelson generation. Hourly operation rather than monthly average operation is required to estimate transmission losses. The dependable energy of 13780 GWh cited in that response reflects an adjustment of the historic hourly operation to approximate operation under dependable flows. The dependable energy attributable to the lower Nelson Plants is 15030 GWh, and the estimated HVDC losses should be about 990 GWh resulting in about 14040 GWh delivered to Dorsey during dependable flows.

   If 13780 GWh were to be delivered to Dorsey, it is estimated that the associated losses would be approximately 960 GWh, and is subject to variations based on generation and load patterns.

d) Not confirmed. The estimated transmission losses associated with average HVDC generation levels is 1530 GWh, and the estimated transmission losses associated with dependable HVDC generation levels is 990 GWh for a difference of 540 GWh, based on expected performance of the HVDC system with all components in service. Loss estimates include both fixed or constant losses, and variable or I^2R losses. Losses can vary considerably due to actual system loadings, or equipment outages.

Section:	PCOSS14	**Page No.:**	54; Schedule D3
Topic:	Cost Allocations to Energy		
Subtopic:	HVDC cost implications		
Issue:			

PREAMBLE TO IR (IF ANY):

QUESTION:

e) Please explain whether only the "dependable" losses related to dependable energy (approximately 800 GWh) should be allocated to dependable/firm energy in the PCOSS, and whether the incremental losses related to opportunity energy (approximately 1000 GWh) should be allocated to opportunity energy in the PCOSS.

RATIONALE FOR QUESTION:

It is not clear how MH's PCOSS14 cost sharing of HVDC reflects the functional usage of Bipole I & II.

RESPONSE:

Manitoba Hydro operates an integrated system and is not able to distinguish export power flows through the HVDC system vs. that which flows through the AC networked system. It is, therefore, unable to distinguish export losses specific to the HVDC system.

Please see Manitoba Hydro's responses to PUB/MH I-63c and PUB/MH I-2.

Section:	2014/15 & 2015/16 GRA PUB/MH II-63	**Page No.:**	
Topic:	Exports into MISO 2013/14, 2014/15 & 2015/16		
Subtopic:	7x16 Sales		
Issue:			

PREAMBLE TO IR (IF ANY):

Attached table of MISO export sales breakdown illustrates exports achieved in 2014/15.

QUESTION:

a) Please update the attached table by providing the same breakdown for 2013/14 and 2015/16.

b) Confirm that in July and August of 2014/15 MH achieved approximately 900 GWh of 7x16 sales which corresponds to full utilization of the U.S. tie-line's 1850 MW capacity.

c) Explain the market constraints that preclude that level of sales in the other summer months of June and September.

U.S. (and Canadian) Export Sales Breakdown (NEB Reporting)

		Firm Contract		Non-Firm	Total	Non-Firm	Total		Non-Firm	Non-firm	Total	Total	
		5x16		5x16	5x16	2x16	7x16 w/o losses		7x8	CDN 7x8	7x8	7x24 w/o losses	
		GWh		GWh	GWh	GWh	GWh		GWh	GWh	GWh	GWh	GWh
2013	Apr	276	572									631	1392
	May	296										761	
	Jun	324	1411									1176	4712
	Jul	401										1357	
	Aug	382										1284	
	Sep	304										955	
	Oct	343	605									1096	1669
	Nov	262										573	
	Dec	190	766									280	1323
2014	Jan	202										293	
	Feb	163										269	
	Mar	211				0						481	
①	Apr	264	537	182	446	132	578		112	64	176	754	1630
	May	273		159	432	146	578		195	103	298	876	
	Jun	406	1700	238	644	187	831		320	76	396	1027	4750
	Jul	460		232	692	201	893		373	80	453	1346	
	Aug	451		206	661	239	900		398	60	458	1358	
	Sep	383		181	564	141	705		253	61	314	1019	
	Oct	182	342	30	212	43	255		87	95	182	437	1077
	Nov	160		126	286	111	397		150	93	243	640	
	Dec	184	696	106	290	114	404		103	87	190	594	2180
2015	Jan	176		118	294	102	396		73	77	150	546	
	Feb	160		49	209	27	236		15	12	87	323	
	Mar	176		168	354	119	473		142	102	244	717	
	Apr	177	416									849	1903
	May	239										1054	
	Jun	233	949									981	3994
	Jul	248										953	
	Aug	228										1113	
	Sep	240										974	
	Oct	217	311									852	1495
	Nov	94										643	
	Dec	102										555	
2016	Jan	101										326	
	Feb												

①2014/15 data from the 2014/15 GRA PUB/MH II-63 and Appendix 9.1 Revised (Apr 30/15)

RATIONALE FOR QUESTION:

To understand the functional usage of the U.S. tie-line capacity.

RESPONSE:

a)

Year	Month	US Firm Contracts GWh	US Non Firm 5 x 16 GWh	US Non Firm 2 x 16 GWh	US Non Firm 7 x 8 GWh	CDN Sales GWh
2013	April	275	172	109	74	57
	May	295	367	191	249	35
	June	324	309	257	338	22
	July	401	316	219	421	30
	August	462	268	237	398	101
	September	304	216	176	259	76
	October	343	274	161	318	75
	November	262	112	79	120	82
	December	189	47	34	9	48
2014	January	200	54	20	17	49
	February	163	57	29	20	70
	March	211	138	87	44	77
	April	264	182	132	112	64
	May	273	159	146	195	103
	June	406	238	187	320	76
	July	460	232	201	373	80
	August	451	206	239	398	60
	September	383	181	141	253	61
	October	182	30	43	87	95
	November	160	126	111	150	92
	December	184	106	114	103	87
2015	January	176	118	102	73	77
	February	160	49	27	15	72
	March	176	168	119	142	102
	April	176	302	148	221	39
	May	349	295	158	254	49
	June	355	226	127	273	44
	July	377	243	111	222	63
	August	332	288	188	303	49
	September	363	253	91	239	47
	October	328	134	104	231	116
	November	118	263	135	127	69
	December	126	231	91	106	78
2016	January	126	94	75	31	83
	February	126	161	108	84	63

b) Manitoba Hydro cannot confirm that in July and August of 2014 US export sales were approximately 900 GWh of 7x16 sales. This is because energy sales under firm contracts include sales outside of the 7x16 timeframe. Further, the U.S. tie-line's scheduling limit is 1950 MW and not 1850 MW.

c) Market constraints rarely impacted energy deliveries during June and September, 2015. Rather lower sale volumes were mainly the result of generation and transmission outages in Manitoba.

Section:	as indicated in the 2015/16 Resource Planning Assumptions and Analysis document.	**Page No.:**	
Topic:	Hydraulic Generation Resources		
Subtopic:	Planning Assumption vs Utilization		
Issue:			

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Contrast and explain MH's original planning assumptions relative to the current utilization of hydraulic generation output under average year conditions:

	Planned	Utilization	
- Winnipeg R. G.S (6)	100% Domestic (?)	80% Domestic/ Firm export	20% Opportunity Export
- Saskatchewan R. G.S. (1)	100% Domestic (?)	90% Domestic/ Firm export	10% Opportunity Export
- Upper Nelson R. G.S. (2)	100% Domestic (?)	72% Domestic/ Firm export	28% Opportunity Export
- Lower Nelson R. G.S. (3)	?% Domestic (?)	?% Domestic/ Firm export	33% Opportunity Export
- Burntwood R. G.S. (1)	?% Domestic (?)	?% Domestic/ Firm export	15% Opportunity Export

b) Compare the expected Keeyask G.S. average year output utilization with the other three Lower Nelson River G.S.(s) (Kettle/Long Spruce/Limestone).

RATIONALE FOR QUESTION:

To understand the usage of the hydraulic generating stations between domestic load and export sales.

RESPONSE:

Response to parts a) and b):

The rationale for this question is to understand the usage of the hydraulic generating stations between domestic load and export sales. Manitoba Hydro plans and develops the Manitoba Hydro system ultimately to serve Manitoba load and provide a least cost supply of power to Manitoba Hydro customers over the long term. Manitoba Hydro operates an integrated system in which all available resources are operated as required to meet the total of the Manitoba load and export obligations, which will change over time depending on load growth and available system supply. As explained in Manitoba Hydro's response to PUB/MH I-25a-c, Manitoba Hydro's system is developed based on an energy planning criteria related to dependable flow conditions and a capacity planning criteria related to peak load demands and capacity planning reserve margins. The total system capacity is required to meet peak load demands, however, there will be surplus energy available under higher than dependable flow conditions and, subject to equipment outages, surplus capacity available during non-peak load conditions. During non peak load conditions, Manitoba Hydro uses resources to generate electricity, provided surplus water is available, to obtain opportunity export revenues.

Section:	COSS PUB/MH I-52; NFAT Business Case	**Page No.:**	
Topic:	Keeyask Business Case		
Subtopic:	Anticipated Firm Sales		
Issue:			

PREAMBLE TO IR (IF ANY):

Further to COSS PUB/MH I-52 and the NFAT economic justification for Keeyask G.S., the economic justification included both firm and opportunity sales revenues, with a portion of the firm sales under yet to be determined contracts.

QUESTION:

a) Provide a listing of the firm contract sales that were used to support the Keeyask business case for the 2021/22 to 2034/35 period.

b) Provide MH's anticipated additional contract sales for the 2021/22 to 2034/35 period. If there were no specific contracts anticipated, please provide the anticipated contract volumes that were used to support the Keeyask business case, differentiated by firm and non-firm, for 5x16, 2x16, and 7x8 periods for each year.

RATIONALE FOR QUESTION:

To understand how the planned firm sales for Keeyask differ from the PCOSS14/PCOSS14 Amended treatment of sales during the 5 x 16 and 2 x 16 time periods.

RESPONSE:

a) None of the sales agreements that formed part of the Keeyask business case fall within the timeframe associated with PCOSS14 or PCOSS14-Amended as they related to fiscal 2013/14 as anticipated in IFF12.

The following list of contracts were used to support the Keeyask business case:

MP 250 MW System Power Sale
MP 250 MW Energy Exchange
NSP 125 MW System Power Sale
WPS 100 MW System Power Sale

b) Subsequent to the Keeyask business case MH has completed sales agreements with SaskPower for 25 MW of System Power and 100 MW of System Power. Neither of these agreements fall within the timeframe associated with PCOSS14 or PCOSS14-Amended as they related to fiscal 2013/14 as anticipated in IFF12.

Section:	COSS PUB/MH I-52; NFAT Business Case	**Page No.:**	
Topic:	Keeyask Business Case		
Subtopic:	Anticipated Firm Sales		
Issue:			

PREAMBLE TO IR (IF ANY):

Further to COSS PUB/MH I-52 and the NFAT economic justification for Keeyask G.S., the economic justification included both firm and opportunity sales revenues, with a portion of the firm sales under yet to be determined contracts.

QUESTION:

c) Explain how the planned and anticipated firm sales after Keeyask enters service would fit into the PCOSS14 or PCOSS14 Amended definitions of firm and opportunity sales and whether these post-Keeyask sales would be excluded from fixed cost allocations to the Export class.

RATIONALE FOR QUESTION:

To understand how the planned firm sales for Keeyask differ from the PCOSS14/PCOSS14 Amended treatment of sales during the 5 x 16 and 2 x 16 time periods.

RESPONSE:

Additional dependable energy surplus to the needs of domestic customers with Keeyask in service will not be excluded from fixed cost allocations to dependable exports. Additional dependable energy will form part of the COS determination of dependable energy calculation and allocated a full share of embedded generation and transmission.

As discussed in Manitoba Hydro's Submission (page 16), for cost of service purposes, Manitoba Hydro does not intend to review export contracts to avoid the complexities associated with the classification of specific export sales. The derivation of dependable export flows in COS is based on forecasted energy surplus to the needs of domestic

customers in dependable flow conditions. This is assumes that all dependable energy above domestic requirements is sold as firm. Surplus energy available in average flow conditions (less the dependable portion) is assumed to be opportunity sales to calculate the dependable vs. opportunity split.

Please also Manitoba Hydro's response to COALITION/MH I-21d-e.

Section:	PCOSS14	**Page No.:**	Schedule D-1
Topic:	HVDC Demand Allocation		
Subtopic:	2CP vs Weighted Energy		
Issue:	Fixed Cost Drivers		

PREAMBLE TO IR (IF ANY):

MH employs a 2CP demand allocation based on 50 winter and 50 summer hourly system peaks for Transmission cost allocations but not for Generation cost allocations. It appears that the HVDC investments are demand-driven, not energy-driven.

QUESTION:

a) Explain why the 2CP demand allocation is not appropriate for the HVDC transmission system.

b) Provide a table that shows the 2CP allocators, weighted energy allocators, and dollars allocated based on each of 2CP and weighted energy for HVDC assets (including Dorsey and Riel).

RATIONALE FOR QUESTION:

To understand the rationale for classification and allocation of HVDC assets.

RESPONSE:

a) Investment in HVDC facilities have been driven by Manitoba Hydro's statutory obligation to ensure the availability of a supply of power adequate to meet both the energy and demand needs of the Province. The HVDC transmission system is an integral component of Manitoba Hydro's northern hydroelectric system. Its functionalization as generation and use of a weighted-energy allocator, that reflects both energy and demand components, recognizes that the role of the HVDC facilities is to move energy from remote generation to the backbone transmission system 8,760 hours of the year, not just in peak hours.

Furthermore, Manitoba Hydro believes that it would be inappropriate to differentiate the allocation methods for the HVDC facilities and the hydraulic generators for which they carry energy given that in absence of the generators there would be no need for those facilities.

b) Please see the table below, the analysis of which is based on PCOSS14-Amended. Both Bipole III and Riel (Converter Station) have been excluded as they are not yet in service.

	Weighted Energy Allocator Shares	2CP Allocator Shares	Weighted Energy Costs ($ 000)	2CP - Allocated Costs ($ 000)	Difference ($ 000)
Residential	29.2%	32.8%	40,678	45,714	5,036
GSS Non-Demand	6.3%	7.0%	8,823	9,759	936
GSS Demand	7.9%	8.3%	11,037	11,534	496
GSM	12.2%	12.7%	16,976	17,703	727
GSL 0-30 kV	6.4%	6.6%	8,951	9,145	195
GSL 30-100kV	4.7%	4.1%	6,476	5,668	(808)
GSL >100	16.9%	14.3%	23,561	19,847	(3,713)
A&RL	0.3%	0.2%	414	297	(117)
Export	16.0%	14.0%	22,287	19,535	(2,752)
Total	100.0%	100.0%	139,201	139,201	

Section:	MFR17 December 12, 2014 Generation & Transmission Treatment	**Page No.:**	Slides 11 & 14
Topic:	Functionalization of Rate Base		
Subtopic:			
Issue:	Changes in Rate Base – Impact on COSS		

PREAMBLE TO IR (IF ANY):

MH indicates in slide 14 of its December 14, 2014 presentation an increase in Rate Base reflecting the addition of Bipole III and Keeyask.

The addition of capital-intensive Keeyask and BPIII will not only increase the amount of rate base-related costs in the revenue requirement, but also change the allocation of interest between functions.

QUESTION:

a) Please provide the detail of the functionalization of Rate Base (in millions of dollars) reflected in slide 14 of the presentation for 2013/14 for PCOSS14 Amended.

b) Please provide the detail in slide 14 of the functionalization of Rate Base as in part (a) for 2017/18 and 2021/22.

c) Please provide the detail of the functionalization of Rate Base (in millions of dollars) prepared on a similar basis as schedules C-1 to C-8 that represents the Rate Base in each of the years 2017/18 and 2021/22, based on IFF15.

RATIONALE FOR QUESTION:

To understand the changes in Rate Base and how it may impact PCOSS.

RESPONSE:

Please see Manitoba Hydro's response to PUB/MH I-70a-c for the estimated potential changes in the allocation of Interest between functions.

Section:	MFR17 December 12, 2014 Generation & Transmission Treatment	**Page No.:**	Slides 11
Topic:			
Subtopic:			
Issue:	Allocation of Revenue Requirement		

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please provide the detail of revenue requirement and rate base by function on a similar basis as slide 11 from MH's December 12, 2014 presentation (PUB MFR 17) for PCOSS 14 Amended.

b) Please provide a similar level of detail as in (a) for forecast revenue requirement and rate base in 2017/18, and 2021/22 based on IFF15.

c) Please provide a reconciliation of each component of revenue requirement requested in (b) similar to that provided in MIPUG MFR 2. In each case, please explain the reason for the adjustment.

RATIONALE FOR QUESTION:

To understand the changes in revenue requirement from that used in PCOSS14 Amended

RESPONSE:

a) The schedule below provides the functional cost detail flowing from PCOSS14-Amended. Given that rate base drives the allocation of Interest in Cost of Service, which includes Finance Expense, Capital Tax and Net Income, Interest has been provided below.

PCOSS14-Amended Functionalized Revenue Requirement ($ 000's)

	Interest	Depreciation	Operating	Revenue Requirement
Existing Generation	286,881	137,464	153,816	578,161
Existing HVDC incl Dorsey Convertor Station	31,753	55,931	49,900	137,584
AC Collector incl Switching Stations	717	811	1,125	2,653
Coal GS	2,286	8,894	18,060	29,240
Natural Gas GS	7,609	9,622	15,092	32,323
Diesel GS	991	1,566	6,804	9,361
Water Rentals	-	-	107,741	107,741
Fuel and Power Purchases	-	-	90,296	90,296
Wind Purchases	-	-	64,996	64,996
NEB	-	-	964	964
Trading Desk	-	1,228	11,775	13,003
Uniform Rates	23,532	-	-	23,532
Existing DSM/AEF	8,253	43,240	889	52,381
Total - Generation	**362,021**	**258,755**	**521,458**	**1,142,235**
Transmission	55,780	37,942	50,293	144,015
Existing US Interconnection	2,597	1,281	807	4,684
MISO Fees	-	-	4,071	4,071
Total - Transmission	**58,377**	**39,223**	**55,171**	**152,770**
Subtransmission	21,455	20,004	22,838	64,296
Total - Subtransmission	**21,455**	**20,004**	**22,838**	**64,296**
Distribution Substation	21,797	26,313	36,101	84,211
Distribution Lines	59,620	43,141	38,161	140,922
Distribution Serialized Equipment	11,280	11,974	4,125	27,378
Distribution Services	3,155	2,283	2,019	7,456
Distribution Meter	1,702	4,197	2,188	8,087
Area & Roadway Lighting Dedicated	3,547	3,926	7,850	15,324
Distribution Diesel	58	85	444	587
Total - Distribution Plant	**101,160**	**91,918**	**90,888**	**283,965**
Cust Service - General	2,330	5,570	38,661	46,561
Cust Acct - Billings	1,455	2,607	24,147	28,210
Cust Acct - Collections	956	1,413	15,873	18,242
Marketing - R & D	42	53	690	784
Inspection	186	546	3,092	3,824
Meter Reading	631	879	10,467	11,976
Total - Distribution Services	**5,600**	**11,068**	**92,929**	**109,597**
Total Revenue Requirement	**548,612**	**420,968**	**783,284**	**1,752,864**

b) Please see the schedules below. Tables 1 and 2 provide a summary of the analysis, detailed schedules are provided thereafter. IFF15, as well as the revenue requirement by project identified in response to PUB/MH I-71e was used to provide the directional cost of service impacts of the new generation and transmission investment requested.

Table 1:

PCOSS14-Amended Functionalized Revenue Requirement ($ 000's)

	Interest	Depreciation	Operating	Revenue Requirement
Generation	362,021	258,755	521,458	1,142,235
Transmission	58,377	39,223	55,171	152,770
Subtransmission	21,455	20,004	22,838	64,296
Distribution Plant	101,160	91,918	90,888	283,965
Distribution Service	5,600	11,068	92,929	109,597
Total Revenue Requirement	**548,612**	**420,968**	**783,284**	**1,752,864**

Estimate of 2017/18 Functionalized Revenue Requirement ($ 000's)

	Interest	Depreciation	Operating	Revenue Requirement
Generation	495,427	283,986	576,248	1,355,661
Transmission	88,343	46,652	60,967	195,962
Subtransmission	26,220	19,712	25,237	71,170
Distribution Plant	123,627	90,579	100,438	314,644
Distribution Service	6,843	10,907	102,693	120,443
Total Revenue Requirement	**740,461**	**451,836**	**865,583**	**2,057,880**

Estimate of 2021/22 Functionalized Revenue Requirement ($ 000's)

	Interest	Depreciation	Operating	Revenue Requirement
Generation	964,228	532,710	651,635	2,148,572
Transmission	141,153	77,399	81,606	300,157
Subtransmission	20,637	21,623	26,743	69,004
Distribution Plant	97,305	99,361	106,431	303,098
Distribution Service	5,386	11,965	108,821	126,172
Total Revenue Requirement	**1,228,710**	**743,058**	**975,236**	**2,947,004**

Table 2:

PCOSS14-Amended Functionalized Revenue Requirement (%)

	Interest	Depreciation	Operating	Revenue Requirement
Generation %	20.7%	14.8%	29.7%	65.2%
Transmission %	3.3%	2.2%	3.1%	8.7%
Subtransmission %	1.2%	1.1%	1.3%	3.7%
Distribution Plant %	5.8%	5.2%	5.2%	16.2%
Distribution Service %	0.3%	0.6%	5.3%	6.3%
Total Revenue Requirement %	**31.3%**	**24.0%**	**44.7%**	**100.0%**

Estimate of 2017/18 Functionalized Revenue Requirement (%)

	Interest	Depreciation	Operating	Revenue Requirement
Generation %	24.1%	13.8%	28.0%	65.9%
Transmission %	4.3%	2.3%	3.0%	9.5%
Subtransmission %	1.3%	1.0%	1.2%	3.5%
Distribution Plant %	6.0%	4.4%	4.9%	15.3%
Distribution Service %	0.3%	0.5%	5.0%	5.9%
Total Revenue Requirement %	**36.0%**	**22.0%**	**42.1%**	**100.0%**

Estimate of 2021/22 Functionalized Revenue Requirement (%)

	Interest	Depreciation	Operating	Revenue Requirement
Generation %	32.7%	18.1%	22.1%	72.9%
Transmission %	4.8%	2.6%	2.8%	10.2%
Subtransmission %	0.7%	0.7%	0.9%	2.3%
Distribution Plant %	3.3%	3.4%	3.6%	10.3%
Distribution Service %	0.2%	0.4%	3.7%	4.3%
Total Revenue Requirement %	**41.7%**	**25.2%**	**33.1%**	**100.0%**

Estimate of 2017/18 Functionalized Revenue Requirement ($ 000's)

	Interest	Depreciation	Operating	Revenue Requirement
Existing Generation	350,599	135,461	169,977	656,037
Existing HVDC incl Dorsey Convertor Station	38,805	55,117	55,143	149,065
AC Collector incl Switching Stations	876	799	1,243	2,918
Coal GS	2,793	8,765	19,958	31,516
Natural Gas GS	9,299	9,482	16,678	35,458
Diesel GS	1,211	1,543	7,519	10,273
Water Rentals	-	-	119,061	119,061
Fuel and Power Purchases	-	-	99,783	99,783
Wind Purchases	-	-	71,825	71,825
NEB	-	-	1,065	1,065
Trading Desk	-	1,210	13,012	14,222
Uniform Rates	28,759	-	-	28,759
Existing DSM/AEF	10,086	42,610	982	53,678
BP III and Riel Convertor Station	-	-	-	-
Keeyask GS	-	-	-	-
Additional DSM	9,000	12,000	1,000	22,000
Pointe du Bois: Spillway	33,000	9,000	(1,000)	41,000
Conawapa: Financing of Sunk Costs	11,000	8,000	-	19,000
Total - Generation	**495,427**	**283,986**	**576,248**	**1,355,661**
Transmission	68,170	37,390	55,577	161,136
Existing US Interconnection	3,173	1,262	892	5,327
MISO Fees	-	-	4,499	4,499
MMTP/GNTL	-	-	-	-
Riel 230/500 kV Station	17,000	8,000	-	25,000
Total - Transmission	**88,343**	**46,652**	**60,967**	**195,962**
Subtransmission	26,220	19,712	25,237	71,170
Total - Subtransmission	**26,220**	**19,712**	**25,237**	**71,170**
Distribution Substation	26,638	25,929	39,894	92,462
Distribution Lines	72,862	42,513	42,171	157,545
Distribution Serialized Equipment	13,785	11,799	4,558	30,142
Distribution Services	3,855	2,249	2,231	8,336
Distribution Meter	2,080	4,136	2,418	8,634
Area & Roadway Lighting Dedicated	4,335	3,869	8,675	16,879
Distribution Diesel	71	84	490	645
Total - Distribution Plant	**123,627**	**90,579**	**100,438**	**314,644**
Cust Service - General	2,847	5,489	42,723	51,059
Cust Acct - Billings	1,778	2,569	26,684	31,032
Cust Acct - Collections	1,169	1,392	17,541	20,102
Marketing - R & D	51	52	762	865
Inspection	228	538	3,417	4,182
Meter Reading	771	866	11,566	13,203
Total - Distribution Services	**6,843**	**10,907**	**102,693**	**120,443**
Total Revenue Requirement	**740,461**	**451,836**	**865,583**	**2,057,880**

Estimate of 2021/22 Functionalized Revenue Requirement ($ 000's)

	Interest	Depreciation	Operating	Revenue Requirement
Existing Generation	275,951	148,595	180,121	604,667
Existing HVDC incl Dorsey Convertor Station	30,543	60,461	58,434	149,437
AC Collector incl Switching Stations	689	876	1,318	2,883
Coal GS	2,199	9,614	21,149	32,962
Natural Gas GS	7,319	10,401	17,673	35,393
Diesel GS	953	1,693	7,968	10,614
Water Rentals	-	-	126,166	126,166
Fuel and Power Purchases	-	-	105,738	105,738
Wind Purchases	-	-	76,111	76,111
NEB	-	-	1,129	1,129
Trading Desk	-	1,327	13,788	15,116
Uniform Rates	22,636	-	-	22,636
Existing DSM/AEF	7,939	46,741	1,041	55,721
BP III and Riel Convertor Station	168,000	91,000	12,000	271,000
Keeyask GS	374,000	90,000	29,000	493,000
Additional DSM	24,000	50,000	1,000	75,000
Pointe du Bois: Spillway	31,000	9,000	(1,000)	39,000
Conawapa: Financing of Sunk Costs	19,000	13,000	-	32,000
Total - Generation	**964,228**	**532,710**	**651,635**	**2,148,572**
Transmission	53,655	41,015	58,893	153,563
Existing US Interconnection	2,498	1,384	945	4,827
MISO Fees	-	-	4,767	4,767
MMTP/GNTL	70,000	27,000	17,000	114,000
Riel 230/500 kV Station	15,000	8,000	-	23,000
Total - Transmission	**141,153**	**77,399**	**81,606**	**300,157**
Subtransmission	20,637	21,623	26,743	69,004
Total - Subtransmission	**20,637**	**21,623**	**26,743**	**69,004**
Distribution Substation	20,967	28,443	42,275	91,685
Distribution Lines	57,348	46,635	44,687	148,670
Distribution Serialized Equipment	10,850	12,943	4,830	28,623
Distribution Services	3,034	2,468	2,364	7,866
Distribution Meter	1,637	4,537	2,562	8,736
Area & Roadway Lighting Dedicated	3,412	4,244	9,193	16,849
Distribution Diesel	56	92	519	667
Total - Distribution Plant	**97,305**	**99,361**	**106,431**	**303,098**
Cust Service - General	2,241	6,021	45,272	53,534
Cust Acct - Billings	1,400	2,819	28,277	32,495
Cust Acct - Collections	920	1,527	18,588	21,035
Marketing - R & D	40	58	808	905
Inspection	179	590	3,620	4,390
Meter Reading	607	950	12,257	13,813
Total - Distribution Services	**5,386**	**11,965**	**108,821**	**126,172**
Total Revenue Requirement	**1,228,710**	**743,058**	**975,236**	**2,947,004**

c) The level of detail requested is not available in the absence of the preparation of a full cost of service study. However, to accommodate the request, the schedules below have been prepared to provide a high level indication of the anticipated shift in functionalized costs. The following assumptions have been made:

- To establish a revenue requirement in the 2018 and 2022 fiscal years, the Projected Operating Statement in IFF15 has been adjusted in Table 3 below as follows:
  - Net Income is added as a cost for purposes of Cost of Service; and
  - Other Revenues are used to reduce Operating Costs, excluding the $87 M related to the amortization of BPIII reserve in 2022;
- In Table 4, the estimated carrying and operating costs of the major new G&T projects as provided in response to PUB/MH-71e are functionalized and added to the PCOSS14-Amended revenue requirement as follows:
  - Keeyask, Pointe du Bois Spillway, Additional DSM and Conawapa: Financing of Sunk Costs have been added to the Generation function
  - MMTP/GNTL has been included in Transmission.
  - Riel 230/500 kV Station has been separated from the combined costs provided for Bipole III & Riel Station in PUB/MH-71e and functionalized as Transmission.
  - All remaining BPIII, including Riel DC Convertor, have been functionalized as Generation. BPIII Interest costs for 2022 are net of the amortization of BPIII reserve.
- Table 4 provides the residual revenue requirement, which was not specifically attributed to a new major G&T project which is assumed related to existing assets. The residual revenue requirement has been functionalized by cost category in PCOSS14-Amended as provided in Table 5.

Table 3:

	IFF		2017/18 COS Revenue Requirement			
General Consumers	2018	Revenue	Interest	Depreciation	Operating	Total
at approved rates	1,553	1,553				-
additional*	125	125				-
BPIII Reserve Account	(69)	(69)				-
Extraprovincial	449	449				-
Other	28				(28)	(28)
Operating and Administrative	557				557	557
Finance Expense	579		579			579
Depreciation and Amortization	450			450		450
Water Rentals and Assessments	113				113	113
Fuel and Power Purchased	182				182	182
Capital and Other Taxes	136		96		39	136
Other Expenses	2				2	2
Corporate Allocation	8		7	2		8
Non-controlling Interest	4		(4)			(4)
Net Income	63		63			63
		2,058	740	452	866	2,058

	IFF		2021/22 COS Revenue Requirment			
General Consumers	2022	Revenue	Interest	Depreciation	Operating	Total
at approved rates	1,570	1,570				-
additional*	411	411				-
BPIII Reserve Account	-	0				-
Extraprovincial	966	966				-
Other	119		(87)		(32)	(119)
Operating and Administrative	607				607	607
Finance Expense	1,188		1,188			1,188
Depreciation and Amortization	742			742		742
Water Rentals and Assessments	127				127	127
Fuel and Power Purchased	228				228	228
Capital and Other Taxes	157		114		43	157
Other Expenses	2				2	2
Corporate Allocation	8		7	1		8
Non-controlling Interest	(1)		1			1
Net Income	6		6			6
		2,947	1,229	743	975	2,947

Table 4:

2017/18 Adjustments to Functionalized Revenue Requirement ($ millions)

	Interest	Depreciation	Operating	Revenue Requirement
IFF15 Revenue Requirement	740	452	866	2,058
less: PCOSS14 Revenue Requirement	(549)	(421)	(783)	(1,753)
Increase in Revenue Requirement	192	31	82	305
less: Revenue Requirement of Major New G&T				
Additional DSM	(9)	(12)	(1)	(22)
Pointe du Bois: Spillway	(33)	(9)	1	(41)
Conawapa: Financing of Sunk Costs	(11)	(8)	-	(19)
Riel 230/500 kV Station	(17)	(8)	-	(25)
Change in Revenue Requirement Excl Major New G&T	122	(6)	82	198

2021/22 Adjustments to Functionalized Revenue Requirement ($ millions)

	Interest	Depreciation	Operating	Revenue Requirement
IFF15 Revenue Requirement	1,229	743	975	2,947
PCOSS14 Revenue Requirement	(549)	(421)	(783)	(1,753)
Increase in Revenue Requirement	680	322	192	1,194
less: Revenue Requirement of Major New G&T				
BP III and Riel Convertor Station	(168)	(91)	(12)	(271)
Keeyask GS	(374)	(90)	(29)	(493)
Additional DSM	(24)	(50)	(1)	(75)
Pointe du Bois: Spillway	(31)	(9)	1	(39)
Conawapa: Financing of Sunk Costs	(19)	(13)	-	(32)
MMTP/GNTL	(70)	(27)	(17)	(114)
Riel 230/500 kV Station	(15)	(8)	-	(23)
Change in Revenue Requirement Excl Major New G&T	(21)	34	134	147

Table 5:

PCOSS14-Amended Functionalized Revenue Requirement Percentages

	Interest	Depreciation	Operating
Existing Generation	52.3%	32.7%	19.6%
Existing HVDC incl Dorsey Convertor Station	5.8%	13.3%	6.4%
AC Collector incl Switching Stations	0.1%	0.2%	0.1%
Coal GS	0.4%	2.1%	2.3%
Natural Gas GS	1.4%	2.3%	1.9%
Diesel GS	0.2%	0.4%	0.9%
Water Rentals	0.0%	0.0%	13.8%
Fuel and Power Purchases	0.0%	0.0%	11.5%
Wind Purchases	0.0%	0.0%	8.3%
NEB	0.0%	0.0%	0.1%
Trading Desk	0.0%	0.3%	1.5%
Uniform Rates	4.3%	0.0%	0.0%
Existing DSM/AEF	1.5%	10.3%	0.1%
Total - Generation	**66.0%**	**61.5%**	**66.6%**
Transmission	10.2%	9.0%	6.4%
Existing US Interconnection	0.5%	0.3%	0.1%
MISO Fees	0.0%	0.0%	0.5%
Total - Transmission	**10.6%**	**9.3%**	**7.0%**
Subtransmission	3.9%	4.8%	2.9%
Total - Subtransmission	**3.9%**	**4.8%**	**2.9%**
Distribution Substation	4.0%	6.3%	4.6%
Distribution Lines	10.9%	10.2%	4.9%
Distribution Serialized Equipment	2.1%	2.8%	0.5%
Distribution Services	0.6%	0.5%	0.3%
Distribution Meter	0.3%	1.0%	0.3%
Area & Roadway Lighting Dedicated	0.6%	0.9%	1.0%
Distribution Diesel	0.0%	0.0%	0.1%
Total - Distribution Plant	**18.4%**	**21.8%**	**11.6%**
Cust Service - General	0.4%	1.3%	4.9%
Cust Acct - Billings	0.3%	0.6%	3.1%
Cust Acct - Collections	0.2%	0.3%	2.0%
Marketing - R & D	0.0%	0.0%	0.1%
Inspection	0.0%	0.1%	0.4%
Meter Reading	0.1%	0.2%	1.3%
Total - Distribution Services	**1.0%**	**2.6%**	**11.9%**
Total Revenue Requirement	**100.0%**	**100.0%**	**100.0%**

Section:	2016/17 Interim Application Attachment 16 MFR 1; 2015/16 GRA Appendix 11.15	**Page No.:**	
Topic:	Cost of Service Study		
Subtopic:	Export and Domestic Revenue		
Issue:			

PREAMBLE TO IR (IF ANY):

QUESTION:

a) Please refile Attachment 16 from the 2016/17 Interim Rate Application splitting firm and opportunity export volumes for each year.

b) Please provide the firm and opportunity export volumes specifically for Keeyask for the years shown in Attachment 16.

c) Please provide total additional revenues from Keeyask for the years shown in Attachment 16.

RATIONALE FOR QUESTION:

To estimate the impacts of the addition of Keeyask on allocations of revenue requirement.

RESPONSE:

a) This Information Request discloses export price forecast and contract information that is commercially sensitive and confidential. Therefore, the response is being filed in confidence under Rule 13 of the Public Utilities Board's Rules of Practice and Procedure. A redacted version has been provided below.

AVERAGE UNIT REVENUE/COST CALCULATION IFF15

	VOLUMES (in GW.h)	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
	Demand:										
A	Manitoba Domestic Energy Sales	22593	23088	22971	22949	22705	23218	23289	23503	23710	23940
B	Domestic energy Losses	3088	3352	3373	3053	2996	3003	2893	2922	2952	2983
C	Firm & Opportunity Export Sales to Canada	471	263	581	603	618	888	993	889	883	870
D	Firm Export Sales to Canada (Lake St Joseph)	49	92	91	91	91	91	91	91	91	91
E	Total Export Sales to Canada (C+D)	520	355	671	694	709	979	1083	980	974	961
F	Total Export Sales to US	8785	6929	6183	6268	6855	9136	9986	9670	9622	9398
G	Net Transmission Losses	928	691	622	838	704	929	1011	987	963	935
	Total Demand Volumes:	35914	34395	33820	33602	33970	37264	38263	38263	38220	38215
H	Total Firm Export Sales	[redacted]									
I	Total Opportunity Export Sales										
	Supply:										
J	MH Hydraulic Generation	34915	31858	31194	31098	31648	34555	35344	35308	35305	35201
K	MH Thermal Generation	58	63	370	348	269	154	158	158	149	158
L	Purchased Energy	941	2474	2258	2157	2033	2555	2762	2796	2767	2857
	Total Supply Volumes:	35914	34395	33820	33602	33970	37264	38263	38263	38220	38215

	REVENUE/COST (in millons of dollars)	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
	Total Manitoba Domestic Energy Sales:										
M	Manitoba Domestic Energy Sales @ Approved Rates	1 517.178	1 555.835	1 552.633	1 552.228	1 541.920	1 568.389	1 570.022	1 582.776	1 595.823	1 610.406
N	Additional Domestic Revenue	-	61.455	125.080	191.300	258.442	334.786	410.833	493.050	579.785	671.805
	Manitoba Domestic Sales	1 517.178	1 617.290	1 677.713	1 743.528	1 800.362	1 901.176	1 980.855	2 075.826	2 175.608	2 282.212
	Extraprovincial Revenue:										
O	Total Export Sales to Canada	18.733	17.032	34.607	37.530	41.104	74.620	85.355	76.668	77.698	78.366
P	Total Export Sales to USA	363.647	378.641	408.628	429.891	500.470	744.390	874.461	895.564	898.276	900.469
Q	Other Non-Energy Related Revenues	8.907	8.281	2.268	2.299	2.327	2.355	2.402	2.449	2.497	2.548
R	Transmission Credits	3.900	4.047	3.909	3.892	3.872	3.850	3.931	4.013	4.097	4.183
	Extraprovincial Revenue	395.188	408.001	449.413	473.611	547.773	825.215	966.148	978.694	982.568	985.566
S	Total Firm Export Sales	[redacted]									
T	Total Opportunity Export Sales										
	Water Rentals & Assessments:										
U	MH Water Rentals	116.712	106.493	104.267	103.947	105.788	115.505	118.141	118.022	118.009	117.662
V	Assessments	6.500	6.745	6.515	6.488	6.453	6.416	6.551	6.689	6.829	6.972
W	Other Costs	2.485	2.309	2.334	2.358	2.381	2.404	2.428	7.233	7.505	7.695
	Water Rentals & Assessments:	125.697	115.548	113.117	112.791	114.620	124.325	127.119	131.943	132.343	132.329
	Fuel & Power Purchased:										
X	MH Thermal Generation	2.821	2.932	25.061	24.114	20.903	12.978	13.993	14.596	14.289	15.778
Y	Purchased Energy	71.738	101.251	117.704	116.340	114.325	135.130	148.387	153.262	155.650	163.065
Z	Other Non-Energy related Costs	4.498	4.707	8.399	8.458	8.248	10.288	18.046	11.451	11.870	14.742
AA	Transmission Charges	41.168	42.292	31.002	30.863	30.706	47.385	47.591	47.808	48.036	48.276
	Fuel & Power Purchased	120.228	151.182	182.166	179.772	174.180	205.781	228.018	227.116	229.644	241.861

AVERAGE UNIT REVENUE/COST ($/MW.h))	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Manitoba Domestic Energy Sales @ Approved Rates (M/A)	$ 67.15	$ 67.44	$ 67.59	$ 67.64	$ 67.91	$ 67.46	$ 67.41	$ 67.34	$ 67.31	$ 67.27
Additional Domestic Revenue (N/A)	-	2.66	5.45	8.34	11.38	14.42	17.64	20.98	24.45	28.08
Total Manitoba Domestic Energy Sales @ meter (M+N)/A	67.15	70.11	73.04	75.97	79.29	81.88	85.06	88.32	91.76	95.33
Total Export Sales to Canada (O/C)	$ 39.74	$ 64.88	$ 59.80	$ 62.25	$ 68.49	$ 84.02	$ 85.99	$ 86.22	$ 87.98	$ 90.07
Total Export Sales to USA* (P+R-AA)/F	37.15	48.84	61.71	64.28	69.09	78.72	83.19	88.29	88.79	91.13
Total Export Sales * (O+P+R-AA)/(C+F)	37.29	49.42	61.53	64.10	68.87	77.36	83.45	88.29	88.72	91.04
Total Domestic & Total Firm Export Sales * (M+N+S+R-AA)/(A+H)	[redacted]									
Total Firm Export Sales (S/H)										
Total Opportunity Export Sales (T/I)										
Total Domestic & Export Sales * (M+N+S+T+R-AA)/(A+H+I)	58.47	65.19	70.42	73.24	76.71	80.52	84.54	87.88	90.83	94.04
MH Hydraulic Generation (Water Rentals) (U/J)	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation (X/K)	$ 48.62	$ 46.65	$ 67.65	$ 69.37	$ 72.26	$ 84.32	$ 88.62	$ 92.33	$ 96.01	$ 99.98
Purchased Energy (including Assessments) (Y+V)/L	$ 63.16	$ 43.66	$ 55.06	$ 56.94	$ 59.41	$ 55.40	$ 56.10	$ 57.20	$ 58.72	$ 59.52

** Includes net transmission charges*

AVERAGE UNIT REVENUE/COST CALCULATION IFF15

	VOLUMES (in GW.h)	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
	Demand:										
A	Manitoba Domestic Energy Sales	24178	24407	24634	24855	25080	25432	25908	26394	26926	27514
B	Domestic energy Losses	3016	3048	3083	3114	3146	3198	3259	3324	3395	3475
C	Firm & Opportunity Export Sales to Canada	902	901	915	906	902	923	914	909	903	901
D	Firm Export Sales to Canada (Lake St Joseph)	91	91	91	91	91	91	91	91	91	91
E	Total Export Sales to Canada (C+D)	993	992	1005	997	993	1013	1005	999	994	992
F	Total Export Sales to US	8835	8635	8389	8221	8031	7533	7010	6533	6109	5997
G	Net Transmission Losses	894	892	855	835	813	774	718	668	622	586
	Total Demand Volumes:	37914	38175	37986	38022	38063	37949	37899	37919	38046	38564
H	Total Firm Export Sales	[redacted]									
I	Total Opportunity Export Sales										
	Supply:										
J	MH Hydraulic Generation	35139	35360	35265	35258	35254	35322	35224	35222	35296	35314
K	MH Thermal Generation	158	159	135	137	139	122	118	114	112	107
L	Purchased Energy	2618	2656	2567	2627	2670	2504	2558	2582	2638	3144
	Total Supply Volumes:	37914	38175	37986	38022	38063	37949	37900	37919	38046	38564

	REVENUE/COST (in millions of dollars)	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
	Total Manitoba Domestic Energy Sales:										
M	Manitoba Domestic Energy Sales @ Approved Rates	1 625.643	1 640.589	1 655.004	1 669.083	1 683.412	1 705.889	1 734.283	1 763.345	1 795.408	1 831.203
N	Additional Domestic Revenue	769.162	871.698	979.485	1 092.743	1 157.835	1 230.864	1 311.079	1 394.977	1 484.657	1 581.166
	Manitoba Domestic Sales	2 394.804	2 512.287	2 634.489	2 761.826	2 841.247	2 936.734	3 045.362	3 158.322	3 280.065	3 412.369
	Extraprovincial Revenue:										
O	Total Export Sales to Canada	82.994	84.839	88.340	89.978	92.021	96.310	98.551	101.052	103.495	105.824
P	Total Export Sales to USA	794.413	810.910	779.616	788.362	794.616	759.342	728.472	698.111	669.874	673.216
Q	Other Non-Energy Related Revenues	2.597	2.648	2.700	2.753	2.807	2.863	2.919	2.977	3.035	3.095
R	Transmission Credits	4.271	4.361	4.453	4.546	4.642	4.739	4.839	4.940	5.044	5.150
	Extraprovincial Revenue	884.275	902.757	875.108	885.639	894.086	863.253	834.781	807.080	781.448	787.285
S	Total Firm Export Sales	[redacted]									
T	Total Opportunity Export Sales										
	Water Rentals & Assessments:										
U	MH Water Rentals	117.455	118.193	117.875	117.853	117.840	118.089	117.739	117.733	117.980	118.039
V	Assessments	7.119	7.268	7.421	7.577	7.736	7.898	8.064	8.234	8.408	8.583
W	Other Costs	7.489	7.633	7.843	8.090	8.402	8.745	9.037	9.370	9.652	9.693
	Water Rentals & Assessments:	132.063	133.095	133.139	133.520	133.977	134.712	134.840	135.337	136.039	136.316
	Fuel & Power Purchased:										
X	MH Thermal Generation	16.476	17.374	15.359	16.400	17.398	16.213	16.252	16.536	16.965	16.851
Y	Purchased Energy	153.321	159.145	158.550	166.084	173.024	166.338	173.905	180.805	189.933	225.390
Z	Other Non-Energy related Costs	12.898	15.468	16.213	16.633	17.059	17.323	17.703	18.109	18.538	18.942
AA	Transmission Charges	48.798	49.061	49.336	49.624	49.924	54.963	55.289	55.628	55.981	56.348
	Fuel & Power Purchased	231.493	241.067	239.459	248.721	257.405	254.837	263.149	271.078	281.418	317.531

AVERAGE UNIT REVENUE/COST ($/MW.h))	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
Manitoba Domestic Energy Sales @ Approved Rates (M/A)	$ 67.24	$ 67.22	$ 67.19	$ 67.15	$ 67.12	$ 67.07	$ 66.94	$ 66.81	$ 66.68	$ 66.56
Additional Domestic Revenue (N/A)	31.82	35.72	39.76	43.96	46.17	48.40	50.61	52.85	55.14	57.47
Total Manitoba Domestic Energy Sales @ meter (M+N)/A	99.06	102.93	106.95	111.12	113.29	115.47	117.54	119.66	121.82	124.02
Total Export Sales to Canada (O/C)	$ 91.98	$ 94.12	$ 98.58	$ 99.30	$ 102.02	$ 104.39	$ 107.85	$ 111.21	$ 114.63	$ 117.40
Total Export Sales to USA* (P+R-AA)/F	84.88	86.72	87.58	90.41	93.30	94.13	96.73	99.10	101.32	103.72
Total Export Sales * (O+P+R-AA)/(C+F)	85.53	87.41	88.47	91.29	94.18	95.25	98.01	100.58	103.03	105.51
Total Domestic & Total Firm Export Sales * (M+N+S+R-AA)/(A+H)	[redacted]									
Total Firm Export Sales (S/H)										
Total Opportunity Export Sales (T/I)										
Total Domestic & Export Sales * (M+N+S+T+R-AA)/(A+H+I)	95.17	98.51	101.88	105.79	108.27	110.43	112.97	115.48	117.94	120.31
MH Hydraulic Generation (Water Rentals) (U/J)	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34	$ 3.34
MH Thermal Generation (X/K)	$ 104.35	$ 109.14	$ 114.00	$ 119.55	$ 125.08	$ 132.40	$ 138.26	$ 144.59	$ 150.86	$ 157.49
Purchased Energy (Including Assessments) (Y+V)/L	$ 61.29	$ 62.85	$ 64.65	$ 66.10	$ 67.70	$ 69.59	$ 71.13	$ 73.21	$ 75.19	$ 74.43

** Includes net transmission charges*

b) As stated in the response to PUB/MH-I-38b, MH cannot quantify dependable energy from Keeyask that is available to serve firm export contracts separate from dependable energy to serve Manitoba domestic customers.

c) This Information Request discloses export price forecast and contract information that is commercially sensitive and confidential. Therefore, the response is being filed in confidence under Rule 13 of the Public Utilities Board's Rules of Practice and Procedure. A redacted version has been provided below.

The estimated Keeyask incremental revenue is calculated consistent with that in the response to PUB/MH-I-38c.

REVENUE/COST (in millions of dollars)	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25
Keeyask Domestic & Firm Export Sales	[redacted]									
Keeyask Opportunity Export Sales										
Keeyask Total Sales	238	259	290	302	318	333	349	362	376	388

REVENUE/COST (in millions of dollars)	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
Keeyask Domestic & Firm Export Sales	[redacted]									
Keeyask Opportunity Export Sales										
Keeyask Total Sales	396	410	426	442	453	465	478	492	504	518

Section:	2016/17 Interim Application Attachment 16 MFR 1; 2015/16 GRA Appendix 11.15	**Page No.:**	
Topic:	Cost of Service Study		
Subtopic:	Export and Domestic Revenue		
Issue:			

PREAMBLE TO IR (IF ANY):

QUESTION:

d) Please estimate the impact on the 2CP allocators when Keeyask is fully in service.

RATIONALE FOR QUESTION:

To estimate the impacts of the addition of Keeyask on allocations of revenue requirement.

RESPONSE:

The domestic classes' share of total 2CP demand is expected to decrease in the first years following Keeyask in-service due to the additional Dependable export volumes. However, the addition of Keeyask will not change the load profile for domestic customers, so no other impacts are expected on the 2CP allocator. The impact of Keeyask on domestic class shares of 2CP will diminish in the years following in-service as domestic loads grow and firm export contracts expire.

Section:	2016/17 Interim Application Attachment 16 MFR 1; 2015/16 GRA Appendix 11.15	**Page No.:**	
Topic:	Cost of Service Study		
Subtopic:	Export and Domestic Revenue		
Issue:			

PREAMBLE TO IR (IF ANY):

QUESTION:

e) Please update the in-service revenue requirements shown in Appendix 11.15 (or confirm that the forecast information is already up to date) from the 2015/16 GRA.

RATIONALE FOR QUESTION:

To estimate the impacts of the addition of Keeyask on allocations of revenue requirement.

RESPONSE:

In past proceedings, the PUB has expressed an interest in understanding the costs related to Major New Generation and Transmission projects. To assist the PUB's understanding, Manitoba Hydro estimated the carrying and operating costs of forecast Major New Generation and Transmission projects in NFAT Exhibit MH-211 and in Appendix 11.15 – Financial Information MFR 9 in the 2014/15 & 2015/16 GRA. The schedule below has been updated for IFF15 Major New Generation & Transmission, as well as DSM and Major and Base Capital Expenditures.

However, the most reliable measure of Manitoba Hydro's revenue requirement is the additional General Consumers indicated on the electric operations projected operating statement (Appendix 1 – Integrated Financial Forecast, pages 41 and 42 from the 2016/17 Supplemental Filing) which is derived based on balancing the costs of the integrated hydro-

electric system, for new asset additions as well as existing assets, with maintaining minimum financial ratios as well as rate stability and affordability for customers.

Costs such as depreciation expense, water rentals, and operating, maintenance and administrative expenses may be directly attributable to a Major New Generation and Transmission asset; however, finance expense, capital taxes and benefits are not. Reliance on the estimated carrying and operating costs in the attached schedule as a representation of revenue requirement must be weighed with the inherent limitations of the analysis, estimation assumptions and methods described below.

1) Manitoba Hydro issues debt based on the consolidated cash requirements of the Corporation and does not assign specific debt issues on a project-by-project basis. As such, finance expense attributable to a specific project is estimated for the purposes of this analysis by applying Manitoba Hydro's average cost of debt to the asset's net book value (projected in-service cost net of accumulated depreciation). Using the net book value as the principal outstanding for debt associated with an asset assumes that annual depreciation expense approximates revenues available to reduce debt over the life of the asset. This estimation method does not consider that extraprovincial revenues partially offset the costs. As a result, the implied impacts to customers for each project may not be representative.

2) Capital taxes are estimated by applying a fixed 0.5% capital tax rate to construction work in progress until the asset is in-service and the net book value thereafter. Similar to finance expense, the use of net book value as paid up capital to estimate capital taxes may result in implied impacts to customers for each project that are not representative.

3) Manitoba Hydro operates the integrated hydro-electric system to optimize the efficient use of water resources and maximize overall Corporate revenues for the benefit of customers. The output of one facility may not be maximized on its own but contributes to the maximization of the system as a whole. The assumption that depreciation expense approximates the revenue attributable to a project may be reasonable for understanding costs but does not reflect the value of a particular asset to the integrated system and should not be used for resource planning purposes.

4) The analysis considers only the prospective costs of asset additions and does not address the ability of revenues at current PUB approved rates to cover ongoing carrying and operating costs of existing assets. Current domestic rates are lower than

what they otherwise would have been due to extraprovincial revenues partially offsetting costs. In years of low water flow or low opportunity export prices, domestic revenues are not sufficient to cover the resulting reduction in extraprovincial revenues.

5) The analysis does not consider contributions to reserves in order to maintain Manitoba Hydro's self-supporting status and affordable, predictable rates for customers.

Thus, the summation of total costs in the attached schedule may not accurately reflect the overall revenue requirement for Manitoba Hydro or how a particular asset contributes to the overall revenue requirement.

If one accepts the estimated carrying and operating costs in the attached schedule with its inherent limitations, cumulative rate increases that would be required to cover the costs of forecast additions in the 10 year forecast period to 2024/25 are up to 63 percentage points higher (105%) compared to the proposed and indicative cumulative rate increases of 42% over the same time period in MH15.

Even if it is assumed that all extraprovincial revenues (net of water rentals and fuel and power purchases) are allocated to offset the prospective costs of additions, the cumulative rate increases that would still be required are up to 25 percentage points higher (67%) compared to the projected 42% cumulative rate increase in MH15 by 2024/25. Annual rate increases are between 4% and 13% in the period 2015/16 to 2021/22 with minimal rate adjustments thereafter.

Whether or not extraprovincial revenues offset the costs, the annual rate increases required in the period to 2021/22 in the attached schedule are considerably higher than the proposed and indicative 3.95% rate increases in MH15. The lower overall revenue requirements in the integrated system analysis shown in additional General Consumers in MH15 compared to this analysis demonstrates that extraprovincial revenues have a key role in offsetting the costs of investments and reducing the compounding effects of the higher carrying costs over time. The annual differences in rate increases compared to MH15's smoothed 3.95% rate increases also show that there is not a direct flow through of costs in each year to customers. Customers benefit directly from Manitoba Hydro's approach in smoothing rate increases while Manitoba Hydro deviates from its financial targets during the capital build-out and then gradually returns to a position of financial strength.

KEEYASK (ISD 2019/20)
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Finance Expense	-	-	-	-	72	244	342	331	323	318	314	309	301	295	287	283	263	254	245	236
OM&A Costs	-	-	-	-	5	14	14	14	15	15	15	15	15	15	15	14	15	15	15	16
Depreciation	-	-	-	-	6	65	90	90	90	90	90	90	90	90	90	90	90	90	90	90
Capital Tax	12	18	24	28	31	31	32	31	31	30	30	29	29	29	28	28	27	27	26	26
Water Rentals	-	-	-	-	2	12	15	15	15	15	15	15	15	15	15	15	15	15	15	14
	12	18	24	28	116	366	493	482	473	468	464	458	450	444	435	430	410	401	391	382

MANITOBA-MINNESOTA TRANSMISSION PROJECT (Formerly Dorsey-U.S. Border New 500 kV Transmission Line)
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Finance Expense	-	-	-	-	-	9	19	18	17	17	17	17	16	16	15	15	14	13	13	12
OM&A Costs	-	-	-	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Depreciation	-	-	-	0	0	5	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Transmission Charges	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capital Tax	0	0	1	1	2	2	2	2	2	2	2	2	2	2	1	1	1	1	1	1
	0	0	1	1	2	16	26	25	25	24	24	24	23	23	23	22	21	21	20	20

GREAT NORTHERN TRANSMISSION LINE
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Finance Expense	-	-	-	-	-	33	46	44	42	40	39	37	35	33	31	30	27	25	23	21
OM&A Costs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization	-	-	-	-	-	16	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Transmission Charges	-	-	-	-	-	17	16	16	16	15	15	15	15	14	14	18	18	17	17	17
Capital Tax	0	0	1	2	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	2
	0	0	1	2	3	69	87	84	81	79	77	75	73	71	68	71	68	66	63	61

WUSKWATIM
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Finance Expense	91	89	85	83	81	81	80	77	75	74	73	71	69	67	65	64	59	57	55	52
OM&A Costs	12	12	12	13	12	12	12	13	13	13	13	14	14	14	12	11	11	11	11	11
Depreciation	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	27	27
Capital Tax	8	8	8	8	8	8	8	7	7	7	7	7	7	7	7	6	6	6	6	6
Water Rentals	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
	142	140	136	135	132	133	132	129	127	126	124	123	121	120	115	113	108	106	104	101

BIPOLE III & RIEL STATION
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Finance Expense	14	28	28	142	256	260	261	252	243	239	234	228	221	215	207	202	187	179	171	163
OM&A Costs	-	-	-	8	12	12	12	13	13	13	13	14	14	14	15	15	15	15	16	16
Depreciation	9	10	10	69	99	99	99	99	99	99	99	99	99	98	98	98	98	98	98	98
Amortization of BPIII Reserve	-	-	-	-	(87)	(87)	(87)	-	-	-	-	-	-	-	-	-	-	-	-	-
Capital Tax	12	19	22	23	23	23	23	23	22	22	21	21	20	20	19	19	18	18	17	17
	35	57	60	242	304	308	309	386	378	372	367	361	354	346	339	334	318	310	301	294

FINANCING IMPACTS OF THE SUNK COSTS RELATING TO CONAWAPA
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Finance Expense	-	-	11	21	20	19	19	18	17	16	15	15	14	13	12	12	10	9	9	8
Amortization	-	-	8	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
	-	-	19	34	33	33	32	31	30	30	29	28	27	27	26	25	24	23	22	21

POINTE DU BOIS SPILLWAY
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Finance Expense	16	32	30	29	29	29	29	27	27	26	26	25	25	24	23	23	21	20	19	19
OM&A Costs	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)
Depreciation	8	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9	9
Capital Tax	3	3	3	3	3	3	3	3	3	2	2	2	2	2	2	2	2	2	2	2
	27	43	41	40	39	39	39	38	37	37	36	35	35	34	33	33	31	30	29	28

DSM
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Finance Expense	2	5	8	12	16	19	22	23	23	23	23	23	23	23	23	24	24	24	25	26
OM&A Costs	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	2	2	2
Amortization	-	6	12	22	31	40	50	59	67	73	80	82	84	83	83	84	85	86	89	94
Capital Tax	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3
	4	13	23	37	50	63	75	86	93	100	107	108	110	110	110	112	112	114	119	124

SUSTAINING CAPITAL
(In Millions of Dollars)

For the year ended March 31	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Finance Expense	20	53	80	104	131	165	192	211	232	255	279	300	319	340	358	379	378	392	404	416
Depreciation	9	29	48	67	86	106	123	138	155	173	192	210	227	244	259	274	290	307	325	345
Capital Tax	5	8	10	13	15	17	20	22	24	26	28	30	32	35	37	39	41	43	45	47
	34	91	139	184	232	288	335	371	410	454	499	541	578	619	654	692	709	742	774	808
Total Incremental Revenue Requirement (without Net Extraprovincial Revenues)	254	361	444	703	911	1 315	1 527	1 631	1 654	1 690	1 728	1 754	1 773	1 793	1 803	1 831	1 800	1 811	1 824	1 840
Annual Rate Increase/(Decrease)	16.74%	5.54%	4.38%	12.98%	9.52%	15.61%	7.25%	2.91%	0.31%	0.64%	0.65%	0.29%	0.10%	0.14%	-0.14%	0.09%	-1.69%	-0.53%	-0.56%	-0.55%
Cumulative Rate Increase	16.74%	23.20%	28.59%	45.28%	59.10%	83.94%	97.28%	103.03%	103.65%	104.96%	106.31%	106.90%	107.10%	107.40%	107.12%	107.31%	103.81%	102.72%	101.59%	100.48%
Net Extraprovincial Revenues	(149)	(139)	(154)	(181)	(259)	(495)	(611)	(620)	(621)	(611)	(521)	(529)	(503)	(503)	(503)	(474)	(437)	(401)	(364)	(333)
Total Incremental Revenue Requirement (with Net Extraprovincial Revenues)	105	222	290	522	652	820	916	1 011	1 034	1 079	1 207	1 225	1 270	1 289	1 301	1 357	1 364	1 411	1 460	1 507
Annual Rate Increase/(Decrease)	6.91%	6.87%	3.87%	12.60%	6.51%	7.04%	3.96%	3.49%	0.54%	1.36%	4.36%	0.23%	1.18%	0.28%	0.01%	1.29%	-0.51%	0.77%	0.73%	0.53%
Cumulative Rate Increase	6.91%	14.25%	18.67%	33.62%	42.31%	52.33%	58.37%	63.88%	64.77%	67.00%	74.27%	74.68%	76.74%	77.24%	77.25%	79.54%	78.62%	80.00%	81.31%	82.27%
IFF15 Annual Rate Increase	0.00%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	3.95%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
IFF15 Cumulative Rate Increase	0.00%	3.95%	8.06%	12.32%	16.76%	21.37%	26.17%	31.15%	36.33%	41.72%	47.31%	53.13%	59.18%	65.47%	68.78%	72.15%	75.60%	79.11%	82.69%	86.35%

Section:	PCOSS14 Amended	**Page No.:**	Page 11
Topic:	Cost of Service Study		
Subtopic:	Distribution Plant – Service Voltage		
Issue:	30% Reduction		

PREAMBLE TO IR (IF ANY):

The customer and demand allocation factors for GSL 0-30 kV used to allocate Distribution Poles and Wires costs have been reduced by 30% to recognize that these customers do not utilize Manitoba Hydro's secondary voltage distribution facilities. PCOSS13 showed 93.3% RCC ratios while PCOSS14 Amended showed 91.3%.

QUESTION:

a) Please provide the rationale supporting the 30% reduction for GSL 0-30kV customer class and the calculations to support this percentage.

b) Please explain why the RCC ratio decreased for the GSL 0-30kV class while the 30% cost reduction has been recognized.

c) Please detail all changes that have impacted the RCC ratio for this customer class from PCOSS13 to PCOSS14 Amended.

RATIONALE FOR QUESTION:

To understand the allocation to the GSL 0-30 kV customer class.

RESPONSE:

a) Please see Manitoba Hydro's response to PUB/MH I-49.

b) The impact of eliminating any allocation of distribution secondary costs to GSL 0-30kV was a 1.8% increase in class RCC ratio, as shown in Schedule B7 of PCOSS13 (PUB MFR 12).

c) The overall decrease in the RCC for this class between PCOSS13 and PCOSS14 relates to cost and load changes, in addition to methodology changes such as the addition of capacity to weighted energy and inclusion of power purchases in the generation pool.

Section:	PCOSS14	**Page No.:**	Pg.48
Topic:	Cost of Service Study		
Subtopic:	2CP & NCP		
Issue:			

PREAMBLE TO IR (IF ANY):

PCOSS14 stated "Due to a correction in the definition of peak hours, load research data used to estimate this average seasonal class demand in PCOSS14 are based on the single year results for 2011/12. Load research data used to estimate non-coincident peaks are based on the eight year average of 2005/06 to 2011/12."

QUESTION:

a) Please explain the correction to the definition of peak hours and why the correction was necessary.

b) Please explain why MH was unable to make the correction for the definition of peak hours to the prior six years of data.

c) Please provide a comparison of the average weightings based on the 2005/06 to 2011/12 period with that represented for one-year weighting used in the PCOSS14(a)

d) Please provide the weightings for 2012/13, 2013/14 and 2014/15 and discuss how it compares with that used in PCOSS14 Amended.

RATIONALE FOR QUESTION:

To understand the implication of using different time periods in determining weightings used for 2CP.

RESPONSE:

a) Please see Manitoba Hydro's response to PUB/MH I-5b for an explanation of the change in the definition of peak hours.

b) It was determined at that time, given the level of effort involved to re-prepare the six years of data, Manitoba Hydro would rely on the amended one year of data and incorporate additional data as it became available.

c) Please see the tables below. As shown in the tables, there can be significant volatility by reflecting one year of data. Please also see the response to PUB/MH I-5.

d) Please see Tables 2 and 4 below.

Table 1: Winter CP LF from Load Research at Gen Peak (excl wind and imports)

Load Research Study	Residential	GS Small Non Demand	GSS Demand	GS Medium	GSL 750-30kV	GS Large 30-100kV	GS Large 30-100 kV Curtailable	GS Large > 100kV	GS Large > 100 kV Curtailable	Export
05/06	84.6%	72.3%	81.3%	82.1%	80.9%	86.8%	111.8%	98.1%	99.1%	94.5%
06/07	68.3%	73.1%	75.9%	76.8%	80.0%	94.5%	101.9%	101.9%	98.6%	78.6%
07/08	78.4%	86.9%	88.3%	92.1%	96.7%	94.0%	97.1%	98.8%	99.9%	83.4%
08/09	77.7%	77.2%	80.5%	82.2%	83.9%	91.1%	92.8%	97.7%	102.6%	88.6%
09/10	66.9%	73.3%	78.6%	80.2%	82.4%	100.2%	97.1%	96.0%	100.6%	109.5%
10/11	76.8%	80.9%	82.6%	84.4%	86.7%	110.0%	95.7%	96.4%	96.4%	111.2%
11/12	71.9%	74.3%	76.5%	79.0%	82.1%	96.0%	103.1%	97.1%	105.2%	115.6%
Average	**74.9%**	**76.9%**	**80.5%**	**82.4%**	**84.7%**	**96.1%**	**99.9%**	**98.0%**	**100.3%**	**97.3%**

Table 2: Winter CP LF from Load Research at Gen Peak (incl wind and imports)

Load Research Study	Residential	GS Small Non Demand	GSS Demand	GS Medium	GSL 750-30kV	GS Large 30-100kV	GS Large 30-100 kV Curtailable	GS Large > 100kV	GS Large > 100 kV Curtailable	Export
11/12*	70.1%	73.9%	76.9%	79.0%	81.6%	92.2%	102.3%	96.9%	105.1%	111.6%
12/13	73.7%	80.4%	82.8%	84.8%	87.1%	98.8%	96.0%	96.9%	99.4%	76.0%
13/14	75.3%	79.5%	80.3%	81.9%	83.9%	97.7%	104.2%	95.6%	102.2%	87.0%
Average	**73.0%**	**77.9%**	**80.0%**	**81.9%**	**84.2%**	**96.2%**	**100.8%**	**96.4%**	**102.2%**	**91.5%**

Table 3: Summer CP LF from Load Research at Gen Peak (excl wind and imports)

Load Research Study	Residential	GS Small Non Demand	GSS Demand	GS Medium	GSL 750-30kV	GS Large 30-100kV	GS Large 30-100 kV Curtailable	GS Large > 100kV	GS Large > 100 kV Curtailable	Export
05/06	88.0%	73.1%	82.6%	81.7%	84.4%	98.8%	98.9%	110.2%	98.3%	89.4%
06/07	75.7%	75.0%	78.5%	79.7%	81.3%	99.2%	99.4%	99.6%	100.7%	81.2%
07/08	78.1%	72.8%	80.9%	80.3%	81.4%	104.6%	114.2%	107.0%	101.6%	86.9%
08/09	82.9%	73.8%	81.1%	79.6%	79.8%	97.8%	96.3%	104.6%	100.4%	83.7%
09/10	83.9%	71.3%	80.6%	78.0%	83.5%	100.4%	93.5%	113.2%	100.7%	86.5%
10/11	88.7%	78.0%	86.4%	85.1%	86.6%	95.9%	100.5%	105.6%	100.5%	77.4%
11/12	77.6%	70.7%	79.2%	78.5%	80.7%	102.1%	95.8%	102.2%	101.6%	89.3%
Average	**82.1%**	**73.5%**	**81.3%**	**80.4%**	**82.5%**	**99.8%**	**99.8%**	**106.1%**	**100.5%**	**84.9%**

Table 4: Summer CP LF from Load Research at Gen Peak (incl wind and imports)

Load Research Study	Residential	GS Small Non Demand	GSS Demand	GS Medium	GSL 750-30kV	GS Large 30-100kV	GS Large 30-100 kV Curtailable	GS Large > 100kV	GS Large > 100 kV Curtailable	Export
11/12*	73.0%	69.7%	78.2%	76.8%	78.8%	105.8%	95.9%	104.8%	104.3%	89.3%
12/13	82.7%	72.5%	80.3%	80.3%	80.3%	102.5%	98.9%	102.4%	96.9%	77.4%
13/14	77.7%	75.6%	81.6%	80.5%	81.4%	93.9%	105.3%	126.9%	98.8%	88.9%
Average	**77.8%**	**72.6%**	**80.0%**	**79.2%**	**80.2%**	**100.7%**	**100.0%**	**111.4%**	**100.0%**	**85.2%**

* PCOSS14-Amended was prepared using the single 2011/12 Load Research study.