REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates; Page No.: 9

PREAMBLE: Manitoba Hydro's corporate standard is to set contingency at a P50 or 50% confidence level.

QUESTION:

Please provide a copy of the corporate policy/standard referenced in the last paragraph

RESPONSE:

In fall 2009, Manitoba Hydro adopted the approach to utilize cost estimates at a P50 confidence level and management reserves to establish cost estimates for major capital projects. This approach was developed as a result of an international review of electric and other industries. The capital cost estimate (including contingency) contains no provision for uncertainty in future construction cost escalation or the potential need for major scope additions resulting from external requirements. The Project Management Reserve could capture these items and they would be added to the estimate. The need for, and quantum of the Project Management Reserve is determined by Manitoba Hydro senior executive.

REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates; Page No.: 10

PREAMBLE: The Appendix states the "inclusion of a P50 level addresses the majority of uncertainty associated with the Point estimate". (emphasis added)

QUESTION:

Please explain why a P50 estimate is considered to reflect the majority of the uncertainty. Doesn't it really just reflect about one half of the uncertainty?

RESPONSE:

A P50 estimate is considered the most likely Base Estimate amount. Statistically, the P50 contingency has the highest likelihood (or frequency) of occurrence compared to other amounts. It includes all identified risk items, assessed at their most likely impact levels (vs. assessing them at their extreme low/high amounts).

Recognizing that the P50 value has an equal chance of underrun or overrun, both scenario analysis and management reserves are examined to determine the recommended project budget.

REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates; Page No.: 11

QUESTION:

What is the "P" values used by other Canadian utilities with hydro-electric facilities (e.g., BC Hydro) as the basis for establishing the contingency amounts to be used in capital budgeting?

RESPONSE:

Similar to Manitoba Hydro, BC Hydro and Hydro Quebec undertake risk analysis of capital cost estimates using industry best practices that provide probabilistic estimate outputs.

BC Hydro uses P50 for establishing the contingency amounts for capital projects and refers to it as “Expected Cost Estimate”. BC Hydro also uses the difference between the P90 and P50 to calculate a component of the “Project Reserve” for budget authorizing purposes.

Hydro Quebec uses P50 for establishing the contingency amount for new projects and P70 for rehabilitation projects.

REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates; Page No.: 27

QUESTION:

Please confirm that the $4.1 Total Base Dollar cost for Keeyask is expressed in 2012 dollars. If not, in what year's dollars are the "Total Base Dollars" for Keeyask expressed?

RESPONSE:

Yes, 2012$.

REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates; Page No.: 27

QUESTION:

Please reconcile the Base Dollar cost of $4.1 B shown in Table 3 with the $3.3 B cost($2014) for Keeyask reported in Appendix 9.3, Table 001 (Note: the $3.3 B was derived based on the sum of total dollar costs shown for Keeyask).

RESPONSE:

The capital cost estimate of $4.1 B (2012 constant dollars) provided in Table 3 of Appendix 2.4 is the total base dollar cost estimate for Keeyask which was assumed in IFF12 and includes the costs associated with the Keeyask Infrastructure Project (KIP) and the Keeyask Generating Station. The $4.1 B excludes costs spent to March 31, 2012.

The capital cost estimate of $3.3 B (2014 constant dollars) provided in Table 001 of Appendix 9.3 is a base dollar cost estimate for the Keeyask Generating Station only, excluding incurred or estimated costs to June 2014. The NFAT economic analysis did not consider capital cost estimates associated with KIP as they are considered sunk costs and common to all development plans.

The following table and points describe the differences in the base dollar capital cost estimate for Keeyask between what was provided in Table 3 of Appendix 2.4 and what was provided in Table 001 of Appendix 9.3.

1 **Comparison of IFF12 and Reference Capital Cost Estimates for Keeyask**

	Table 3, Appendix 2.4	Table 001, Appendix 9.3 Economic Summary Table (Ref-Ref-Ref)	Table 001, Appendix 9.3
	(2012 dollars)	(2014 dollars)	(2012 dollars)
Purpose of Estimate	Capital cost estimate used in the Integrated Financial Forecast IFF12	Reference capital cost estimate used in the NFAT economic analysis	De-escalated to 2012 dollars to be able to compare to Table 3 estimates
Point Estimate Keeyask Infrastructure Project (KIP)	$0.29 B	$0.30 B	$0.29 B
Point Estimate for Keeyask Generating Station	$2.76 B	$2.86 B	$2.76 B
Contingency*	$0.53 B	$0.55 B	$0.53 B
Management Reserve			
• Labour Reserve	$0.38 B	-	-
• Escalation Reserve**	$0.12 B	$0.11 B	$0.10 B
Sunk Costs from March 31, 2012 to June 30, 2014		-$0.59 B	-$0.57 B
TOTAL BASE DOLLAR COST	**$4.1 B**	**$3.3 B**	**$3.1 B**

* Reference capital cost estimate for Keeyask is based on a P50 Contingency

2 ** Reference capital cost estimate for Keeyask is based on 0.6%/yr real escalation

3

4 **Table 3, Appendix 2.4 – $4.1 B**

5 - Capital cost estimate for Keeyask from the Integrated Financial Forecast IFF12

6 - Base dollar estimate in 2012 dollars

- Includes capital costs for Keeyask Infrastructure Project (KIP) and Keeyask Generating Station
- Includes project Contingency to bring the estimate to a P50 confidence level
- Includes Management Reserve – labour reserve and escalation reserve
- Excludes costs spent to March 31, 2012

Table 001, Appendix 9.3 – $3.3 B

- Capital cost estimate for the reference scenario used for NFAT economics
- Base dollar estimate in 2014 dollars
- Includes capital costs for Keeyask Generating Station only
- Includes project Contingency to bring the estimate to a P50 confidence level
- Includes Management Reserve – escalation reserve only
- All incurred or estimated costs to June 2014 are excluded as they are assumed to be sunk

REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates; Page No.: 12

QUESTION:

Please provide a copy of the corporate policy G911 referenced in the last paragraph

RESPONSE:

The fall 2012 forecast of Manitoba Hydro's interest and escalation rates is provided in Appendix 11.2.

REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates; Page No.: 21

QUESTION:

If the standard year over year escalation rate for costs associated with hydro projects is 2.5% (as opposed to a lower value for CPI) why isn't the 2.5% used to escalate the total Base Dollars cost (per Table 3) as opposed to CPI?

RESPONSE:

In Table 3 of Appendix 2.4, real escalation of 0.6% (2.5% minus 1.9% CPI) is used to calculate the escalation reserve from the base dollar estimate and is included in the “2012 Base Estimate”. The real escalation is captured in the Base Estimate because it is a management reserve item. Escalation at CPI (1.9%) is calculated to convert the base dollar estimate to nominal dollars and is included in the “In-Service Cost”.

REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates; Page No.: 36

QUESTION:

Please provide a schedule that sets out the derivation of the $0.12 B Escalation Reserve for Keeyask

RESPONSE:

The Keeyask escalation reserve was calculated based on multiplying 0.6% to all years of the base cash flow. The table below illustrates how the escalation reserve was derived.

Keeyask Escalation of 0.6% in Millions of $2012		
CY/FY	**Total Unadjusted Base Cash Flow ($M)**	**Real Esc - Calculated 0.6%**
2012/13	500.636	
2013/14	158.244	0.95
2014/15	267.913	3.23
2015/16	290.664	5.26
2016/17	458.446	11.10
2017/18	603.497	18.32
2018/19	727.11	26.57
2019/20	509.694	21.80
2020/21	362.412	17.77
2021/22	147.121	8.14
2022/23	50.753	3.13
	$4,076	$116

REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates Page No.: 36

QUESTION:

Please provide a schedule that sets out the derivation of the $0.38 Labour Reserve for Keeyask.

RESPONSE:

Labour reserve for Keeyask was established from:

- Increase to direct and indirect labour costs due to lower than estimated Concrete Productivity;
- Schedule - Cumulative Effects of Construction Delays on Critical Path; and
- Additional costs to work 7 days/week, 12 hour shifts on the General Civil Contract.

The specific values attributed to each cost are commercially sensitive and as such Manitoba Hydro is not able to provide separate amounts for each item.

REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates; Page No.: 36

QUESTION:

Please explain the $0.2 B for "Interest on MH Equity" included in the capital cost for Keeyask.

RESPONSE:

Twenty-five percent of the capital cost of the Keeyask generating station is forecast to be financed through equity by the partners. The $0.2 billion for “Interest on MH Equity” included in the capital cost for Keeyask represents the interest capitalized during construction on Manitoba Hydro’s share of the total equity investment in the Keeyask partnership.

REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates; Page No.: 36

QUESTION:

Why is there no "Interest on MH Equity" cost associated with Conawapa?

RESPONSE:

It is not anticipated that there will be an equity ownership arrangement associated with Conawapa; as such, the $2.59 billion for “Capitalized Interest” represents the interest capitalized during construction on one hundred percent of the capital cost of the Conawapa generating station.

REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates; Page No.: 36

PREAMBLE: At the Technical Conference on September 6, 2013 the presentation on Capital Cost Estimates (slide 26) included Total Base Dollar costs for Keeyask of $3.7 B for the Reference Case

QUESTION:

Please provide a schedule that reconciles the $3.7 B with the $4.1 B value set out in Table 3

RESPONSE:

The table and notes below reconcile the base dollar capital cost estimate for Keeyask between what was provided in Table 3 of Appendix 2.4 and what was provided in slide 26 of the presentation on Capital Cost Estimates at the September 6, 2013 Technical Conference.

	Table 3 **Appendix 2.4**	**Slide 26** **September 6, 2013** **Technical Conference**
Purpose of Estimate	Capital cost estimate used in the Integrated Financial Forecast IFF12	Reference base dollar capital cost estimate used in NFAT financial analysis
Point Estimate for KIP and Keeyask G.S. excluding dollars spent as of March 31, 2012	$3.05 B	$3.05 B
Contingency	$0.53 B	$0.53 B
Management Reserve • Labour Reserve • Escalation Reserve	 $0.38 B $0.12 B	 - $0.10 B
TOTAL BASE DOLLAR COST **(2012 Base Dollars)**	**$4.1 B**	**$3.7 B**

Table 3, Appendix 2.4 – $4.1 B

- Capital cost estimate for Keeyask from the Integrated Financial Forecast IFF12
- Base dollar estimate in 2012 dollars
- Includes capital costs for Keeyask Infrastructure Project (KIP) and Keeyask Generating Station
- Includes project Contingency to bring the estimate to a P50 confidence level
- Includes Management Reserve – labour and escalation
- The escalation reserve is applied to all capital costs including the labour reserve
- Excludes dollars spent to March 31, 2012

Slide 26 from Capital Cost Estimates presentation at the Sept. 6 Technical Conference – $3.7 B

- Capital cost estimate for the reference scenario used for the NFAT financial analysis
- Base dollar estimate in 2012 dollars
- Includes capital costs for Keeyask Infrastructure Project (KIP) and Keeyask Generating Station
- Includes project Contingency to bring the estimate to a P50 confidence level
- Includes Management Reserve – escalation only
- Labour reserve is not included, therefore the escalation reserve applied to capital costs is less than if it was included
- Excludes dollars spent to March 31, 2012

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 3; Page No.: 111

PREAMBLE: At the Technical Conference on September 6, 2013 the presentation on Capital Cost Estimates (slide 26) included a High Total Base Dollar costs for Keeyask of $4.1 B respectively.

QUESTION:

Please provide a schedule that reconciles the High value of $4.1 B with the high capital cost value for Keeyask reported in Appendix 9.3 Table 016 ($3.7 B). (Note: the $3.7 B was derived based on the sum of total dollar costs shown for Keeyask).

RESPONSE:

The high capital cost estimate of $4.1 B (2012 constant dollars) provided in slide 26 (from the presentation on Capital Cost Estimates at the September 6, 2013 Technical Conference) is the total base dollar high cost estimate for the Keeyask G.S. and the Keeyask Infrastructure Project (KIP) excluding actual dollars spent to March 31, 2012.

The high capital cost estimate of $3.7 B (2014 constant dollars) provided in Table 016 of Appendix 9.3 is a base dollar high capital cost estimate for the Keeyask Generating Station only, excluding incurred or estimated costs to June 2014 (sunk costs). The NFAT economics evaluations did not consider capital cost estimates associated with KIP as they are considered sunk costs and common to all development plans.

The table and notes below reconcile the high base dollar capital cost estimate for Keeyask between what was provided in slide 26 of the presentation on Capital Cost Estimates at the September 6, 2013 Technical Conference and Table 016 of Appendix 9.3.

Comparison of High Capital Cost Estimates for Keeyask

	Slide 26 Sept. 6, 2013 Tech. Conf.	Table 016, Appendix 9.3	Table 016, Appendix 9.3
	High Capital Cost (2012 dollars)	Economic Summary Table (Ref-Ref-High) (2014 dollars)	(2012 dollars)
Purpose of Estimate	High capital cost estimate from Slide 26	High capital cost estimate used in the NFAT economic analysis	De-escalated to 2012 dollars to compare to Slide 26 estimates
Point Estimate Keeyask Infrastructure Project (KIP)	$0.29 B	$0.30 B	$0.29 B
Point Estimate for Keeyask Generating Station	$2.76 B	$2.86 B	$2.76 B
Contingency*	$0.53 B	$0.55 B	$0.53 B
Management Reserve			
• Labour Reserve	$0.38 B	$0.40 B	$0.38 B
• Escalation Reserve**	$0.15 B	$0.15 B	$0.15 B
Sunk Costs from March 31, 2012 to June 30, 2014		-$0.54 B	-$0.52 B
TOTAL BASE DOLLAR COST	**$4.1 B**	**$3.7 B**	**$3.6 B**

* High capital cost estimate for Keeyask is based on a P50 Contingency

** High capital cost estimate for Keeyask is based on 0.8%/yr real escalation

Slide 26 from Capital Cost Estimates presentation at the Sept. 6 Technical Conference – $4.1 B

- Base dollar estimate in 2012 dollars
- Includes capital costs for Keeyask Infrastructure Project (KIP) and Keeyask Generating Station
- Includes project Contingency to bring the estimate to a P50 confidence level

- Includes Management Reserve – labour reserve and escalation reserve
- Excludes costs spent to March 31, 2012

Table 016, Appendix 9.3 – $3.7 B

- Base dollar estimate in 2014 dollars
- Includes capital costs for Keeyask Generating Station only
- Includes project Contingency to bring the estimate to a P50 confidence level
- Includes Management Reserve – labour reserve and escalation reserve
- All incurred or estimated costs to June 2014 are excluded as they are assumed to be sunk

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 3; Page No.: 121

PREAMBLE: At the Technical Conference on September 6, 2013 the presentation on Capital Cost Estimates (slide 26) included Low Total Base Dollar costs for Keeyask of $3.4 B.

QUESTION:

Please provide a schedule that reconciles the Low value of $3.4 B with the low capital cost value for Keeyask reported in Appendix 9.3 Table 031 ($3.0 B). (Note: the $3.0 B was derived based on the sum of total dollar costs shown for Keeyask).

RESPONSE:

The low capital cost estimate of $3.4 B (2012 constant dollars) provided in slide 26 (from the presentation on Capital Cost Estimates at the September 6, 2013 Technical Conference) is the total base dollar low cost estimate for the Keeyask G.S. and the Keeyask Infrastructure Project (KIP) excluding actual dollars spent to March 31, 2012.

The low capital cost estimate of $3.0 B (2014 constant dollars) provided in Table 031 of Appendix 9.3 is a base dollar low capital cost estimate for the Keeyask Generating Station only, excluding incurred or estimated costs to June 2014 (sunk costs). The NFAT economic analysis did not consider capital cost estimates associated with KIP as they are considered sunk costs and common to all development plans.

The table and notes below reconcile the low base dollar capital cost estimate for Keeyask between what was provided in slide 26 of the presentation on Capital Cost Estimates at the September 6, 2013 Technical Conference and Table 031 of Appendix 9.3.

Comparison of Low Capital Cost Estimates for Keeyask

	Slide 26 Sept. 6, 2013 Tech. Conf.	Table 031, Appendix 9.3	Table 031, Appendix 9.3
	Low Capital Cost (2012 dollars)	Economic Summary Table (Ref-Ref-Low) (2014 dollars)	(2012 dollars)
Purpose of Estimate	Low capital cost estimate from Slide 26	Low capital cost estimate used in the NFAT economic analysis	De-escalated to 2012 dollars to compare to Slide 26 estimates
Point Estimate Keeyask Infrastructure Project (KIP)	$0.29 B	$0.30 B	$0.29 B
Point Estimate for Keeyask Generating Station	$2.76 B	$2.86 B	$2.76 B
Contingency*	$0.30 B	$0.31 B	$0.30 B
Management Reserve			
• Labour Reserve	-	-	-
• Escalation Reserve**	$0.05 B	$0.05 B	$0.05 B
Sunk Costs from March 31, 2012 to June 30, 2014		-$0.52 B	-$0.50 B
TOTAL BASE DOLLAR COST	**$3.4 B**	**$3.0 B**	**$2.9 B**

* Low capital cost estimate for Keeyask is based on a P10 Contingency

** Low capital cost estimate for Keeyask is based on 0.3%/yr real escalation

Slide 26 from Capital Cost Estimates presentation at the Sept. 6 Technical Conference – $3.4 B

- Base dollar estimate in 2012 dollars
- Includes capital costs for Keeyask Infrastructure Project (KIP) and Keeyask Generating Station
- Includes project Contingency to bring the estimate to a P10 confidence level

- Includes Management Reserve – escalation reserve only
- Excludes costs spent to March 31, 2012

Table 031, Appendix 9.3 – $3.0 B

- Base dollar estimate in 2014 dollars
- Includes capital costs for Keeyask Generating Station only
- Includes project Contingency to bring the estimate to a P10 confidence level
- Includes Management Reserve – escalation reserve only
- All incurred or estimated costs to June 2014 are excluded as they are assumed to be sunk

REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates; Page No.: 15

PREAMBLE: The Appendix states that "a number of contracts on Keeyask have been awarded"

QUESTION:

What percentage of the $3.05 B Point Estimate cost for Keeyask is covered by contracts that have already been awarded?

RESPONSE:

As of September, 2013, 29% of the $3.05 B Point Estimate has been covered by contracts that have already been awarded.

REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates; Page No.: 15

QUESTION:

What percentage of the remaining portion of the $3.05 B Point Estimate cost for Keeyask consists of work that will be competitively tendered?

RESPONSE:

As of September 2013, approximately 55% of the $3.05 B Point Estimate remains to be competitively tendered.

REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates; Page No.: 27

QUESTION:

Please reconcile the Base Dollar cost of $6.1 B shown in Table 3 with the $5.7 B cost($2014) for Conawapa reported in Appendix 9.3, Table 001. (Note: the $5.7 B was derived based on the sum of total dollar costs shown for Conawapa).

RESPONSE:

The capital cost estimate of $6.1 B (2012 constant dollars) provided in Table 3 of Appendix 2.4 is the total base dollar cost estimate for Conawapa which was assumed in IFF12 for the Conawapa Generating Station. The $6.1 B excludes costs spent to March 31, 2012.

The capital cost estimate of $5.7 B (2014 constant dollars) provided in Table 001 of Appendix 9.3 is a base dollar cost estimate for the Conawapa Generating Station, excluding incurred or estimated costs to June 2014.

The following table and points describe the differences in the base dollar capital cost estimate for Conawapa between what was provided in Table 3 of Appendix 2.4 and what was provided in Table 001 of Appendix 9.3.

Comparison of IFF12 and Reference Capital Cost Estimates for Conawapa

	Table 3 Appendix 2.4 (2012 dollars)	Table 001, Appendix 9.3 Economic Summary Table (Ref-Ref-Ref) (2014 dollars)	Table 001, Appendix 9.3 (2012 dollars)
Purpose of Estimate	Capital cost estimate used in the Integrated Financial Forecast IFF12.	Reference capital cost estimate used in the NFAT economic analysis	De-escalated to 2012 dollars to compare to Slide 26 estimates
Point Estimate for Conawapa Generating Station	$4.53 B	$4.70 B	$4.53 B
Contingency*	$0.75 B	$0.78 B	$0.75 B
Management Reserve			
• Labour Reserve	$0.51 B	-	-
• Escalation Reserve**	$0.34 B	$0.32 B	$0.31 B
Sunk Costs from March 31, 2012 to June 30, 2014	-	-$0.11 B	-$0.10 B
TOTAL BASE DOLLAR COST	**$6.1 B**	**$5.7 B**	**$5.5 B**

* Reference capital cost estimate for Conawapa is based on a P50 Contingency.

** Reference capital cost estimate for Conawapa is based on 0.6%/yr real escalation.

Table 3, Appendix 2.4 – $6.1 B

- Capital cost estimate for Conawapa G.S. from the Integrated Financial Forecast IFF12
- Base dollar estimate in 2012 dollars
- Includes capital costs for Conawapa Generating Station
- Includes project Contingency to bring the estimate to a P50 confidence level
- Includes Management Reserve – labour reserve and escalation reserve
- Excludes costs spent to March 31, 2012

Table 001, Appendix 9.3 – $5.7 B

- Capital cost estimate for the reference scenario used for NFAT economics
- Base dollar estimate in 2014 dollars
- Includes capital costs for Conawapa Generating Station
- Includes project Contingency to bring the estimate to a P50 confidence level
- Includes Management Reserve – escalation reserve only
- All incurred or estimated costs to June 2014 are excluded as they are assumed to be sunk

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.3; Page No.: 53

QUESTION:

Please explain why all of Conawapa's power cannot be transmitted from northern Manitoba to southern customers on Manitoba Hydro's HVDC transmission system.

RESPONSE:

Power from the Keeyask and Conawapa generating stations can be transmitted from northern Manitoba to southern customers on Manitoba Hydro's HVDC transmission system when all equipment is in service after the proposed upgrades of the HVdc system. However, in order to provide firm transmission, a reliable transmission path is required with the largest single piece of equipment out of service.

When the firm capability of the HVDC system (including spare transmission capacity to provide for reliable transmission capability) is compared to the total capability of the generating stations on the HVDC system, there is a shortfall of approximately 300MW. The 300MW shortfall would only occur in those development plans where both the Keeyask and Conawapa generating stations are developed. The proposed transmission solution for this shortfall is the north-south upgrades.

In order to manage the maximum loading on the HVdc system with both Keeyask and Conawapa generating stations in service, the proposed solution divides the HVdc system into two separate systems, with Bipole I on one system and Bipoles II and III on the other. This division also requires that northern generation be separated to two parts such that the transmission capacity of HVdc is matched with the generation on each part in the best possible

manner. Therefore, Bipole I will have both Kettle and Keeyask generation dedicated to it, while Bipoles II and III will be connected to Long Spruce, Limestone, and Conawapa.

On the system with Bipoles II and III, Bipole II has a capability of 2000 MW, and Bipole III has a capability of 2300 MW (2000 MW with 15% continuous overload capability), for a combined capability of 4300 MW of transmission. The generation consists of Long Spruce, Limestone and Conawapa generating stations for a total simultaneous maximum generation capability of 3725 MW. Considering the HVdc system consisting of Bipole II and III, which has 4 valve groups on each bipole, the largest valve group is that of Bipole III at 575 MW. If one valve group is assumed out of service, the firm transmission on this part of the system is 3725 MW and is adequate to carry the total generation of Long Spruce, Limestone and Conawapa.

The system with Bipole I has transmission capability of 1854 MW. Bipole I system rated at 1854 MW, with six valve groups, each of 309 MW, only has a firm transmission capacity of 1545MW, considering a valve group outage. The combined generation capacity of Keeyask (630 MW net addition) and Kettle (1224 MW) is 1854 MW. A north-south ac transmission development of up to 300 MW is required to allow for the outage of a Bipole I valve group.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.3; Page No.: 53

QUESTION:

What portion of Conawapa's power (dependable and total available) cannot be transmitted south on the HVDC system (including Bipole III)?

RESPONSE:

See response to CAC/MH I-014a.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 3; Page No.: 91

QUESTION:

With respect to Table 001 please breakdown the Transmission column of costs between those applicable to Keeyask vs. Conawapa vs. North-South Transmission.

RESPONSE:

Please see the table below for a breakdown of the Transmission column from Appendix 9.3, Table 001, page 91, between Keeyask GOT, Conawapa GOT, and North-South Transmission.

Transmission

Energy Price	**Reference**
Discount Rate	**Reference**
Capital Cost	**Reference**

	Capital Costs (Millions of 2014$)		
	Transmission		
FYB	Keeyask GOT	Conawapa GOT	North-South Transmission
2012	0.00	0.00	0.00
2013	0.00	0.00	0.00
2014	11.14	0.00	0.00
2015	9.05	0.00	0.00
2016	16.02	0.00	0.00
2017	28.02	0.00	0.00
2018	39.82	0.00	0.00
2019	47.18	0.00	3.53
2020	0.01	0.00	3.53
2021	0.00	0.54	42.37
2022	0.00	1.07	21.18
2023	0.00	2.14	35.31
2024	0.00	4.82	60.02
2025	0.00	2.14	84.74
2026	0.00	0.00	102.39
2027	0.00	0.00	0.00
2028	0.00	0.00	0.00
2029	0.00	0.00	0.00
2030	0.00	0.00	0.00
2031	0.00	0.00	0.00
2032	0.00	0.00	0.00
2033	0.00	0.00	0.00
2034	0.00	0.00	0.00
2035	0.00	0.00	0.00
2036	0.00	0.00	0.00
2037	0.00	0.00	0.00
2038	0.00	0.00	0.00
2039	0.00	0.00	0.00
2040	0.00	0.00	0.00
2041	0.00	0.00	0.00
2042	0.00	0.00	0.00
2043	0.00	0.00	0.00
2044	0.00	0.00	0.00
2045	0.00	0.00	0.00
2046	0.00	0.00	0.00
2047	0.00	0.00	0.00
2048	0.00	0.00	0.00
2049	0.73	0.00	0.00
2050	0.41	0.00	0.00
2051	14.98	0.00	0.00
2052	19.00	0.00	0.00

(Table continued on next page)

	Capital Costs (Millions of 2014$)		
	Transmission		
FYB	Keeyask GOT	Conawapa GOT	North-South Transmission
(Table continued from previous page)			
2053	20.54	0.00	0.00
2054	16.76	0.00	0.87
2055	0.00	0.00	0.87
2056	0.00	0.00	10.47
2057	0.00	0.00	5.23
2058	0.00	0.00	8.72
2059	0.00	0.00	14.83
2060	0.00	0.00	20.93
2061	0.00	0.00	25.29
2062	0.00	0.00	0.00
2063	0.00	0.00	0.00
2064	10.42	0.00	0.00
2065	8.65	0.00	0.00
2066	1.04	0.00	0.00
2067	9.01	0.00	0.00
2068	19.28	0.00	0.00
2069	30.42	0.00	2.66
2070	0.01	0.00	2.66
2071	0.00	0.54	31.90
2072	0.00	1.07	15.95
2073	0.00	2.14	26.59
2074	0.00	4.82	45.19
2075	0.00	2.14	63.80
2076	0.00	0.00	77.10
2077	0.00	0.00	0.00
2078	0.00	0.00	0.00
2079	0.00	0.00	0.00
2080	0.00	0.00	0.00
2081	0.00	0.00	0.00
2082	0.00	0.00	0.00
2083	0.00	0.00	0.00
2084	0.73	0.00	0.00
2085	0.41	0.00	0.00
2086	14.98	0.00	0.00
2087	19.00	0.00	0.00
2088	20.54	0.00	0.00
2089	16.76	0.00	0.00
2090	0.00	0.00	0.00
Salvage Value	2.88	0.18	5.17
PV @ 5.05%	143.69	7.05	233.08

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.3.5; Page No.: 55

QUESTION:

Is the $498 M capital cost for North-South Transmission referenced on page 55 the full in-service cost?

RESPONSE:

The $498 M capital cost for the North-South Transmission referenced on page 55 is the full in-service cost.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.3.5; Page No.: 55

QUESTION:

Please reconcile this $498 M value with the $395.6 M value reported in Appendix A (IFF12), page 29.

RESPONSE:

The $395.6 M reported in the IFF12 cost is a high level planning estimate. The base cost of $300 M occurs in the in-service year, and does not fully consider contingency.

The $498 M included in the NFAT is a more detailed estimate. The base cost of $340 M is distributed over seven years, and considers contingency. Aside from the increase in the total base cost, this cash flow incurs a higher interest expense due to distribution of the cash flow.

The following table illustrates the application of interest and escalation to each of these base costs to determine the in-service costs.

Fiscal Yr Ending	North-South Transmission		Interest	Escalation	Total In -Service Cost
	Appendix 9.3, Table 001 (2014$)	Base Estimate (2012$)			
2020	3.5	3.4	0.1	0.5	
2021	3.5	3.4	0.4	0.6	
2022	42.4	40.8	1.9	8.1	
2023	21.2	20.4	4.3	4.5	
2024	35.3	34.0	6.6	8.3	
2025	60.0	57.8	10.4	15.5	
2026	84.7	81.6	16.6	23.8	
2027	102.4	98.6	24.7	31.2	497.6
Grand Total	353.1	340.0	65.0	92.6	497.6

IFF12	300.00	1.80	93.80	395.60
Difference	40.00	63.21	(1.18)	102.03

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.3.5; Page No.: 55

QUESTION:

Please reconcile this $498 M value with the value (prior to discounting) included in Appendix 9.3, Table 001 (page 91).

RESPONSE:

Once interest and escalation is added to the base estimate, the in-service cost becomes $498 M as shown in the table below.

Fiscal Yr Ending	North-South Transmission		Interest	Escalation	Total In -Service Cost
	Appendix 9.3, Table 001 (2014$)	Base Estimate (2012$)			
2020	3.5	3.4	0.1	0.5	
2021	3.5	3.4	0.4	0.6	
2022	42.4	40.8	1.9	8.1	
2023	21.2	20.4	4.3	4.5	
2024	35.3	34.0	6.6	8.3	
2025	60.0	57.8	10.4	15.5	
2026	84.7	81.6	16.6	23.8	
2027	102.4	98.6	24.7	31.2	497.6
Grand Total	353.1	340.0	65.0	92.6	497.6

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.4.5; Page No.: 58

QUESTION:

Is the $350 M capital cost for Manitoba portion of the Manitoba-Minnesota Transmission referenced on page 58 the full in-service cost?

RESPONSE:

The $350 M capital cost for the Manitoba portion of the Manitoba-Minnesota Transmission referenced on page 58 is the full in-service cost.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.4.5; Page No.: 58

QUESTION:

Please reconcile this $350 M value with the $204.8 M value reported in Appendix A (IFF12), page 29.

RESPONSE:

The cost of the Manitoba portion of the 750MW interconnection to the US has increased from $205 million in IFF12 to $331 million in the NFAT financial analysis. The $126 million increase is due to an increase of 110 km in the transmission line length.

The $350 million in-service cost referenced in Section: 2.4.5, Page No.: 58 reflects an additional $19 million increase related to an expansion to the Glenboro station compared to project cost in the NFAT analysis. This expansion was not known at the time of preparation of the NFAT analysis.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 3; Page No.: 91

QUESTION:

With respect to Table 001 please breakdown the Transmission-U.S. T/L column of costs as between those applicable to the Manitoba portion of the line vs. the US portion of the line.

RESPONSE:

With respect to the 750 MW US interconnection, Manitoba Hydro stated in Chapter 8 Page 7 that "Manitoba Hydro will only enter an arrangement where it will not own more than 49% of the interconnection facilities in the US". At the time of the submission of the NFAT Business Case, assumptions were made regarding a combined amount of capital and operating costs associated with the US portion of 750 MW US interconnection for which Manitoba Hydro would be responsible. For purposes of the NFAT evaluation, assumptions were made on the proportion of costs that would be attributed to capital and operating. Since the filing of the NFAT Business Case negotiations regarding the US interconnection have progressed and will likely result in an arrangement different than that assumed in the NFAT Business Case. Manitoba Hydro will disclose new assumptions related to the US interconnection when they become available.

Appendix 9.3, Table 001 reflects the 2012 planning assumptions for capital and related costs and net average flow related revenue used in the NFAT Business Case. It should be noted that the initial investment in the interconnection facilities ends in 2020. The values in subsequent years represent the capital cost of replacing aging assets for the Manitoba portion of the US interconnection over the study life.

The cost referred to includes 100% of the Manitoba portion and 40% of the US portion. For the US portion, in order to model the financials, 18% of the capital was assumed to be funded directly during construction, and 22% was assumed to be funded during operation (both were included in analysis). The aggregate of the construction and operation period costs is 40% of the total project capital and maintenance cost. This is consistent with arrangements that were being discussed when the models were developed.

In Table 001, the capital cost assumption for the initial investment for the Manitoba portion of the 750 MW US Interconnection is $277 M (2014$ base cost). For evaluation purposes, the capital cost assumption for the initial investment for the US portion of the 750 MW US Interconnection, for which Manitoba Hydro is assumed to be responsible, is $122 M (2014$ base cost). Please also see Manitoba Hydro's response to CAC/MH I-021c.

See tables below for a cost breakdown of the project estimates for the US and Manitoba portions of the 750 MW US Interconnection.

750 MW US Interconnection

Energy Price	**Reference**
Discount Rate	**Reference**
Capital Cost	**Reference**

	Capital Costs (Millions of 2014$) Transmission US T/L	
FYB	Manitoba Side	US Side
2012	0.00	0.00
2013	0.00	0.00
2014	2.77	1.00
2015	5.55	1.21
2016	16.64	0.52
2017	24.95	0.00
2018	74.86	28.48
2019	74.86	10.30
2020	77.63	80.22
2021	0.00	0.00
2022	0.00	0.00
2023	0.00	0.00
2024	0.00	0.00
2025	0.00	0.00
2026	0.00	0.00
2027	0.00	0.00
2028	0.00	0.00
2029	0.00	0.00
2030	0.00	0.00
2031	0.00	0.00
2032	0.00	0.00
2033	0.00	0.00
2034	0.00	0.00
2035	0.00	0.00
2036	0.00	0.00
2037	0.00	0.00
2038	0.00	0.00
2039	0.00	0.00
2040	0.00	0.00
2041	0.00	0.00
2042	0.00	0.00
2043	0.00	0.00
2044	0.00	0.00
2045	0.00	0.00
2046	0.00	0.00
2047	0.00	0.00
2048	0.00	0.00
2049	0.68	0.00
2050	1.37	0.00
2051	4.11	0.00
2052	6.16	0.00

(Table continued on next page)

	Capital Costs (Millions of 2014$) Transmission US T/L	
FYB	Manitoba Side	US Side
(Table continued from previous page)		
2053	18.49	0.00
2054	18.49	0.00
2055	19.18	0.00
2056	0.00	0.00
2057	0.00	0.00
2058	0.00	0.00
2059	0.00	0.00
2060	0.00	0.00
2061	0.00	0.00
2062	0.00	0.00
2063	0.00	0.00
2064	2.09	0.00
2065	4.18	0.00
2066	12.53	0.00
2067	18.79	0.00
2068	56.37	0.00
2069	56.37	0.00
2070	58.46	0.00
2071	0.00	0.00
2072	0.00	0.00
2073	0.00	0.00
2074	0.00	0.00
2075	0.00	0.00
2076	0.00	0.00
2077	0.00	0.00
2078	0.00	0.00
2079	0.00	0.00
2080	0.00	0.00
2081	0.00	0.00
2082	0.00	0.00
2083	0.00	0.00
2084	0.68	0.00
2085	1.37	0.00
2086	4.11	0.00
2087	6.16	0.00
2088	18.49	0.00
2089	18.49	0.00
2090	19.18	0.00
Salvage Value	4.78	0.00
PV @ 5.05%	243.42	93.75

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 3; Page No.: 91

QUESTION:

Please reconcile the $350 M (per Chapter 2, page 58) noted as the cost for the Manitoba portion of the Manitoba-Minnesota Transmission Project with the value (prior to discounting) included in Appendix 9.3, Table 001 (page 91).

RESPONSE:

The proposed Manitoba-Minnesota Transmission project by definition is the portion of the 750MW interconnection in southeastern Manitoba which connects at the border with Minnesota Power's proposed Great Northern Transmission Line.

Following is a table which reconciles the $350 million from Chapter 2, page 58 with the values shown in Table 001 of Appendix 9.3. The estimate of $350 million is an updated capital cost estimate for the Manitoba portion of the 750 MW US Interconnection. The additional cost, approximately $19 million in-service dollars is for a new phase shifting transformer. This information was not available for inclusion in the economic analysis in the NFAT submission.

1 **Manitoba-Minnesota Transmission Project**

	Reference Dollar Year	(Millions of $)
Appendix 9.3, Table 001 (2014$)	2014	277
Base Estimate (2012$)	2012	267
Interest and Escalation		63
Sunk Cost	2012	1
In-Service Cost	2020	331
Capital Revision (In-Service Cost)	2020	19
Capital Update Chapter 2, Page 58 (In-Service Cost)	2020	350

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.4.5; Page No.: 59

QUESTION:

Does the $350 M cost of the Manitoba portion change if the interconnection is a 230 kV as opposed to a 500 kV line and, if so, what is the cost on a comparable basis?

RESPONSE:

Yes, the Manitoba portion of the cost will change if a 230 kV interconnection is pursued rather than a 500 kV interconnection. The in-service cost for the Manitoba portion is estimated to be $100 million for the 230kV (250MW) interconnection as compared to the estimate of $350 million which is the most recent update of the in-service cost for the Manitoba portion of the 500 kV (750 MW) interconnection.

Please also see Manitoba Hydro's response to CAC/MH I-018b.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 3; Page No.: 96

QUESTION:

With respect to Table 006 please breakdown the Transmission-U.S. T/L column of costs as between those applicable to the Manitoba portion of the line vs. the US portion of the line.

RESPONSE:

Economic Summary Table 006 provides the economic evaluation documentation for Plan 13, K19/C25/250MW plan. The Transmission-U.S. T/L column of costs (2014$ base cost, not including interest or escalation) shown in Table 006 are only applicable to the Manitoba portion of the line. Manitoba Hydro is not responsible for any costs associated with the US portion of the 250 MW line.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.4.5; Page No.: 59

PREAMBLE: At the Technical Conference on September 6, 2013 the Business Case and Risk Assessment presentation (Slide 13) made reference to a decrease in the capital costs for the US portion of the 750 MW interconnection

QUESTION:

What is the revised (from $700 M - US 2020 $) cost of the US portion of the interconnection?

RESPONSE:

The most recent estimate for the US portion of the interconnection ranges between $400M and $600M (2013 US $) with midpoint of $507M (2013 US $). The estimated cost has been reduced due to refinement of the Blackberry station estimate as well as reduced transmission line estimates. This most recent estimate was not available to Manitoba Hydro for inclusion in the NFAT Business Case.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 3; Page No.: 96

QUESTION:

Please reconcile the $700 M (per Chapter 2, page 59) noted as the cost for the US portion of the Manitoba-Minnesota Transmission Project with the value for this portion of the Transmission - US T/L (prior to discounting) included in Appendix 9.3, Table 001 (page 91). (Note: It is recognized that Table 001 only includes the portion of the capital cost that Manitoba Hydro will be responsible for)

RESPONSE:

The Manitoba–Minnesota Transmission Project by definition is the Manitoba portion of the proposed US interconnection. The US side of the proposed interconnection is entitled the Great Northern Transmission Line (GNTL).

For the US portion of the new interconnection included in Appendix 9.3, Table 001, in order to model the financials, 18% of the capital was assumed to be funded directly during construction and 22% was assumed to be funded during operation (both were included in analysis). This is consistent with arrangements that were being discussed when the models were developed.

The requested reconciliation is provided in the table below.

1 **Great Northern Transmission Line Project**

Row #	Capital Costs	Reference Dollar Year	(Millions of $)
1	Nominal Estimate for US portion of the interconnection (US 2020$)	2020	$712
2	Base Estimate for US portion of the interconnection (US 2012$)	2012	$579
3	Assumed MH capital costs for US portion of the interconnection (CDN 2012$)	2012	$117
4	Assumed MH capital costs for US portion of the interconnection (CDN 2014$)	2014	$122
5	Assumed MH capital costs for Manitoba portion of the interconnection (CDN 2014$)	2014	$277
Row 4 + Row 5	Appendix 9.3 Table 001	2014	$399

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.1.1.1; Page No.: 5

QUESTION:

What assumptions were made regarding ownership; partnership (i.e. common-unit s. preferred-unit) by the KCNs and loans to KCNs by Manitoba Hydro for purposes of the financial analysis in Chapter 12.

RESPONSE:

The NFAT financial evaluation assumes that the KCN invest in the Keeyask project under the preferred ownership arrangement. Under the preferred arrangement, there are no equity loans to the KCN. There are distribution credit facility and revenue advances that are projected to be repaid by the KCN to Manitoba Hydro through future distributions from the partnership.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.1.1.1; Page No.: 5

PREAMBLE: Each KCN partner can choose to invest as a common-unit partner or a preferred-unit partner.

QUESTION:

What is the sensitivity of the financial projections (e.g. debt/equity ratio and average annual rate increases) to changes in these assumptions? Please provide an illustrative example.

RESPONSE:

The non-controlling interest shown in the pro forma financial statements in Appendix 11.4 reflects preferred dividends projected to be paid to the KCN. Under common ownership, non-controlling interest would reflect KCN's share of projected net income or losses. Additionally, Manitoba Hydro's projected net finance expense would be reduced by interest income accruing on equity loans to the KCN. Estimated impacts would be an approximate 1% strengthening of the debt/equity by 2031/32 resulting in slightly lower even-annual rate increases required to achieve the target 75:25 debt/equity ratio.

REFERENCE: Appendix 15.1 Keeyask Aboriginal Partnership Business Risks; Page No.: 5

PREAMBLE: Appendix 15.1 states "a preferred investment will not have to carry the burden of significant loans from Manitoba Hydro".

QUESTION:

Please explain this statement and, in doing so, clarify whether KCNs choosing to be preferred partners are required to source their equity investment from borrowing sources other than Manitoba Hydro.

RESPONSE:

In the common share arrangement, the KCN have the opportunity to take on equity loans to obtain a larger number of shares than they otherwise would be able to for the amount of cash equity they may have available.

In the preferred share arrangement, the KCN do not take on equity loans to leverage their cash and thus do not have the significant loans associated with the common share option.

KCNs choosing to be preferred partners are required to provide their cash equity investment from their own source of funds. Manitoba Hydro will not provide loans for this purpose. Should the KCN seek to borrow from other sources for their cash equity, those borrowing arrangements cannot involve the KCN using their Keeyask shares as collateral nor can the lender have recourse to the KCN dividends.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.1.1.1; Page No.: 5

QUESTION:

Please explain precisely how the annual distributions are determined for KCNs that choose to be preferred-unit partners as opposed to those that choose to be common-unit partners.

RESPONSE:

The KHLP will make distributions to partners in accordance with Article 6.09 of the Limited Partnership Agreement (Schedule 1-1 of the Joint Keeyask Development Agreement) between Manitoba Hydro and the KCN. In summary, preferred distributions to the KCN are based on a share of adjusted gross revenues as follows for each 1% of KCN ownership interest:

(a) 0.8% of adjusted gross revenues less than or equal to two hundred and fifty million ($250,000,000) dollars; plus

(b) 1.2% of adjusted gross revenues greater than two hundred and fifty million ($250,000,000) dollars but less than or equal to one billion ($1,000,000,000) dollars; plus

(c) 1.6% of adjusted gross revenues greater than one billion ($1,000,000,000) dollars.

Adjusted gross revenues are partnership revenues determined in accordance with the Power Purchase Agreement (Schedule 1-4 of the Joint Keeyask Development Agreement) between Manitoba Hydro and KHLP adjusted to remove:

- transmission charges;
- amortization and finance expense on:
  - pre-construction costs, and
  - capital costs incurred subsequent to the in-service date (excluding capital costs greater than $40 million in constant 2017$).

Under the common ownership arrangement, the partnership would distribute the amount of distributable cash equal to KCN's proportionate share of common ownership interest. Distributable cash is excess cash, if any, in any given fiscal year required to maintain the partnership's debt ratio at seventy five percent.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.1.3.1; Page No.: 20

QUESTION:

Have the adverse effects agreements with each of the KCNs been finalized? If not, with which parties are the agreements still to be concluded?

RESPONSE:

The adverse effects agreements have been finalized with all four Keeyask Cree Nations.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.4.5; Page No.: 58

QUESTION:

Does the 250 MW sale to Minnesota Power effectively require all of the increase in on-peak export capacity that would be provided by a new 230 kV line?

RESPONSE:

The actual transfer capacity level of the 230 kV US interconnection is subject to final design. For planning purposes it is assumed to have 250 MW of export capability and will be fully utilized by the 250 MW Minnesota Power Sale Agreement.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.4.5; Page No.: 58

QUESTION:

Does the 250 MW sale to Minnesota Power and the 200 MW (incremental) sale to WPS effectively require 450 MW of the 750 MW on-peak export capacity increase that would be provided by a new 500 kV line?

RESPONSE:

Yes, the 250 MW Minnesota Power Sale and the 300 MW Wisconsin Public Service Power Sale require a total of 450 MW of the 750 MW of export capability provided by the 500 kV interconnection as there is currently 100 MW of transmission capability to Wisconsin.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.4.5; Page No.: 59

PREAMBLE: The Application states "for evaluation purposes it is assumed that the cost of this new transmission service will be reflected in the sale arrangement with MP and WPS"

QUESTION:

Would use of the Manitoba-Minnesota Transmission facilities for these sales be subject to Open Access Tariff?

RESPONSE:

The use of these facilities will be covered by the Manitoba Hydro Tariff in Manitoba and the MISO tariff in the USA.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.4.5; Page No.: 59

PREAMBLE: The Application states "for evaluation purposes it is assumed that the cost of this new transmission service will be reflected in the sale arrangement with MP and WPS"

QUESTION:

If yes, who would "pay" the actual tariff and who would "receive" the tariff revenues, given Manitoba Hydro only has a 40% investment under the MISO OATT arrangements?

RESPONSE:

The requesting party for the transmission service would "pay" the tariff and any revenues received by MISO would be allocated to all of the MISO Transmission Owners as provided by the revenue sharing arrangements included in the tariff.

As the new 750 MW interconnection will be participant funded the MISO Tariff provides that the funders of the line will not also be responsible for paying additional transmission charges for use of the line.

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: 3.2; Page No.: 8 (attachment included in Technical Reports)

PREAMBLE: In catalogue no 91-520-x, http://www.statcan.gc.ca/pub/91-520-x/91-520-x2010001-eng.pdf Statistics Canada provides extensive analysis of a series of scenarios examining population growth, for low growth, medium growth and high growth for Manitoba, Canada and other provinces. An excerpt from Table 3.1 (attached) suggests that Manitoba is for far more likely to grow at below the Canadian average than above the Canadian Average. It also suggests (based on medium growth scenarios 1 through 4), that the best guess for Manitoba population growth would be at or slightly below 1%.

QUESTION:

Please explain why Hydro believes its estimates are more reliable that those at Statistics Canada.

RESPONSE:

The forecasting methodology used by Manitoba Hydro to develop its annual Economic Outlook uses a consensus view of several well known and respected independent sources and not any one source directly. Statistics Canada, while also well known and respected, does not provide annual forecasts of variables such as population on a regular basis and therefore, is not included in the suite of forecasters used by Manitoba Hydro to develop its Economic Outlook. Manitoba Hydro notes that the report cited by CAC is the most recent population study published by Statistics Canada and includes forecasts based on populations observed in 2009.

Manitoba Hydro cannot comment on the reliability of the Statistics Canada population forecast other than to note that the Statistics Canada medium growth scenarios of approximately 1%, as noted in the preamble to the question is very similar to the growth rate in Table A-1 of the 2013 Economic Outlook, prepared in the spring of 2013 and filed as Appendix G.

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: 3.2; Page No.: 9

QUESTION:

Does the EIA have a projection for U.S. load growth up to 2022? If so, what is the projected annual growth rate?

RESPONSE:

As noted on Chapter 3, page 1, lines 21-23 of the NFAT filing, the Energy Information Administration's (EIA) Annual Energy Outlook 2013 reference case projects overall US load growth of 28% between 2011 and 2040 (0.9% per year).

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: 3.4.4; Page No.: 33

QUESTION:

With respect to line 18, by what other rate mechanisms is the value of capacity recovered

RESPONSE:

The MISO Day-Ahead and Real-time energy markets do not explicitly provide compensation for all fixed costs, including capital costs, of keeping a generator available for operation; they are energy markets. Additional generator revenue, referred to as the value of capacity, is generally required to cover the fixed annual costs of keeping a generator available for service. Load serving entities in MISO must supply or purchase both energy and generation capacity to serve their load. Generation capacity can be self supplied from generation owned by the load serving entity, purchased under a bilateral contract, or purchased from the annual auction under the MISO Resource Adequacy Construct.

Investor owned utilities in the US typically have two primary cost categories -- capital investments and operating expenses. Operating expenses for an investor owned thermal utility consist primarily of generating-plant fuel costs, purchased power (such as from the MISO energy markets) and transmission services, and labor. Fuel and power purchased costs vary depending on how much power is produced. Utilities generally do not earn a rate of return on fuel and power purchased, rather these costs are flowed through to the consumer without markup much like the natural gas costs of Centra Gas in Manitoba. As fuel and power purchased costs is a significant component of many U.S. utility rates, volatile fuel costs could, in theory, require frequent rate adjustments. To avoid that, many states have adopted fuel cost adjustment clauses that allow utilities to adjust rates periodically without a lengthy rate hearing.

Investor owned utilities in the US typically earn their rate of return on invested capital on an amount that is called the rate base. Regulators set the rate of return in a range that allows a utility to earn a profit on its investment and attract capital at favorable rates (compared to bank borrowing). Payment of the rate of return allows a utility (and its investors) to recover its investment through rates. Regulator approved capital investments include generating plants, transmission and distribution systems, and other infrastructure such as office buildings. Once accepted for inclusion in rate base by the regulator, a rate of return would be earned on the new capital investment – which is how the capital costs or the value of capacity is recovered.

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: 3.4.4; Page No.: 34

QUESTION:

With respect to lines 14-16, will construction of the 750 kV interconnection (in particular the US portion), resolve any of the transmission constraints that are currently serving to decrease prices at the Minnesota Hub?

RESPONSE:

Manitoba Hydro is not proposing to build a 750 kV interconnection. As indicated in Section 2.4 page 56 of the NFAT filing, "The proposed Manitoba-Minnesota Transmission Project is a 750 MW, 500 kV AC transmission line."

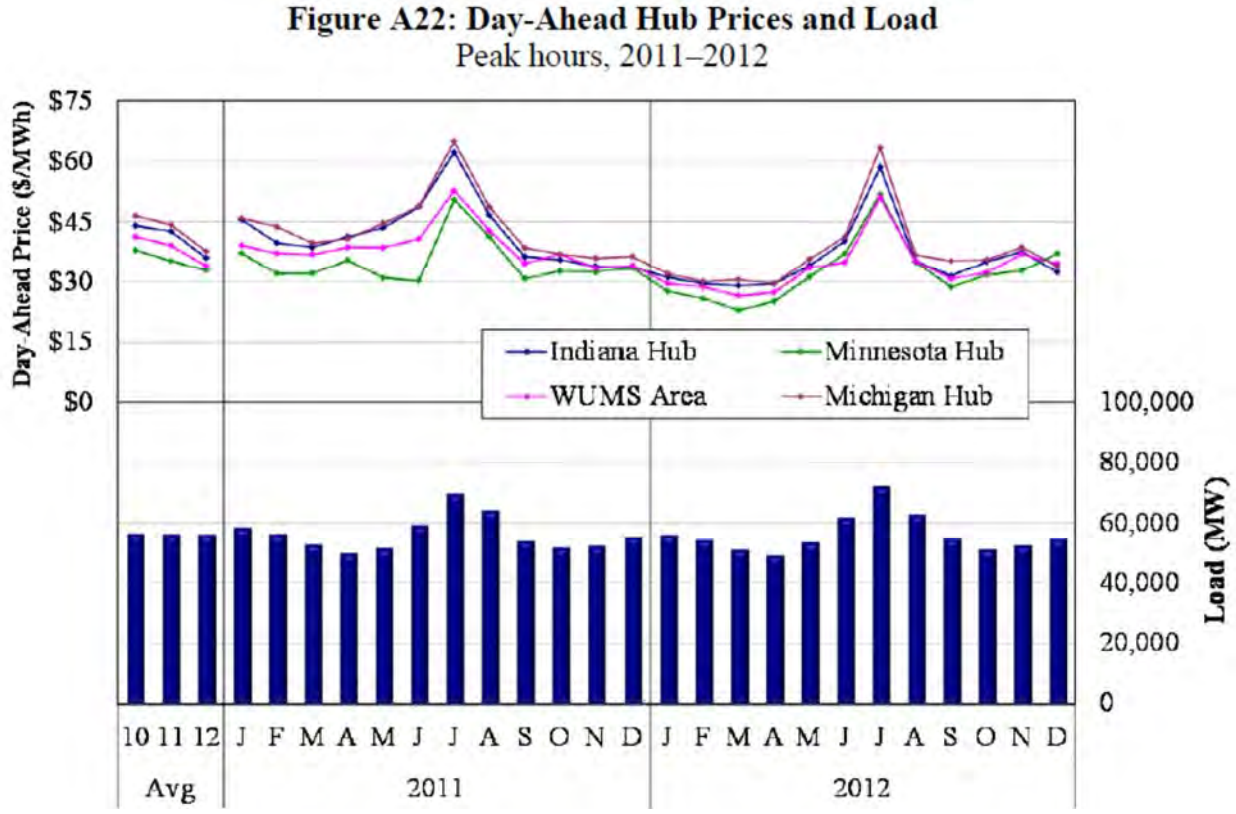
At the present time, there is minimal on-peak congestion from the Minnesota Hub to points further east in the MISO market and only relatively minor off-peak congestion from the Minnesota Hub to points further east in the MISO market. Manitoba Hydro analyzed the location prices for the Minnesota Hub in comparison with a weighted average price for all of MISO for the period January to July 2013. During this recent period, there was effectively no difference in On-Peak price (-0.5%) while Off-Peak prices are about 8% lower at Minnesota Hub versus the MISO average.

Data supplied by MISO's Monthly Market Assessment Reports January - July 2013

Section 1 - Market Price Analysis

Month-Yr	Day Ahead On-Peak Monthly Average			Day Ahead Off-Peak Monthly Average		
	Minn Hub	MISO	Difference %	Minn Hub	MISO	Difference %
Jul-13	$ 40.70	$ 40.87	0%	$ 24.73	$ 26.11	-5%
Jun-13	$ 35.86	$ 38.17	-6%	$ 21.78	$ 25.76	-15%
May-13	$ 37.97	$ 41.76	-9%	$ 22.43	$ 27.01	-17%
Apr-13	$ 42.59	$ 40.82	4%	$ 27.94	$ 30.01	-7%
Mar-13	$ 37.42	$ 37.55	0%	$ 27.47	$ 29.01	-5%
Feb-13	$ 32.69	$ 30.80	6%	$ 24.16	$ 24.84	-3%
Jan-13	$ 34.70	$ 33.19	5%	$ 24.84	$ 25.00	-1%
Jan-July 2013 Average	$ 37.42	$ 37.59	-0.5%	$ 24.76	$ 26.82	-7.7%

Historical data indicates the price spread between the Minnesota Hub and eastern hub has been narrowing since 2010, as indicated in Figure A22: Day-Ahead Hub Prices and Load[1].



[1] ANALYTICAL APPENDIX of the 2012 STATE OF THE MARKET REPORT FOR THE MISO ELECTRICITY MARKETS, prepared by Potomac Economics, page A35.

Historically, as shown in Figure A22, prices at eastern hubs such as the Indiana and Michigan hubs have been somewhat higher than the Minnesota hub. This differential is due in part due to the higher cost of eastern coal in comparison with western Powder River Basin (PRB) coal and mine mouth lignite coal in North Dakota, as well as the fact that the largest load centers are located in the eastern part of the MISO market footprint. Pricing differentials between two locations are driven by losses as well as congestion, and losses can be the larger factor. As noted in the Fall 2012 MISO Independent Market Monitor Report[2] prepared by Potomac Economics, transmission losses accounted for nearly 60 percent of the price spread between the Michigan Hub and the Minnesota Hub.

MISO has a regional transmission planning process, as outlined in Attachment FF (Transmission Expansion Planning Protocol) of the MISO Transmission and Energy Market Tariff. The regional transmission planning process results in a regional transmission plan (the Midwest Transmission Expansion Plan or MTEP) which identifies and implements more efficient and/or cost-effective regional transmission solutions. This regional transmission planning process, combined with the continued evolution of the MISO market design, appears to be easing transmission congestion.

As noted by Wisconsin's American Transmission Co., "By easing congestion on the system and providing access to lower-cost sources of generation, transmission investments help keep electric rates in check. When the Midwest wholesale energy market was established in 2005, the average locational marginal price within our service area [Wisconsin] was more than $10 higher per megawatt hour than the average in neighboring states. In 2012, the LMP was only 20 cents higher[3]."

In the future, Manitoba Hydro anticipates this regional transmission planning process will help minimize future congestion in the MISO market. However should Keeyask and Conawapa proceed without a new major interconnection, additional off-peak congestion at Minnesota Hub and at the

[2] IMM Quarterly Report: Fall 2012 September–November, as prepared by Potomac Economics, December 12, 2012 page 3.
[3] http://www.atc10yearplan.com/summary-report/introduction/

MHEB LMP node can be expected as a significant proportion of the surplus energy that these projects would produce would have to sold in the off peak hours.

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: 3.4.4; Page No.: 35

QUESTION:

Do the MISO electricity price forecasts obtained by Manitoba Hydro take into account the transmission constraints that are currently depressing prices at the Minnesota Hub?

RESPONSE:

The independent price forecast consultants prepare their price forecasts for the Minnesota Hub pricing location. Therefore, the consultant forecasts inherently consider the numerous market factors impacting prices at the Minnesota Hub, including congestion.

As noted in the response to CAC/MH I-031, at the present time, there is minimal on-peak congestion, and only relatively minor off-peak congestion, from the Minnesota Hub to points further east in the MISO market.

As also noted in the response to CAC/MH I-031), MISO has a regional transmission planning process, which Manitoba Hydro anticipates will help minimize future congestion in the MISO market.

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: 3.4.4; Page No.: 35

QUESTION:

If so, do the price forecasts assume the constraints will be eased/eliminated in the future and, if so, when?

RESPONSE:

As noted in the response to CAC/MH I-031, at the present time, there is minimal on-peak congestion, and only relatively minor off-peak congestion, from the Minnesota Hub to points further east in the MISO market. MISO has a regional transmission planning process, which Manitoba Hydro anticipates will help minimize future congestion in the MISO market.

More information on the specific assumptions of each price forecast consultant, including that with respect to transmission expansion and congestion, is contained with the individual price forecast consultant reports, which have been filed with the application as part of the CSI.

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: 3.4.4; Page No.: 36

QUESTION:

Please confirm that Figure 3.13 is taken from Slide 33 of Appendix 3.1.

RESPONSE:

Partially confirmed with respect to the Base Case.

The Base Case (dotted line) in Figure 3.13 in Chapter 3 represents the On-Peak Energy forecast at MINN HUB as provided by the Brattle Group and corresponds to the line labeled On-Peak Energy in the graph titled Annual Average Energy and Capacity Prices on Slide 33 of NFAT Appendix 3.1.

The line labeled Scenario 2: High CO2 (top of the range) in Figure 3.13 in Chapter 3 represents the On-Peak Energy forecast at MINN HUB for the High CO2 Price Scenario as provided by the Brattle Group and corresponds to the line labeled On-Peak Energy in the graph titled *Annual Average Energy and Capacity Prices* on Slide 13 of the *"Appendix – Forecast Results for Scenarios"* found at the end of NFAT Appendix 3.1.

The line labeled Scenario 11: Extreme Low (bottom of the range) in Figure 3.13 in Chapter 3 represents the On-Peak Energy forecast at MINN HUB for the Extreme Low Scenario as provided by the Brattle Group and corresponds to the line labeled On-Peak Energy in the graph titled *Annual Average Energy and Capacity Prices* on Slide 49 of the *"Appendix – Forecast Results for Scenarios"* found at the end of NFAT Appendix 3.1.

REFERENCE: Appendix 3.1 Long-Term Price Forecast for Manitoba Hydro's Export Market in MISO - The Brattle Group; Page No.: 33

QUESTION:

Does the All-In-Price shown on Slide 33 include the forecast price of capacity? Also, is it an All-In-Price for All Hours or for On-Peak Hours?

RESPONSE:

Manitoba Hydro can confirm regarding Slide 33 in Appendix 3.1 that:

- The All-In Price shown includes the forecasted price of capacity
- The All-In Price is the all hours energy price plus the price of capacity allocated over all hours of the year.

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: 3.4.4; Page No.: 36

QUESTION:

With respect to Figure 3.13, please provide a schedule that sets out the on-peak and off-peak opportunity price that Manitoba Hydro has received from US sales for each year since 2005 (expressed in US$).

RESPONSE:

Please see the table below which provides the information requested.

	U.S. OPPORTUNITY SALES		TOTAL	
	On Peak AvgPrice $US	Off Peak AvgPrice $US	Opportunity Sales AvgPrice $US	MISO Day Ahead AvgPrice $US
2005/06	59.12	29.50	40.10	41.98
2006/07	59.70	33.13	41.43	46.97
2007/08	64.36	31.88	43.10	47.29
2008/09	68.19	26.12	40.28	37.13
2009/10	28.19	16.79	21.27	23.40
2010/11	31.05	20.33	24.17	25.25
2011/12	28.46	18.82	22.67	22.58
2012/13	28.68	20.18	25.09	24.12

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: 3.4.4; Page No.: 36

PREAMBLE: The Submission to the CEC regarding the need for the Wuskwatim Project identified each of the external parties that provided exports price forecasts to Manitoba Hydro and provided a brief discussion regarding the basis and direction of each forecast.

QUESTION:

As provided in the submission to the CEC regarding the Wuskwatim Project, please identify the independent price forecast consultants used by Manitoba Hydro for its current forecast and provide a brief discussion of the basis for and direction of each forecast. If this cannot be provided publicly, please explain why such is the case now whereas it was provided in the past.

RESPONSE:

As noted in Manitoba Hydro's responses to PUB/MH I-286a) and PUB/MH I-013b), Manitoba Hydro considers the identification of the names of the individual price forecast consultants, beyond the identification of The Brattle Group as one of the price forecasts consultants, to be Commercially Sensitive Information as it could facilitate recreation of Manitoba Hydro's price forecast by export customers, which could harm Manitoba Hydro in negotiation of contracts for export sales.

As previously noted, Manitoba Hydro has already filed forecasts from the individual price forecast consultants that were used to create the natural gas and electricity export forecasts as part of the NFAT filing as Commercially Sensitive Information (CSI). The information on the identification of the individual price forecast consultants is contained within the CSI information.

Manitoba Hydro notes that the price forecast disclosure for the 2013 NFAT review has many similarities to the 2003 NFAT review for Wuskwatim. In the 2003 NFAT, Manitoba Hydro's reference forecast was not provided, but a representative forecast from the consultant DRI-WEFA is provided. For 2013, a similar representative forecast has also been provided – this time from The Brattle Group (Appendix 3.1). It is correct to note that for the 2013 review, Manitoba Hydro is not publically identifying the other independent price forecast consultants and is not providing a synopsis of their work as was done in 2003, for the reasons outlined below. In the place of the short synopses provided in 2003, Manitoba Hydro has provided an entire new chapter in the 2013 review, specifically Chapter 3 – Trends and Factors Influencing North American Energy Supply. Chapter 3 provides the context and the notable trends and factors currently influencing electricity markets and resource planning decisions. Chapter 3 references a number of publically available information sources, including the US DOE EIA, NERC, US EPA, and MISO data. Two factors have changed significantly regarding price forecast disclosure since the 2003 NFAT review for Wuskwatim. First, there is a significantly heightened awareness of commercially sensitive information, how it could facilitate recreation of Manitoba Hydro's price forecast, and how it could harm Manitoba Hydro in negotiation of contracts for export sales. The presence of the MISO market itself has served to increase competition. Export customers do review Manitoba Hydro's regulatory filings to improve their understanding of Manitoba Hydro's system, costs and future price expectations, and can use any sensitive information found to their advantage in power sales negotiations. This is to be expected, as Manitoba Hydro also reviews customer's regulatory filings such as referenced in Chapter 6, Section 6.2 Manitoba Hydro's Major Export Customer's Perspective of the 2013 NFAT filing. Therefore Manitoba Hydro must be extremely careful that commercially sensitive information is not directly released, or is able to be recreated through information released. Routine posting of regulatory filings on the internet, as has occurred over the last ten years, has made such customer/competitor monitoring activities much easier and it now requires greater care to prevent the inadvertent release of commercially sensitive information.

Second, the price forecast consultants themselves have a significantly heightened sensitivity to the sharing or public release of what they consider to be their propriety intellectual property. Agreements with price forecasting consultants generally include a requirement not to publically disclose the information unless written permission is obtained from the consultant.

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: 3.4.4; Page No.: 36

PREAMBLE: The Submission to the CEC regarding the need for the Wuskwatim Project provided details regarding the high and low export price forecasts used in the economic analyses.

QUESTION:

Please confirm that the data provided in Appendix 11.3 of the current application regarding the unit export revenues is similar to that provided by Manitoba Hydro in its submission to the CEC regarding Wuskwatim. If not, what is the difference?

RESPONSE:

Manitoba Hydro can confirm that the term "Average Export Price" used in the context of Figure 5.9 of Chapter 5 of the April 2003 Need for and Alternatives to Wuskwatim Project filing is comparable to the term "Average Unit Revenue" as referenced in Chapter 11 page 5 and Appendix 11.3 of the 2013 NFAT submission.

Manitoba Hydro notes that the Average Export Price shown in Figure 5.9 of Chapter 5 of the April 2003 Need for and Alternatives to Wuskwatim Project filing is expressed in Constant 2002 Canadian Dollars (i.e. dollars which do not escalate with inflation) whereas Figure 3.13 of Chapter 3 of the NFAT 2013 filing is listed in Constant 2013 U.S. Dollars. Further, it is important to note that the Average Unit Revenue/Cost data provided in NFAT 2013's Appendix 11.3 are in nominal dollars which escalate with inflation.

Please see Manitoba Hydro's response to PUB/MH I-235b.

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: 3.4.4; Page No.: 36

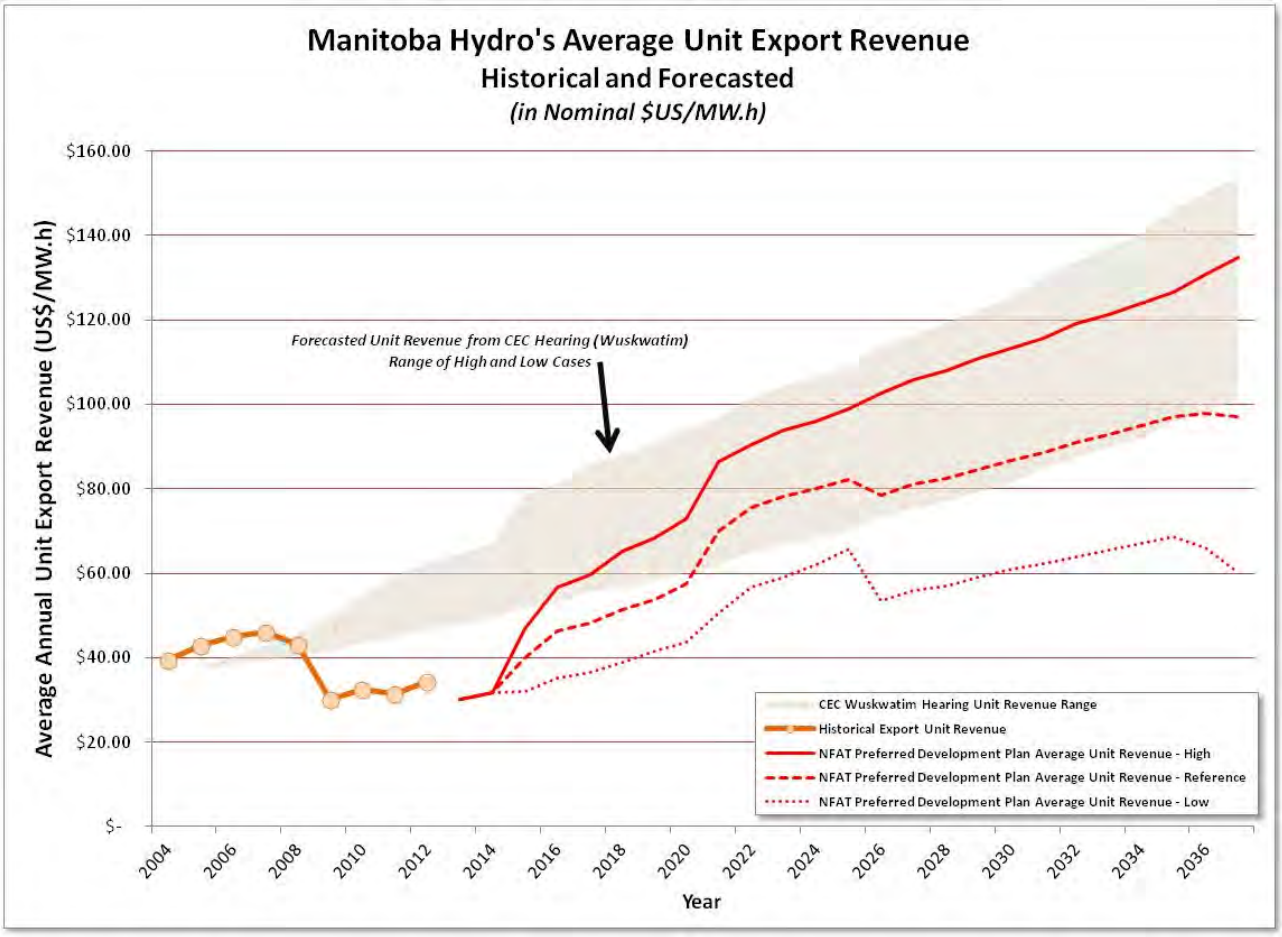
PREAMBLE: The Submission to the CEC regarding the need for the Wuskwatim Project provided details regarding the high and low export price forecasts used in the economic analyses.

QUESTION:

Please provide a chart that compares the high-low range of export prices as filed with the Submission to the CEC regarding Wuskwatim (Chapter 5, Figure 5.9) with the actual export revenues for the years up to 2012/13 and the current high-low forecast range for export prices forecast by Manitoba Hydro.

RESPONSE:

It should be noted that the high-low range of export prices provided in Chapter 5, Figure 5.9 of Submission to CEC regarding Wuskwatim represents average unit revenues. The chart below includes the information from Figure 5.9 of the Wuskwatim submission as well as the forecasted average unit revenues, for the High, Reference and Low Energy Price scenarios for the Preferred Development Plan as provided in Appendix 11.3 of the NFAT 2013 submission.


Manitoba Hydro's Average Unit Export Revenue
Historical and Forecasted
(in Nominal $US/MW.h)
Average Annual Unit Export Revenue (US$/MW.h)
$160.00
$140.00
$120.00
$100.00
$80.00
$60.00
$40.00
$20.00
$-
Forecasted Unit Revenue from CEC Hearing (Wuskwatim)
Range of High and Low Cases
CEC Wuskwatim Hearing Unit Revenue Range
Historical Export Unit Revenue
NFAT Preferred Development Plan Average Unit Revenue - High
NFAT Preferred Development Plan Average Unit Revenue - Reference
NFAT Preferred Development Plan Average Unit Revenue - Low
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
Year

REFERENCE: Chapter 4: The Need for New Resources; Section: 4.1; Page No.: 3

QUESTION:

What is the basis for the statement that Manitoba Hydro's DSM programs are "industry-leading"? In particular, please provide any evidence in the possession of Manitoba Hydro comparing its forecast increment. DSM savings as compared to other Canadian or other North American utilities.

RESPONSE:

Manitoba Hydro's use and interpretation of "industry-leading" is in reference to:

- Having a full suite of programs which pursue all economic opportunities;
- Having complementary programs which support direct DSM programs (e.g. financing services and generic educational/marketing efforts to promote an energy efficient culture, all energy efficient opportunities, including those opportunities which go beyond those specifically targeted with programs);
- Having complementary efforts at transforming the market in terms of standards, codes and policy creation; and
- Having a sustained impact and presence in the market over a meaningful period of time.

Manitoba Hydro has maintained a consistent presence in the market since Power Smart was first introduced as the Corporation's brand for energy efficiency in 1990. Despite the various economic and business conditions experienced in the energy industry at various times during the last 25 years, Manitoba Hydro has always maintained a base level of programs and messaging whereas some utilities drastically declined or eliminated their efforts all together.

Due to this commitment, approximately 92 per cent of Manitoba Hydro customers are aware of the Manitoba Hydro Power Smart brand and 83 per cent of customers who recognize Power Smart strongly agree the Power Smart brand means (or represents) "energy efficiency". In

addition, 79 per cent of Manitoba Hydro customers are satisfied with Manitoba Hydro's efforts to encourage energy efficiency.

In addition to Power Smart's overall presence in the market, the current program portfolio is one of the most comprehensive offered in North America demonstrating Manitoba Hydro's commitment to supporting energy efficiency. With over 20 programs and numerous technologies supported, Manitoba Hydro offers solutions for improving energy efficiency in a building whether the customer is single family dwelling, a multi-unit residential building, an industrial pulp mill or a small convenience store.

One of the best examples of Manitoba Hydro's leading position with respect to innovative market intervention strategies is on-bill financing. The Power Smart Residential Loan was first launched in 2001 and continues to finance over 5000 customer projects annually. Building on the success of this complementary and supporting DSM initiative, Manitoba Hydro has offered subsequent on-bill financing programs including the Earth Power Loan Program for geothermal heat pumps and solar hot water systems, the PAYS (Pay As You Save) Residential Loan, and the PAYS Commercial Loan. All of these complementary and supporting financing services play a key role in successfully transforming the market for specific technologies. Other utilities and industry researchers have, and continue to, contact Manitoba Hydro to learn about these best practices programs. Lawrence Berkley Laboratories, the International Energy Agency, ESource, BC Hydro and the Ontario Ministry of Energy are a few of the organizations that have engaged Manitoba Hydro in their research efforts for best practice financing programs.

Additionally, a number of Manitoba Hydro's Power Smart programs targeting specific opportunities have also been sought out and replicated as industry leading programs with three examples being the Commercial Building Optimization Program (CBOP), the Commercial Refrigeration Program (CRP), and the Water and Energy Saver Program (WESP). The CBOP, first offered in 2006, was the first program of its kind in Canada. Manitoba Hydro's leadership in bringing a full building retro commissioning program into the market led Natural Resources

Canada (NRCan) to use the program's Optimization Toolkit as the basis for a nationwide standard and training package for commissioning services to practitioners and existing building operators. With Manitoba Hydro's cooperation and support, BC Hydro replicated the CRP after a National grocery chain inquired as to the utility's lack of programming in the area of commercial refrigeration and pointed to the positive partnership with Manitoba Hydro. Hydro Quebec consulted extensively with Manitoba Hydro staff prior to designing their recently launched water and energy saving program. Manitoba Hydro provided all the information that had been researched and designed for the WESP including energy savings, available products, program delivery channels and the criteria for a Request for Proposals to obtain an external firm to provide products and services for the Program in order to expedite Hydro Quebec's launch of their own WESP.

Manitoba Hydro is also a leader in the Bioenergy programming and successful showcasing of leading edge demonstrations of five conversion pathways from bioenergy to electricity. The recently completed multi measure initiatives encompassing an Organic Rankine Cycle waste heat to electricity system, a modular gasifier, a pyrolysis oil replacement of fossil fuel, an anaerobic digester, and a pilot plant carbonization of forest residues system is at the forefront North American innovation. Two of the projects were promoted as among industry firsts by their respective manufacturers.

To gauge leadership in delivering DSM, one should also include an assessment of strategies employed outside of the more visible market delivered programs and determine to what level a utility or administrator is involved at influencing the market in terms of standards, codes and policy creation. Manitoba Hydro influences energy efficiency at all three of these levels. Manitoba Hydro has longstanding involvement at CSA's Standing Committee on the Performance of Energy Efficiency and Renewables (SCOPEER) assisting with the creation of minimum performance standards for energy consuming products; these standards form the basis of further intervention strategies whether they are utilized in the creation of codes, regulations or voluntary programs and are therefore essential to the entire long term market

transformation strategy. Manitoba Hydro has chaired and been a participant on over 25 committees to develop these standards and continues to be one of three leading utilities with respect to commitment in terms of technical resources and budget; and the top contributor on a per capita basis.

The new National Energy Code for Buildings 2011 (NECB 2011) is a code document that originated through Manitoba Hydro's chairing of the Manitoba Energy Code Advisory Committee which produced a report *"Building Energy, Building Leadership: Recommendations for the adoption, development, and implementation of a commercial building energy code in Manitoba".* One of the key recommendations contained within the report was to update the Model National Energy Code for Buildings (1997). This recommendation resulted in the formation of the national working group, the Building Energy Code Collaborative (BECC), which was originally led by Manitoba Hydro as the Chair. The BECC was successful in its objective to convince Natural Resources Canada to invest in an update to the code and Manitoba Hydro staff were invited to assist in the development of the NECB 2011 as well as worked on the local committee to ensure the adoption of the code in Manitoba.

Finally, Manitoba Hydro has been, and continues to be, heavily involved with assisting the Manitoba Provincial Government with policies related to ensuring energy efficiency is incorporated into government operations. Manitoba Hydro staff were key collaborators in the development of the 2007 Green Building Policy for Government of Manitoba Funded Projects, by way of representation on the steering committee, working groups, and technical sub-committees.

Derived from the successful implementation of the 2007 Green Building Policy, work now continues with respect to the future development of green building standards for existing buildings and leased accommodations. Manitoba Hydro staff have joined the steering committee and working group for a provincial interdepartmental group focusing on existing building standards and practices.

To further strengthen the province's Green Building Policy and through considerable contribution from Manitoba Hydro staff, The Green Building Regulation included in Manitoba's Climate Change and Emissions Reduction Act (CCERA), officially came into force as of April 1, 2013. Among its green building requirements, the new regulation states that Power Smart designation must be obtained through Manitoba Hydro's New Buildings Program for all new buildings owned, leased, or operated by the provincial government or a provincial government agency, and all new construction projects for which the provincial government provides capital funding.

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 55

QUESTION:

Please describe the change in assumptions regarding future domestic electricity price increases as between the 2012 (Appendix C) and the 2013 Load Forecasts (Appendix D).

RESPONSE:

The domestic electricity price increases referenced in the 2012 Load Forecast were based on rate increase projections contained in the Integrated Financial Forecast IFF-11. The nominal electricity price was forecast to increase by 2.0% in 2012/13, increase 3.5% per year until 2023/24 and then increase by 2.0% per year throughout the rest of the forecast period.

The domestic electricity price increases referenced in the 2013 Load Forecast were based on rate increase projections contained in the Integrated Financial Forecast IFF12, where the nominal electricity price is forecast to increase by 3.5% in 2013/14, and then increase by 3.95% per year through the rest of the forecast period.

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 55

QUESTION:

Please outline the impact this change in assumptions regarding future electricity prices had on the 2013 (versus 2012) Load Forecast for the Residential, General Service Mass Market and General Service Top Consumers sectors.

RESPONSE:

The 2012 Load Forecast used the electricity to natural gas price ratio to estimate the number of new homes in gas available areas choosing electric or natural gas heating. Although the electricity price forecast was listed as an economic assumption at page 55 of the 2013 Load Forecast, under the 2013 Load Forecast the electricity to natural gas price ratio is no longer used as the impact of the ratio was determined to have a limited effect.

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 55

QUESTION:

Are the electricity price increase assumptions used in the 2013 Load Forecast (Appendix D) consistent with the electricity price increases in IFF12 (Appendix C)? If not, what are the differences?

RESPONSE:

Please see Manitoba Hydro's response to CAC/MH I-039(a).

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 55

PREAMBLE: During the 2008/09 GRA Manitoba Hydro provided information on own price elasticities of demand by customer class

QUESTION:

Please provide the own price elasticities by customer class filed in the 2008/09 GRA and update the values for each customer class if the estimates have been revised.

RESPONSE:

Please see the attachment to this response. These estimates were prepared by NERA Economic Consulting as part of the "Review of Time of Use and Inverted Electric Rate Structures for Application in Manitoba". The report was prepared for Manitoba Hydro in 2005 and the estimates were based on studies involving other jurisdictions.

PUB/MH I-83

Reference: Marginal Costing

a) Please explain how marginal costing at current levels would reduce domestic loads in each of the various customer classes:

- **Residential**
- **GSS**
- **GSM**
- **GSL <60**
- **GSL 60-100**
- **GSL >100**

ANSWER:

At a very high level, if marginal cost pricing for domestic customer classes were adopted, the long term load reduction, relative to a regime in which current pricing methodology is maintained would be as follows.

Residential, General Service Small Non-Demand	7%
General Service Small Demand, General Service Medium,	9%
General Service Large < 30 kV	11%
General Service Large > 30 kV	26%

These approximate impacts were derived on the basis of the following:

Current rates:

Residential, General Service Small Non-Demand, runoff	6.0 cents/kW.h
General Service Small Demand, General Service Medium, average	5.1 cents/kW.h
General Service Large < 30 kV	4.1 cents/kW.h
General Service Large > 30 kV	3.2 cents/ kW.h

Marginal Cost based rates (Generation, Transmission expansion, Distribution expansion):

Residential, General Service Small Non-Demand	7.6 cents/kW.h
General Service Small Demand, General Service Medium	7.6 cents/kW.h
General Service Large < 30 kV	7.6 cents/kW.h
General Service Large > 30 kV	6.8 cents/kW.h

Own Price Elasticity of Demand

Residential, General Service Small Non-Demand, runoff	-.056
General Service Small Demand, General Service Medium, average	-.06
General Service Large < 30 kV	-.06
General Service Large > 30 kV	-.125

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 55

QUESTION:

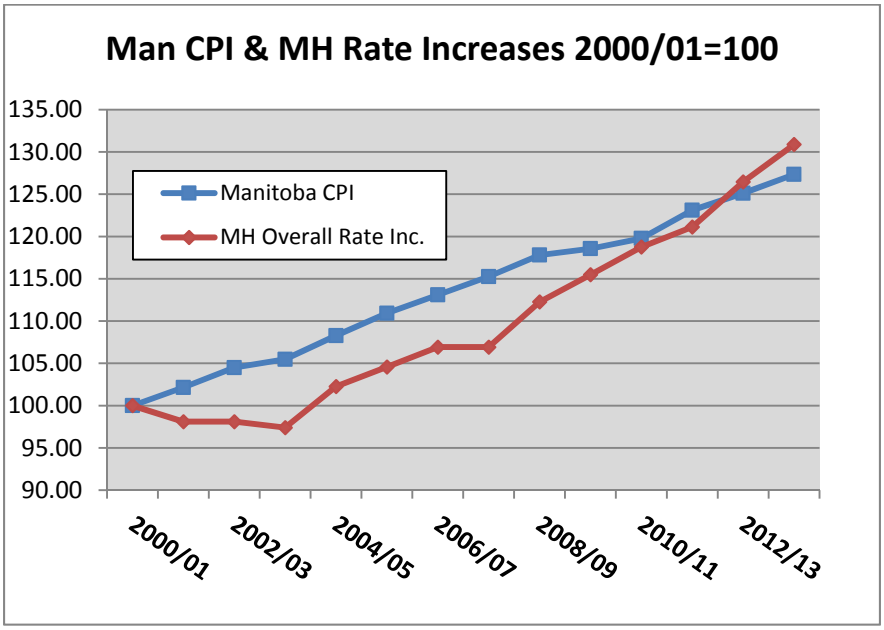
Please provide a schedule that, starting in 2000, identifies the annual percentage increase in CPI and MH rates for each year through to 2013 and the resulting year to year as well as the overall average annual increase for both over the full period.

RESPONSE:

The following table and chart depict that between 2000 and 2013, the average percentage increase in Manitoba CPI was 1.88% and the Manitoba Hydro average rate increases for the same period was 2.09%.

	Manitoba CPI 00/01=100	%	MH Overall Rate Inc. 00/01=100	%
2000/01	100.00	2.50	100.00	0.00
2001/02	102.15	2.15	98.10	-1.90
2002/03	104.50	2.30	98.10	0.00
2003/04	105.48	0.94	97.39	-0.72
2004/05	108.27	2.65	102.26	5.00
2005/06	110.92	2.45	104.56	2.25
2006/07	113.09	1.95	106.92	2.25
2007/08	115.26	1.92	106.92	0.00
2008/09	117.81	2.21	112.26	5.00
2009/10	118.56	0.64	115.47	2.86
2010/11	119.78	1.03	118.75	2.84
2011/12	123.11	2.79	121.13	2.00
2012/13	125.12	1.63	126.46	4.40
2013/14*	127.34	1.78	130.88	3.50

*forecast for fiscal 2013/14


Man CPI & MH Rate Increases 2000/01=100
135.00
130.00
125.00
120.00
115.00
110.00
105.00
100.00
95.00
90.00
Manitoba CPI
MH Overall Rate Inc.
2000/01
2002/03
2004/05
2006/07
2008/09
2010/11
2012/13

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 55

QUESTION:

Please explain and demonstrate how own price elasticity are incorporated into the load forecast by each customer class. If own price elasticities are not employed in the load forecast for any particular class, please explain why not.

RESPONSE:

Price elasticity is not a variable that is explicitly incorporated into Manitoba Hydro's load forecast. Please see Manitoba Hydro's response to PUB/MH I-256.

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 59

QUESTION:

Other than space heating and water heating, what are the next three appliances/applications of electricity that contribute the most to electricity usage in a household (excluding electric vehicles).

RESPONSE:

After space heating and water heating, the next three appliances/applications of electricity that contribute the most to electricity usage in a household (excluding electric vehicles) are refrigerators, lighting and clothes drying.

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 59

QUESTION:

For each of space heating, water heating and the three uses identified in response to part (a) what was the saturation and average use in 2009/10?

RESPONSE:

Based on the 2009 Residential Survey, the saturation rates and the average use of electric space heat, electric water heat and the three end-uses identified in CAC/MH I-041a are as follows:

End Use	% Saturation	Average Use kWh/Year
Electric Space Heat	35.3%	14,966
Electric Water Heat	45.9%	3,439
Refrigerators	99.7%	597
Lighting	100.0%	1,335
Electric Clothes Dryer	83.3%	933

Note that the saturation of secondary use refrigerators is 42.6%

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 60

QUESTION:

Please provide schedules that for each of these five Residential applications sets out the actual/forecast saturation and averages use for 2012/13 and for each subsequent five years (i.e., 2017/18, 2022/23, etc.) through to 2032/33. In the case of space and water heating please report existing and new houses separately.

RESPONSE:

The following chart shows the top five electric end-uses and average use across five year forecast periods.

Electric End-Use	2012/13	2017/18	2022/23	2027/28	2032/33
% Electric Heat Existing	36.3%	37.9%	38.6%	39.0%	39.3%
kW.h Average Use Electric Heat Portion Existing	14,996	15,024	15,057	15,083	15,105
% Electric Heat New	57.4%	56.2%	56.2%	56.2%	56.1%
kW.h Average Use Electric Heat Portion New	11,737	12,280	12,278	12,282	12,288
% Electric Water Existing	49.0%	54.1%	57.5%	60.1%	62.5%
kW.h Average Use Electric Water Existing	3,439	3,441	3,443	3,443	3,444
% Electric Water New	100.0%	100.0%	100.0%	100.0%	100.0%
kW.h Average Use Electric Water New	3,440	3,443	3,444	3,445	3,445
% Refrigerators	99.7%	99.7%	99.7%	99.7%	99.7%
kW.h Average Use Refrigerators	597	564	541	525	513
% Total Lighting	100.0%	100.0%	100.0%	100.0%	100.0%

kW.h Average Use Total Lighting	1,335	1,333	1,332	1,330	1,329
% Electric Clothes Dryer	83.3%	83.3%	83.3%	83.3%	83.3%
kW.h Average Use Electric Clothes Dryer	922	921	920	919	918

The above end uses are presented prior to the adjustment for codes and standards as outlined in Manitoba Hydro's response to CAC/MH I-042a.

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 61

QUESTION:

For the Residential Sector, please indicate what assumptions regarding new codes and standards were incorporated in the forecast average use values (per page 60) as opposed to which ones were addressed as an "adjustment" (per page 61).

RESPONSE:

Average use values for existing appliances were obtained using existing appliances as of the 2009 Residential Survey. Average use values for new appliances were obtained using only appliances in a newer age category, usually under 4 years old as of the 2009 Residential Survey. Electric space heat and electric water heat average use were differentiated not by appliance age, but by when the dwelling was built, with new dwellings classified as being built between 2005 and 2009. Therefore, the “new” average use values would incorporate all the codes and standards that are currently in place.

The final “adjustment” included the estimates of improvements in residential building codes, upcoming general residential lighting standards, codes for other residential equipment and commercial lighting codes that would not have been detected from the analysis of the 2009 survey data. Please refer to page 16 of the 2013 – 2016 Power Smart Plan – 15 year Supplementary Report included as Appendix E of the submission for more detail on energy efficiency codes and standards.

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 61

QUESTION:

What was the final adjustment impact of codes and standards?

RESPONSE:

The amount of codes and standards subtracted from the Residential forecast for future codes and standards is 22 GWh in 2013/14 growing to 255 GWh in 2022/23 and then to 288 GWh by 2027/28 and maintaining that level thereafter.

This does not include the estimated impact of Residential codes and standards that are captured through the average use of the new appliances in the Residential forecast, as described in the response to CAC/MH I-042a.

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 60

PREAMBLE: Chapter 4, page 20, Figure 4.10 shows a roughly 25% loss of the savings achieved to date by 2027/28 due to non-persistence of achieved savings.

QUESTION:

Please explain how the average use values used for different appliances are adjusted over time to account for the lack of persistence in DSM savings achieved to date.

RESPONSE:

The Residential forecast uses the average use of new equipment and appliances, which incorporate all DSM savings to date, including codes & standards. This average use is used for the entire forecast, so the savings are maintained.

For the purpose of the Residential forecast, codes and standards are maintained into the future and these persisting savings continue to be subtracted.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2; Page No.: 3

QUESTION:

For purposes of the 35 year planning horizon, what was the assumed annual growth in total domestic energy and demand (before and after DSM) post 2032/33?

RESPONSE:

For the 2012 Electric Load Forecast, post 2032/33 the energy and demand was assumed to grow each year at the same rate as was forecast from 2031/32 to 2032/33, with annual energy and demand growth beyond 2032/33 being 458 GW.h and 84 MW per year. Under the 2012 Base DSM forecast, savings from DSM programs reduce post 2032/33 growth to an average of 434 GW.h and 79 MW per year.

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 62

QUESTION:

Please indicate the 10-year average percentages attributable to the Medium and Large classes' customer growth are and how they were calculated. In particular does the calculation capture the fact that existing customers are re-assigned to classes as their usage changes over time.

RESPONSE:

Over the past 10 years, GS Medium has been 5.2% of the GS Mass Market growth of customers. GS Large has been 1.2% of the GS Mass Market growth of customers.

The 10 year average percentage takes the historical growth of customers in the GS Mass Market classes and determines the percentage growth of each class in relation to the total growth of all classes. The historical information includes re-assignments of classes due to usage changes that have occurred over the past 10 years and therefore captures this change information. As the forecast uses the historical percentages, the forecast reflects a continuance of these changes.

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 62

QUESTION:

Please provide a schedule that sets out the calculation of the five-year average use value for each customer class.

RESPONSE:

GS Mass Market Large

	Custs	Weather Adj kW.h	kW.h/cust
2008/09	276	1,634,133,403	5,917,129
2009/10	286	1,696,588,601	5,932,128
2010/11	298	1,759,786,508	5,910,084
2011/12	301	1,733,152,084	5,761,043
2012/13	315	1,782,375,582	5,652,234
5 Yr Avg			**5,834,523**

GS Mass Market Medium

	Custs	Weather Adj kW.h	kW.h/cust
2008/09	1,847	2,935,252,695	1,588,985
2009/10	1,888	2,955,134,863	1,565,568
2010/11	1,891	2,999,307,899	1,585,744
2011/12	1,909	2,984,614,165	1,563,649
2012/13	1,913	2,986,145,129	1,560,640
5 Yr Avg			**1,572,917**

GS Mass Market Small Demand

	Custs	Weather Adj kW.h	kW.h/cust
2008/09	11,341	1,883,460,661	166,072
2009/10	11,581	1,907,602,737	164,723
2010/11	11,840	1,938,463,945	163,722
2011/12	11,692	1,964,009,071	167,980
2012/13	11,889	2,010,085,476	169,078
5 Yr Avg			**166,315**

GS Mass Market Small Non-Demand

	Custs	Weather Adj kW.h	kW.h/cust
2008/09	50,676	1,564,045,888	30,864
2009/10	51,004	1,585,627,842	31,089

2010/11	51,164	1,608,675,821	31,442
2011/12	51,644	1,588,347,806	30,756
2012/13	51,859	1,619,261,580	31,224
5 Yr Avg			**31,075**

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 63

QUESTION:

What new codes and standards were assumed for purposes of the General Service Mass Market forecast and what was the assumed impact on average use?

RESPONSE:

Please refer to page 16 of the 2013 – 2016 Power Smart Plan – 15 Year Supplementary Report included as Appendix E of the submission for detail on the codes and standards included as an adjustment to the General Service Mass Market forecast. The forecast of the impact of these codes and standards were subtracted from forecast energy requirements for the General Service Mass Market. Reduced energy requirements due to codes and standards are not forecast by rate class, therefore no assumptions were made regarding impact on average use.

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 64

PREAMBLE: Chapter 4, page 20, Figure 4.10 shows a roughly 25% loss of the savings achieved to date by 2027/28 due to non-persistence of achieved savings.

QUESTION:

Please explain how the use of the five-year average accounts for the apparent loss in persistence of savings from DSM programs to date over the forecast period.

RESPONSE:

As Manitoba Hydro's 2013 Load Forecast uses the actual weather adjusted usage in 2012/13 fiscal year as the base year for forecasting purposes, any energy efficiency savings achieved to date will be reflected in the actual consumption and are assumed to persist over the forecast period. Manitoba Hydro uses the five-year weather-adjusted average use of General Service Mass Market customers to forecast the average use of new General Service Mass Market customers. As the five year average is based upon actual weather-adjusted consumption, it will reflect energy savings achieved to date and assume them to persist over the forecast period.

This approach is consistent with past Manitoba Hydro forecasts.

REFERENCE: Chapter 4: The Need for New Resources; Section: 4.2.2.1; Page No.: 20

QUESTION:

Please confirm that that the load forecast used assumes there are no new DSM programs introduced after 2027/28 and explain why.

RESPONSE:

The methodology used by Manitoba Hydro in developing its electricity forecast involves the assumption that there are no DSM programs in the future (including beyond 2027/28), however the forecast assumes the effects of future energy savings due to energy efficiency codes and standards.

REFERENCE: Appendix 4.1 Manitoba Hydro Generation Planning Criteria; Page No.: 1

QUESTION:

Please provide a copy of Manitoba Hydro Policy G195

RESPONSE:

Manitoba Hydro's approved policy on generation planning states:

Capacity Criterion

Manitoba Hydro will plan to carry a minimum reserve against breakdown of plant and increase in demand above forecast of 12% of the Manitoba forecast peak demand each year plus the reserve required by any export contract in effect at the time.

Energy Criterion

The corporation will plan to have adequate energy resources to supply the firm energy demand in the event that the lowest recorded coincident water supply conditions are repeated. Imports may be considered as dependable energy resources provided they utilize Firm Transmission Service and are sourced from either an Organized Power Market or a bilateral contract. The total quantity of energy considered as dependable energy from imports shall be limited to that which can be imported during the Off Peak Period, and shall not exceed the quantity of export contracts in effect at the time plus 10% of the Manitoba load.

Related Definitions:

Firm Transmission Service – full path transmission service of the highest priority that that may not be interrupted unless all lower priority levels of service have already been interrupted.

Organized Power Market – a centrally operated market which collects generation offers and dispatches generation to meet forecast loads, including exports from the market region, and which will provide physical energy to external market participants such as Manitoba Hydro on a non-discriminatory basis.

Off Peak Period – The following hours in a week during which the market load is typically lower than the weekly average load: Overnight- 7 days x 8 hours / day; Weekends- 2 days x 12 hours per day; Total = 80 hours per 168 hour week.

REFERENCE: Chapter 4: The Need for New Resources; Section: 4.3.1.1; Page No.: 36

QUESTION:

When was the last time that Manitoba Hydro reviewed the appropriateness of using a 12% reserve (as opposed to some other percentage)?

RESPONSE:

Please see Manitoba Hydro's response to CAC/MH I-051.

REFERENCE: Chapter 4: The Need for New Resources; Section: 4.3.1.1; Page No.: 36

QUESTION:

Please provide a copy of the most recent analysis undertaken by Manitoba Hydro supporting the use of the 12% reserve.

RESPONSE:

Please see Manitoba Hydro's response to CAC/MH I-051.

REFERENCE: Appendix 4.1 Manitoba Hydro Generation Planning Criteria; Page No.: 4

QUESTION:

Please provide a copy of the review of generation planning criteria completed in July 2012.

RESPONSE:

Attached is a copy of the subject report number PPD#12/05 titled Review of Generation Planning Criteria.

REVIEW OF GENERATION PLANNING CRITERIA

Resource Planning & Market Analysis Department
Power Planning Division

PREPARED BY:

K.J. HUNTER

APPROVED BY:

NOTED BY:

DATE: SEPTEMBER 12TH, 2013

REPORT: PPD #12/05

Manitoba Hydro

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Executive Summary

The Manitoba Hydro Generation Planning Criteria, as stated in Corporate Policy P195, were reviewed. The Generation Planning Criteria are intended to ensure what is generally referred to as resource adequacy for the province. Resource adequacy is the process of having sufficient supply to meet the aggregate electrical demand and energy requirements of the customers at virtually all times. The current form of the Manitoba Hydro planning criteria was established in the 1977 report titled Planning Criteria for Manitoba Hydro Firm Energy Supply. The details of the planning criteria requirements prior to 1977 are less clear, but appear to have included both a long standing capacity criterion as well as an energy criterion that may have been introduced sometime in the 1960's.

This review made the following four findings regarding the current criteria:

- In planning for the resource adequacy of a power system, there is a balance which must be struck between having resource adequacy under virtually all conditions and the net cost associated with having resources in excess of requirements. The existing generation planning criteria appear to have struck an appropriate balance in this regard.
- The form of existing generation planning criteria, which includes both a capacity criterion and an energy criterion, is appropriate for a predominately hydro region.
- Most of the power industry is moving towards a probabilistic approach to the study of resource adequacy in their region. Manitoba Hydro has done work in the area of probabilistic studies of its system, but none of the most recent studies have been specifically used or referenced in the recommendation for the capacity criterion. Further probabilistic analysis is required to update Manitoba Hydro's standard methodology, to provide documentation for the current criterion and to provide the basis for future updates to the capacity criterion.
- The existing energy criterion is open to interpretation in the area of how imports are considered as a source of dependable energy.

As a result of this review, the following four recommendations were made:

1. Recommendation on the Capacity Criterion

   It is recommended that the capacity criterion wording (shown below) not be modified at this time:

Capacity Criterion
Manitoba Hydro will plan to carry a minimum reserve against breakdown of plant and increase in demand above forecast of 12% of the Manitoba forecast peak demand each year plus the reserve required by any export contract in effect at the time. (E.M.C. 373.03)

2. Recommendation for Additional Probabilistic Studies

   It is recommended that Manitoba Hydro move towards using probabilistic studies to determine a suitable reserve margin for generation capacity in Manitoba.

3. Recommendation on the Energy Criterion

   It is recommended that the current energy criterion wording be modified to clarify the treatment of imports as dependable energy as stated below:

   Energy Criterion
   The corporation will plan to have adequate energy resources to supply the firm energy demand in the event that the lowest recorded coincident water supply conditions are repeated. Imports may be considered as dependable energy resources provided they utilize Firm Transmission Service and are sourced from either an Organized Power Market or a bilateral contract. The total quantity of energy considered as dependable energy from imports shall be limited to that which can be imported during the Off Peak Period, and shall not exceed the quantity of export contracts in effect at the time plus 10% of the Manitoba load.

4. Recommendation for Review of the Hydraulic Flow Record

   It is recommended that the risk tolerance inherent in the flow record be reviewed every 5 to 10 years.

1. Introduction

The purpose of Manitoba Hydro as stated in the Manitoba Hydro Act is "to provide for the continuance of a supply of power adequate for the needs of the province, and to engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power."

In the power industry, the process of ensuring an adequate or sufficient supply of power is referred to as resource adequacy analysis. Resource adequacy means having sufficient supply to meet aggregate electrical demand and energy requirements of the customers at virtually all times. Key drivers of physical risk of inadequate supply are extreme weather and its impact on short term load, unexpected load growth, unplanned (forced) outages of generation and transmission elements and for systems with a significant component of hydro resources - drought.

Having an insufficient supply of power to meet the current demand is likely to cause some sort of blackout – referred to as a loss of load event. Resource adequacy analysis involves the study of the probability of the occurrence of loss of load events. In planning for the resource adequacy of a power system, there is a balance which must be struck between having resource adequacy under virtually all conditions and the net cost associated with having resources in excess of requirements. Providing additional resources that may be required only under very infrequent conditions is expensive and leads to the question as to whether Manitoba Hydro is "engaging in and to promoting economy and efficiency" in building such resources. As noted in comments made on the Manitoba Hydro system in 1979, "It is theoretically impossible and practically too expensive to design a system that would have sufficient capacity under a combination of all conceivable adverse conditions. The capacity criterion that defines the size of the required capacity reserve reflects therefore, explicitly or implicitly, a policy regarding the probability of being able to meet peak demand[1]."

The degree of conservatism in generation planning so to be able to withstand very low probability physical events is a fundamental issue with regard to ensuring adequate supply for the needs of the province.

- [1] Main Characteristics of the Manitoba Hydro System in 1970 and Comments on Planning Criteria Used by Manitoba Hydro, by R. L. Walker and Partners Ltd., March 1, 1979, page 22.

1.1. Purpose of Generation Planning Criteria

The goal of utility resource planning is to ensure adequate supply to meet the load at least cost while meeting environmental and socioeconomic requirements. The overall resource planning process can be broken down into four steps as outlined in the Figure I below.

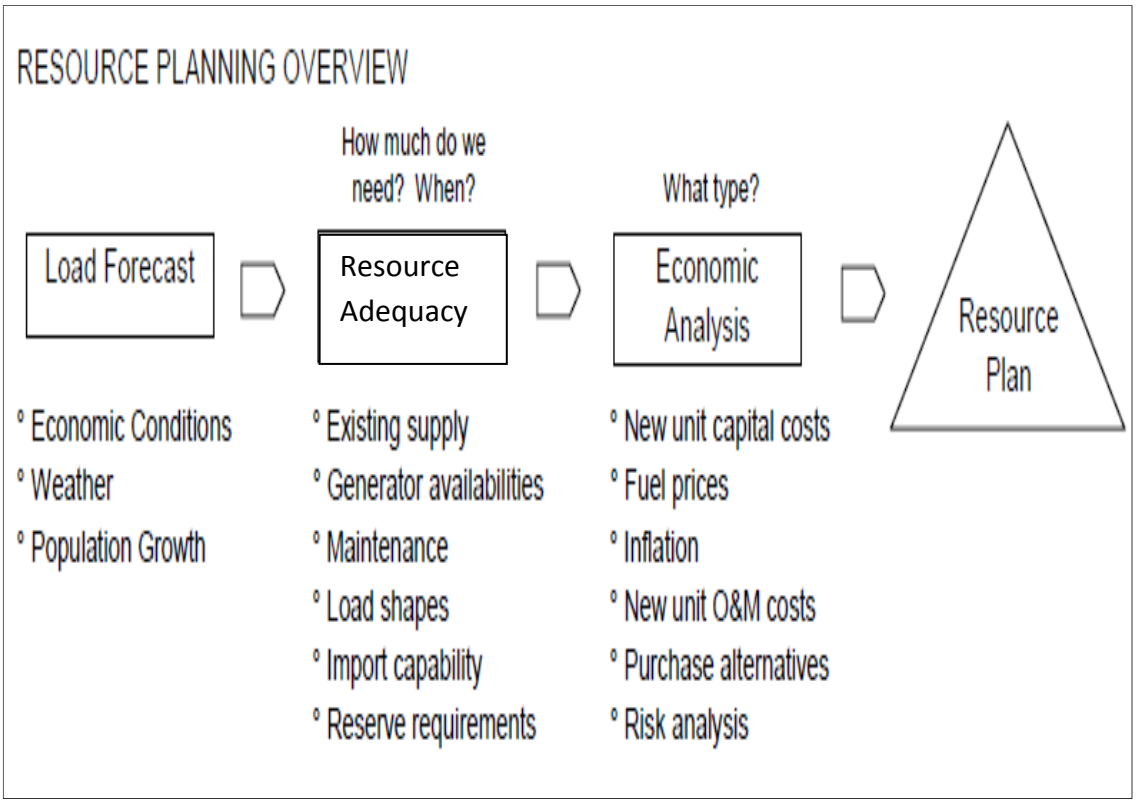


Figure I: Resource Planning Overview

It is important to note than in Figure I, the reliability (specifically – resource adequacy) analysis and economic analysis are separate steps. The goal of the resource adequacy analysis step is to determine the total quantity of resources required to meet the demand, including the timing of any additions. Only physical generation and load parameters are considered in the resource adequacy analysis step. Economic parameters (the capital and operating costs of the generation resources) are not considered in this step. Hence the output of the resource adequacy analysis step can determine what quantity of resources is required to meet the load, but not whether any particular mix of generation resources are an economically optimum way to meet the load.

The economic analysis step focuses comparing the total costs (both operating and capital) of potential resource development alternatives in order to determine the lowest cost development alternative. Typically, some sort of production costing tool is used to

determine the variable operating costs to meet the load over the planning horizon, and then fixed costs resulting from capital investment decisions are added on to determine the total cost of each development sequence studied. Having a particular resource development sequence meet the resource adequacy requirements does not in any way imply it would be an economically optimum development sequence. The economic analysis process is separate and independent from the resource adequacy analysis process and is not the focus of this review.

1.2. Form of Generation Planning Criteria Requirements

The mission of the North American Electric Reliability Corporation's (NERC) is to ensure the reliability of the North American bulk power system. However, there is no NERC standard which specifies generation planning / resource adequacy requirements which all North American load serving utilities must meet. As NERC noted in its 2004 Resource and Transmission Adequacy Recommendations report[2], "factors vary from region to region or system to system, a complete standardization of resource adequacy criteria methodologies may be difficult to achieve."

The 2004 NERC report went on to explain that:

> "Achieving reliability in the bulk electric systems requires, among other things, that the amount of generating capacity resources exceed customer demands by some amount. That amount (expressed as a percent of peak demand is termed a reserve margin and when expressed as a percent of generating capacity is termed capacity margin) must be sufficient to cover planned maintenance and unplanned or forced outages of generating equipment, deratings in the capability of demand-side and supply-side resources, system effects due to reasonably anticipated variations in weather, variations in customer demands or forecast demand uncertainty, delays in the construction of generating capacity, and other system operating requirements. In areas where the majority of supply-side resources are energy-constrained (such as the hydro-dominated US Pacific Northwest), achieving reliability may also require that the energy available to the area is, at least, equal to the customer demand and some reserve requirement during a certain critical design period for the constrained resources."

The amount that the accredited generation capacity resources exceed the median forecast peak load, expressed as a percent of the median forecast peak load is called the planning

[2] See Resource and Transmission Adequacy Recommendations, prepared by the Resource and Transmission Adequacy Task Force of the North American Electric Reliability Council (NERC), June 15, 2004, at page 10.

reserve margin or PRM[3]. The PRM is intended to be sufficient to cover reasonable combinations of outages, deratings, and forecast demand uncertainty as noted above.

For a predominately thermal system, which is a capacity limited system, a requirement to have sufficient spare generation capacity to meet the specified planning reserve margin is sufficient to ensure resource adequacy. For a predominately hydro system, such as Manitoba Hydro's, meeting the specified planning reserve margin is necessary, but is not sufficient to ensure resource adequacy. Predominately hydro systems are said to be energy constrained or energy limited. In other words, under a severe drought, they could run out of energy (water), even though there is sufficient generation capacity installed to meet the load. Therefore, as noted by NERC, predominately hydro systems also need an energy criterion to ensure that the energy available to the region is, at least, equal to the customer demand during a certain critical design period (drought) for the energy constrained resources. As explained in the next section, Manitoba Hydro has both a capacity requirement to carry what amounts to a planning reserve margin, as well as an energy criterion.

1.3. Current Generation Planning Criteria Requirements

The planning criteria that currently guide the Manitoba Hydro generation planning process are stated in Corporate Policy P195, *Generation Planning* and are as follows:

Capacity Criterion
Manitoba Hydro will plan to carry a minimum reserve against breakdown of plant and increase in demand above forecast of 12% of the Manitoba forecast peak demand each year plus the reserve required by any export contract in effect at the time. (E.M.C. 373.03)

Energy Resource Planning
The corporation will plan to have adequate energy resources to supply the firm energy demand in the event that the lowest recorded coincident river flow conditions are repeated. Planning studies, to meet the firm energy demand, may include up to a maximum of 10% of the energy demand in Manitoba to be supplied from the energy reserves on interconnected utilities, provided an energy purchase contract is or will be in effect during the time being studied. (E.M.C. 177.05)

[3] See NERC Standard Number: BAL–502–RFC–02 Planning Resource Adequacy Analysis, Assessment and Documentation, as approved in the US by FERC Order No. 747 Issued March 17, 2011.

1.4. Evolution of the Current Planning Criteria Requirements

The current form of the Manitoba Hydro planning criteria was established in the 1977 report titled Planning Criteria for Manitoba Hydro Firm Energy Supply,[4] which is referred to as the 1977 Report. The details of the planning criteria requirements prior to 1977 are less clear, but appear to have included both a long standing capacity criteria as well as an energy criterion that may have been introduced sometime in the 1960's.

The 1977 Report noted that "Prior to 1976 the policy regarding capacity reserve was to plan a reserve of at least 12% of the installed capacity". A capacity criterion in the form of a 12% reserve margin appears to have been in use as far back as 1962[5], and was likely based on industry practices in use in that era. The energy criterion that appears to have existed prior to 1974[6] was a requirement that the firm energy demand be met with available resources, excluding all imports, in the event of a repeat of the lowest recorded coincident river inflow conditions.

The 1977 Report was a result of a desire to review the reserve requirement, particularly in light of a major new interconnection planned at that time. The primary outcome of the 1977 Report was a change in the way the 12% reserve margin was applied, from 12% of installed to capacity (a capacity margin) to be based on 12% of peak demand (a planning reserve margin). This change was to keep with current industry practice – as all planning reserve margins calculations today are done of the basis of peak demand rather than installed capacity.

A major concern in the 1977 Report was to what degree imports should be used to serve Manitoba load, as imports were not considered as dependable energy prior to 1974. The 1977 Report specifically asked "How dependant on out-of-province energy sources can we afford to become?" The 1977 Report discussed that counting increased imports available from larger interconnections "increases the probability of requiring out-of-province energy support to supply Manitoba firm load. As it is Manitoba Hydro's responsibility to provide for the continuance of a supply of power adequate for the needs of the province we should be cautious about designing a system which would become increasingly dependent on out-of-province sources to supply our firm load commitments."

[4] See Planning Criteria for Manitoba Hydro Firm Energy Supply, System Planning Division Report 77-35, July 1977.
[5] See Manitoba System Development Interim Report No. 1 - Method of Analysis, Manitoba Hydro System Planning Department, May, 1962, p.2 "with the requirement of 12% spare capacity".
[6] See memo dated 1985 01 09 from W.A. Derry to W.J Tishinski with the subject Review of Corporate Policy Regarding Capacity and Energy Reserve Criteria

A conclusion of the 1977 Report was that "under the lowest coincident recorded river flows, planning of energy resources should not include any more than 10% of the annual energy demand to be imported from non-firm out-of province sources".

The 1977 Report recommended the following energy design criterion:
a) The system energy supply must equal or exceed the system demand in the event of a repeat of the lowest coincident historic river flows on the system.
b) The energy supply under condition (a) can be met by a combination of the following resources;

i.) The dependable energy generatable at all Manitoba Hydro facilities, plus;
ii.) The thermal generation, plus;
iii.) Any Firm Energy Purchases from out-of-province sources, plus;
iv.) Any Non-Firm Energy Commitments from out-of-province sources provided the quantity does not exceed 10% of the annual energy demand.

As a result of the 1977 Report, the planning criteria that were adopted were:

Capacity Criterion:
In the period 1976 to 1992, the Corporation will carry a reserve against breakdown of plant and increase in demand above forecast of 12% of the forecast peak demand each year. (Board 457–76–5)

Energy Criterion:
Under the conditions of the lowest coincident historic river flows, planning of energy resources will not include more than 10% of the annual energy demand to be imported from non-firm out-of-province sources. (Board 472–77–5)

In 1985, there was a review of the planning criteria and updated criteria were adopted with some minor wording changes[7]. References to the period 1976 to 1992 were dropped – as the 1992 date related to an expected date when all hydro in Manitoba would have been already developed – which was clearly unrealistic by 1985. References in the energy criterion to "not include more than 10% of the annual energy demand to be from non-firm out-of-province sources" were removed and replaced by the phrase "Planning studies, to meet the firm energy demand, may include up to a maximum of 10% of the energy demand in Manitoba to be supplied from the energy reserves on interconnected utilities, provided an energy purchase contract is or will be in effect during the time being studied."

[7] See memo dated 1985 01 09 from W.A. Derry to W.J Tishinski with the subject Review of Corporate Policy Regarding Capacity and Energy Reserve Criteria

As part of the 2001 Corporate Strategic Plan process, a review of the Planning and Operating Criteria for Bulk Generation and Transmission was undertaken as a joint effort between the Power Supply and Transmission and Distribution Business Units. Several phases of review were envisioned when the review was initiated. However, only Phase I of the review was completed in February 2003. The output of the Phase I review was a three page report which listed current generation and transmission planning criteria- and no changes to the generation planning criteria came about as a result of the Phase I review. The generation planning criteria, as they existed in 2012, were last modified in 1985 and are not significantly different than that developed in 1977.

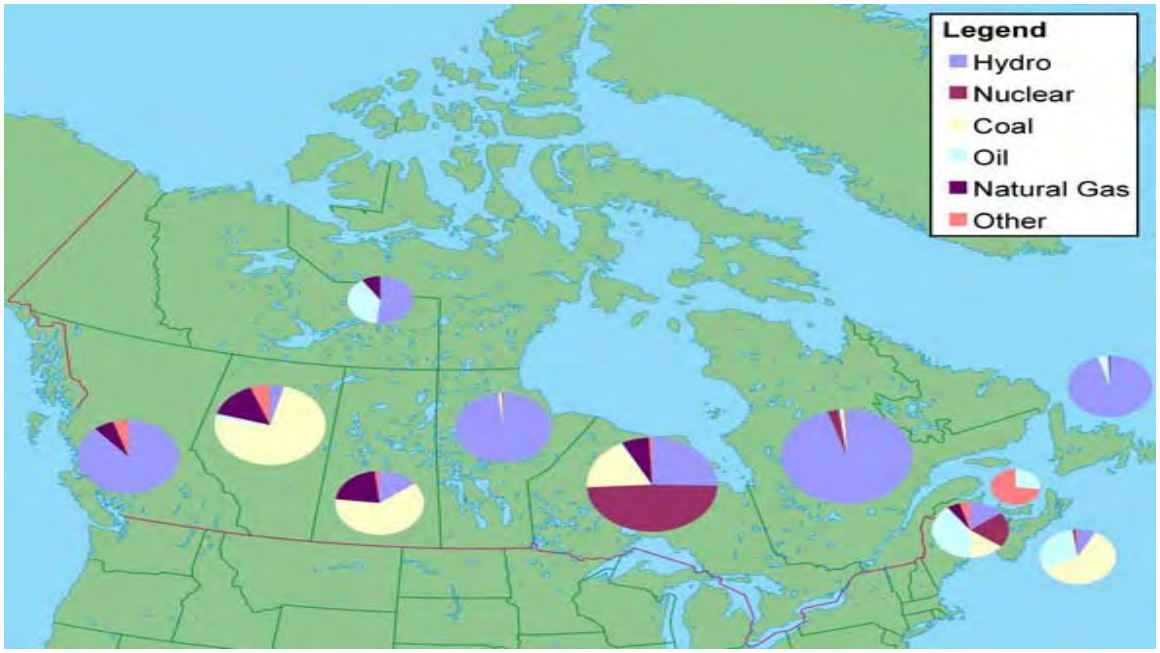
1.5. Unique Planning Characteristics of the Manitoba Hydro System

Electrical power systems tend to have their own unique characteristics as they were built to utilize locally available primary energy resources (hydro, coal, gas, nuclear) with a transmission system reflecting local geography, generation and load.

The unique characteristics of Manitoba Hydro's system are:

1.5.1. High Reliance on Hydro Generation

A greater proportion of Manitoba's electricity supply comes from hydro than any other province in Canada, or any state in the US.



Source: http://www.neb.gc.ca/clf-nsi/rnrgynfmtn/prcng/lctrct/cndnndstry-eng.html

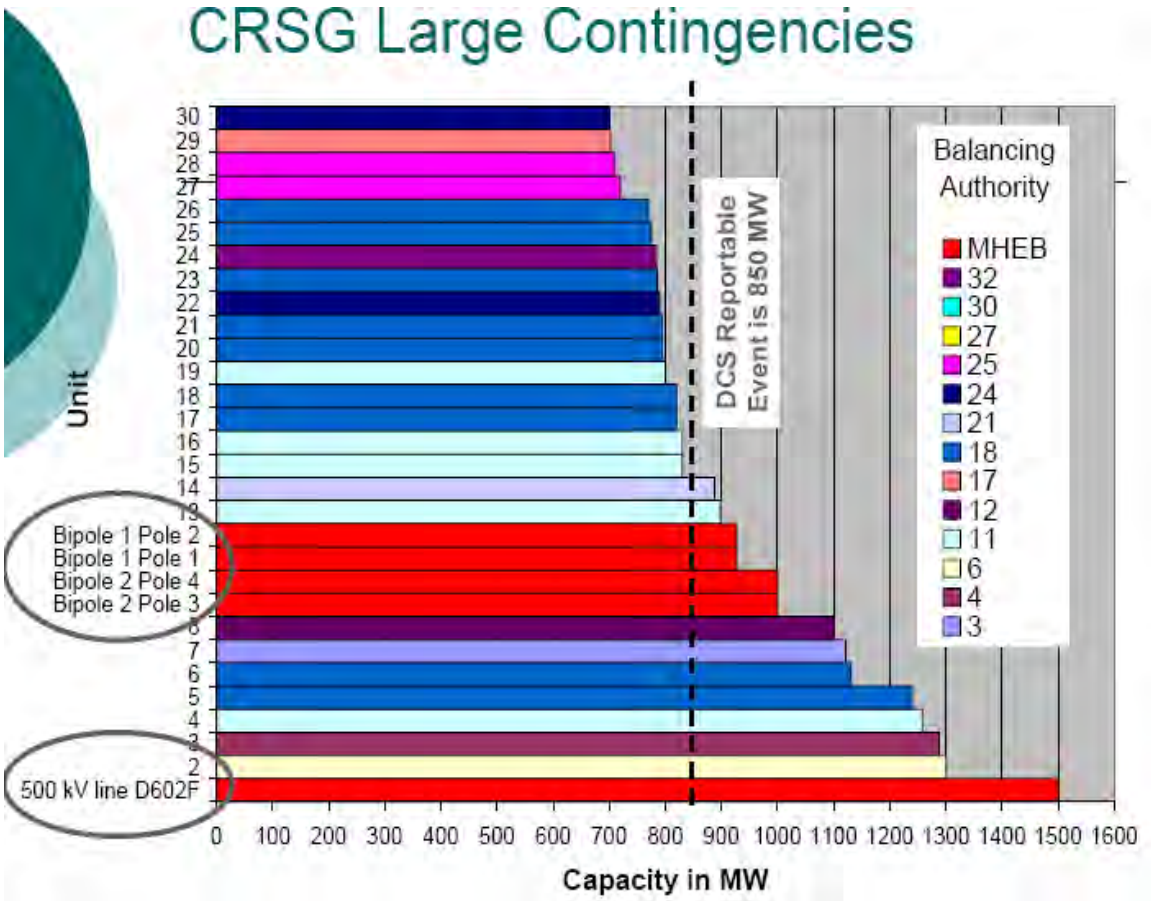
While hydro generation is a flexible and low cost resource, it is vulnerable to drought. Under a severe drought, Manitoba's hydro generation drops to about 70% of the long-term median generation. This drop in hydro generation is about 2.8 times the similar variability of either Hydro Quebec or BC Hydro. Both BC and Quebec have significantly larger reservoirs to absorb flow variations – Hydro Quebec's reservoir storage, expressed in months is about 2.3 times that of Manitoba Hydro, while BC Hydro's storage is 1.5 times that of Manitoba Hydro. Slightly offsetting this greater variability is that Manitoba Hydro's hydraulic flow record of nearly 100 years is longer than that of either BC Hydro or Hydro Quebec who both have a somewhat shorter flow record of around 70 years in length.

Hydro dominated systems in general tend to be energy limited – that is they will run out of energy (water) in a drought before they run out of capacity to meet peak loads. In contrast, the predominately thermal systems in the US have no energy limitations (assuming that natural gas and coal supplies do not run out), and there primary limitation is capacity – the ability to meet loads on a peak day. There is a natural synergy between hydro and thermal systems– provided there is sufficient transmission capacity to deliver excess hydro capacity and energy to loads in the thermal region – and for the hydro system to import energy during low demand periods.

1.5.2. High Reliance on HVDC and 500 kV Interconnection

Manitoba Hydro's system is heavily reliant upon five large transmission elements – the four HVDC poles (two poles at 930 MW and two poles at 1000 MW) and the Forbes-Dorsey 500 kV transmission line at 1500 MW. The Forbes-Dorsey 500 kV line is the largest single contingency in the Midwest ISO[8]. In fact, five of the twelve largest contingencies in the Midwest ISO are located within or originate within Manitoba. Also – all of these contingencies are transmission contingencies – which contrast sharply with almost all other major contingencies in the Midwest ISO which are generation contingencies. The high cost of building redundant transmission over the large distances within the province has resulted in the Manitoba Hydro transmission system not having the same level of redundancy as other Midwest transmission systems located in more populous regions. Hence Manitoba Hydro is reliant upon calling on contingency reserves for the loss of these major transmission elements.

[8] As noted in the 2008 STATE OF THE MARKET REPORT FOR THE MIDWEST ISO, by Potomac Economics, undated text version, Footnote 32 on page 154.



1.5.3. Significant Electric Heating Load in a Harsh Winter

Manitoba and Quebec consume the most electricity per capita within Canada, 20.7 and 21.9 MWh per person per year respectively[9]. One of the drivers of the high per capita consumption in Quebec and Manitoba are the cold winters combined with the high proportion of electric heat in those provinces[10]. Even homes with natural gas heat are affected by the loss of electric supply as gas furnaces generally don't work either without electric power, although it more feasible to run these from backup generators. Hence loss or restriction of the electricity supply is particular concern in a Manitoba winter where loss of heating can become a life safety issue.

[9] See http://www.fcpp.org/main/publication_detail.php?PubID=607â€ %20class=

[10] See http://www.sst.gc.ca/default.asp?lang=En&n=CB51D3B8-1&offset=4&toc=show#_edn3

2. North American Resource Adequacy Requirements

2.1. NERC Resource Adequacy Requirements

As previously noted, there is no NERC standard which specifies generation planning / resource adequacy requirements which all North American load serving utilities must meet. This apparent gap in the NERC reliability standards is a result of individual US states having jurisdiction over the siting and need for new generation, rather than the federal US government. There are simply too many states (and provinces) to come to an agreement on a specific national reserve margin requirement. Instead of a national or international standard, NERC depended on each region's or regional entities' determination of an appropriate level of generation or resource adequacy for that region's or member's system. In some cases, state commissions or provincial agencies may also dictate certain generation reliability or resource adequacy requirements – although such provincial requirements do not exist in Manitoba.

While there may be no national NERC standard for resource adequacy, the 2004 Resource and Transmission Adequacy Recommendations report[11] found that nine of the ten NERC regional reliability councils used a probabilistic approach to study resource adequacy in their region, with eight of the ten basing their reserve margin requirement on a probabilistic approach. Probabilistic methods use performance characteristics of the electric system components and other factors to predict the likelihood that the customer peak demand and electrical energy requirements will be served over some specified period. Probabilistic methods take into account the possibility of forced generating unit outages, adverse weather, variations in customer demand, and other factors. These techniques, referred to as Loss of Load Expectation (LOLE) or Loss or Load Probability (LOLP) studies, involve complex calculations and rely on computer simulations to determine a minimum planning reserve margin which much be carried to meet a specified reliability target.

NERC does prepare a Long Term Reliability Assessment (LTRA) annually to review the adequacy of the bulk electric system in the United States and Canada over a ten-year period. The report projects electricity supply and demand, evaluates transmission system adequacy, and discusses key issues and trends that could affect reliability. NERC is now obligated to prepare the assessments in accordance with the US Energy Policy Act of 2005, in which the United States Congress directed NERC to conduct periodic assessments of the reliability and resource adequacy of the bulk power system of North America.

[11] See Resource and Transmission Adequacy Recommendations, prepared by the Resource and Transmission Adequacy Task Force of the North American Electric Reliability Council (NERC), June 15, 2004 at page 12.

Manitoba is a separate assessment area in the NERC LTRA reports. The data the NERC relies on for the LTRA comes from Manitoba Hydro. While NERC has no legal authority to order improvements in Manitoba or elsewhere as a result of any deficiencies found in resource adequacy assessments, the LTRA reports are publically available and NERC would rely on public and peer pressure for corrective action, if required.

2.2.NERC Survey of Regional Requirements

A 2008 NERC Survey[12] by the Resources Issues Subcommittee/ Reliability Metric Working Group found that six of the eight regional entities[13] had a resource adequacy assessment methodology using probabilistic models, and the other two were heading in that general direction. A summary of the 2008 NERC Survey is provided in Table One.

The 2008 NERC Survey results again made it clear that the resource adequacy assessment methodologies were quite diverse among the regions and sub-regions—often the reason for the differences is that each assessment is tailored to the resource mix and transmission configuration of the regional or sub-regional footprint. The 2008 NERC Survey did confirm that while there is no single national standard, the use of probabilistic models to study regional resource adequacy was widespread. The six NERC regional entities using probabilistic models, generally had some probabilistic metric expressed as either as a Loss of Load Probability or Loss of Load Expectation of less than one event in 10 years (or 0.1 day per year). In commenting on the results of the survey, the NERC Resources Issues Subcommittee noted that the following are minimum expectations of a resource adequacy assessment:

- The assessment should determine whether the resources of the bulk power system achieve a certain level of reliability
- The common expression of an acceptable level of reliability is 0.1 day per year LOLE, which is often translated to a planning or capacity reserve margin.
- The studies are over long-term planning horizons of 1-10 years to allow sufficient time to construct new power system infrastructure.

A more detailed description of the resource adequacy analysis requirements in the several NERC regional entities and sub-regions within those areas is proved in Appendix B. The ReliabilityFirst Corporation (RFC) regional entity is ahead of the others in that it has a NERC and FERC approved standard BAL–502–RFC–02 for “Planning Resource Adequacy Analysis, Assessment and Documentation” which is provided in Appendix C.

[12] See Minutes of the July 29–30, 2008 NERC Resources Issues Subcommittee meeting.

[13] With the transformation of NERC from the North American Reliability Council to the North American Reliability Corporation in 2007, the ten former NERC regions became eight regional entities, with NERC continuing in an oversight role. The Midwest Reliability Organization (MRO) is NERC the regional entity to which Manitoba Hydro is a member of.

Regional Entity/ Planning Coordinators	Model Description			Resource Adequacy Measure			Stochastic Parameters	Planning Horizon
	Name of Model	Prob/ Determ	Time Step	Probabilistic Metric/Target	Planng Reserve Margin			
					Probabilistic	Deterministic		
ERCOT 1/	ProSym	Prob	Hourly	Hourly LOLP ≤ 1 event in 10 years 2/	12.5%		load & wind forecast; gen outages	
FRCC 7 of 13 Planning Coordinators responded	TIGER	Prob	Hourly	Peak day LOLP ≤ 0.1 days/year	20% IOUs 15% others		thermal forced outages	10 yrs
MRO 5 of 5 Planning Coordinators responded	GE MARS MARELI PROMOD IV	Prob	Hourly	No study yet; LOLE standard	15%/10%, 18%, 13-15% (EUE)	12% firm hydro (Manitoba)	thermal forced outages	10 yrs 20 yrs
NPCC 3 of 6 Planning Coordinators responded	GE MARS GRIDVIEW	Prob	Hourly	Annual LOLE ≤ 0.1 days/year	No NPCC PRM; 18%-1 subarea	PRM > loss of largest unit; 20%	load forecast; gen outages	5 yrs up to 10 yrs
RFC 3 of 4 Planning Coordinators responded	Various GE MARS MARELI PRISM	Prob	Hourly	LOLE ≤ 1 occurrence in 10 years	ranges from 12% up to 18%		load forecast; gen outages	10 yrs
SERC 12 of 19 Planning Coordinators responded	RELY GE MARS	Various		No regional criterion	cap margins 10% - 15%		load forecast; gen outages	10 yrs 15 yrs 20 yrs
SPP 1/	?	Prob	Hourly	In progress; 1999 Study LOLE of .1	12% cap mrg: 9% if hydro 75%		load, energy-limited res, FOR?	3-5 years out
WECC 17 of 36 Planning Coordinators responded	SAM	Deter	seasonal peak hour	No probabilistic criterion		building block; 12% - 17%	NA	10 yrs

1/ Both ERCOT and SPP are Regional Entities and the only Planning Coordinators for their areas
2/ Global Energy Decisions was the contractor to perform the LOLP studies

Regional Entity/ Planning Coordinators	TREATMENT OF RESOURCES:				ASSESSSMENT INCLUDES:			IMPLEMENTATION:	
	Energy-Limited		DSM Resources		Firm Imports/ Exports	Tie Benefits	Emergency Operating Procedures	Regulators	Market
	Hydro Derated	Wind: Historical On-Peak	Subtract from Load	DR as Resource					
ERCOT	NA	8.7% ELCC	EE--Yes	LAAR--Yes	No	1/2 of 1106 mw asyn cap	Yes		✓
FRCC 7 of 13 Planning Coordinators responded	NA	NA	varies by utility	varies by utility	Yes	No	Yes	✓	
MRO 5 of 5 Planning Coordinators responded	Yes	0 & 20% CF or historical	4 subareas	1 subarea	Yes	Mostly No, 1 Yes	No	✓	✓
NPCC 3 of 6 Planning Coordinators responded	No Yes	No NPCC standard yet historical	varies by subarea	varies by subarea	Yes	Yes, on subarea basis	Yes	✓	✓
RFC 3 of 4 Planning Coordinators responded	GADS derate, if any	historical or 13% or 20% CF	Yes		Yes	No, only on CBM basis	No	✓	✓
SERC 12 of 19 Planning Coordinators responded	varies by entity	not much wind currently	varies by entity	varies by entity	Yes	No	No	Mostly	Some
SPP	Yes	Yes	Yes		Yes	Up to path limits	No		✓ SPP Compl
WECC 17 of 36 Planning Coordinators responded	Yes	Yes	Yes		by subarea	by subarea	No	✓	

2.3.MISO Module E Resource Adequacy Requirements

While the Midwest Independent System Operator (MISO) is a regional transmission organization and power market operator rather than a NERC regional entity, it does have resource adequacy requirements to help ensure proper functioning of the power markets. Module E – Resource Adequacy of MISO's energy market tariff outlines mandatory requirements to be met by MISO itself, market participants and serving load within the MISO market footprint. The requirements of Module E were intended to recognize and be complimentary to the resource adequacy mechanisms of the US states and the NERC regional entities within the MISO market footprint.

Note that Manitoba Hydro is an external MISO market participant and has a coordination agreement with MISO in relation to its transmission tariff. Manitoba Hydro's load is not served under the MISO tariff, and hence the MISO Module E requirements pertaining to load serving entities do not apply to Manitoba Hydro. Manitoba Hydro does have to meet the Module E requirements as they pertain to capacity sales made to entities within MISO.

The MISO resource adequacy requirements[14] include the methodology for determining the amount of capacity needed to achieve a Loss of Load Expectation (LOLE) of 1-day-in-10-years. The result is expressed as a planning reserve margin (PRM) in excess of the forecasted system coincident peak load. The MISO resource adequacy requirements are designed to meet the same 1-day-in-10-years loss of load expectation standard used by two of the three NERC regional entities within the MISO market footprint– the ReliabilityFirst Corporation and the Midwest Reliability Organization. The third regional entity – SERC (formerly the South Eastern Reliability Council) does not have a resource adequacy standard, with planning studies having been conducted by its member utilities.

MISO conducts annual loss of load expectation studies[15]. For 2012, the MISO LOLE study found that "in accordance with the MISO Tariff, the reliability objective of a Loss of Load Expectation (LOLE) study is to determine a minimum planning reserve margin that would result in the MISO system experiencing a less than one day loss of load event every ten years. The MISO analysis shows that the system would achieve this reliability level when the amount of installed capacity available is 1.167 times that of the MISO system coincident peak." Load serving entities must then own or purchase capacity based on their load, the calculated planning reserve margin and a number of adjustments, including adjustments to account for non-coincident peaks across the large MISO market

[14] See Module E of the MISO Energy Market Tariff or the Brattle report titled Midwest ISO's Resource Adequacy Construct, dated January 19, 2010.
[15] See for example Planning Year 2012 LOLE Study Report, by the Loss of Load Expectation Working Group (LOLEWG) and the Regulatory and Economic Studies Department (RES), dated November 18, 2011.

footprint. Included in the MISO LOLE study is a cross reference table to demonstrate compliance with the regional resource adequacy standard BAL–502–RFC–02 for Planning Resource Adequacy Analysis, Assessment and Documentation.

While the MISO Module E resource adequacy requirements do not apply to the Manitoba Hydro load, Manitoba Hydro does sell surplus capacity into the MISO market which export customers use to meet their Module E requirements. There may be a presumption of reciprocity – in that MISO or the Manitoba Hydro export customers may expect that Manitoba Hydro meets some sort of comparable resource adequacy requirement in order be able to sell surplus capacity into the MISO market.

3. Generation Planning Criteria Review Findings:

3.1. Existing Criteria Appears to have Struck an Appropriate Balance

As noted in the Introduction, in planning for the resource adequacy of a power system, there is a balance which must be struck between having resource adequacy under virtually all conditions and the net cost associated with having resources in excess of requirements. The existing generation planning criteria appear to have struck an appropriate balance in this regard.

A survey of current planning reserve margins across North America, outlined in Appendix D, shows that Manitoba Hydro's current capacity criterion requiring a 12% capacity reserve margin is similar or slightly lower than surveyed regions, which were in the 12-17% planning reserve margin range. Hence Manitoba Hydro's existing capacity criterion is not more stringent (and potentially more costly) than in other regions. Manitoba Hydro's energy criterion is also comparable to other predominately hydro regions such as British Columbia, Quebec and the US Pacific Northwest, in that they are all based around some defined critical flow period (the "lowest recorded coincident river flow conditions").

While Manitoba Hydro's capacity criterion is not stricter than other regions, it has been adequate in that Manitoba Hydro has experienced no known loss of load events due to lack of generation in the last 30 years. However, it should be noted that since the completion of Kettle in the early 1970's – Manitoba Hydro has generally had significant surpluses above the Manitoba load and it is not clear if this reliability is directly a result of the planning criteria or a result of having quantities of surplus capacity and energy for export that were well in excess of that specified in the planning criteria. Such surpluses were the result of the economies of scale involved in the development of large hydro resources.

Manitoba Hydro's system continues to evolve as the Manitoba load grows. New resource and new interconnections are added from time to time. The High Voltage Direct Transmission (HVDC) system, which did not exist prior to 1970, now carries on the order of 70% of the Manitoba Hydro's generation. Until the completion of Limestone in 1992, there was also significant spare capacity on the HVDC system. Manitoba Hydro's hydraulic flow record that forms the basis for its planning analysis as well as the identification of the critical flow period is subject to change. For example climate change and upstream withdrawals could alter the average and/ or dependable hydro energy available. Hence Manitoba Hydro's system will continue to evolve and there needs to be r periodic review of the generation planning criteria and hydraulic flow record.

The length of the hydraulic flow record, which is nearly 100 years, represents an implied tolerance of Manitoba Hydro to a severe drought. The return period for the worst drought on the record, the critical flow period, is at least the 100 year length of the hydraulic flow record. Annual inflows lower than that on the hydraulic flow record and hence beyond that designed for, will occur, but at a frequency believed to be greater than once in 100 years. The severity of the design drought or critical flow period is a policy decision, and it is noted that Manitoba Hydro' critical flow period methodology is comparable to other regions with significant hydro generation. Going forward, it would be appropriate to review the hydraulic flow record, including its length and whether it is evolving due to issues such as withdrawals or climate change, and determine if the design tolerance to a severe drought is consistent with current corporate or provincial tolerances to such an event.

3.2. Form of Existing Criteria is Appropriate

Manitoba Hydro's generation planning criteria has both a capacity criterion and an energy criterion, which is appropriate for a predominately hydro region. All power systems need some margin of generation capacity above peak load as a provision for generator outages, load forecast and other uncertainties. In addition, as discussed in Section 1.2, predominately hydro systems also need an energy criterion to ensure that the energy available to the region is, at least, equal to the customer demand during a certain critical design period (drought) for the energy constrained resources.

As well, a review of resource adequacy criteria [See Appendix B] in other predominantly hydro regions showed that they do not have criteria other than capacity and energy criteria.

It is our conclusion that a form of planning criteria which includes a capacity criterion and an energy criterion is both necessary and sufficient for Manitoba Hydro.

3.3. Need for Updated Reference to Probabilistic Studies

As discussed in Section 2, most of the industry is moving towards a probabilistic approach of the study of resource adequacy in their region. Manitoba Hydro has done work in the area of probabilistic studies of its system but none of the recent studies was specifically used or referenced in the development of the current capacity criterion. The most recent probabilistic studies of the Manitoba Hydro system that have been done have not been conclusive, but rather served to highlight the challenges of the probabilistic modeling of a predominately hydro system.

Further probabilistic analysis is required to update Manitoba Hydro's standard methodology, to provide documentation for the current or an updated capacity criterion, and to meet ongoing NERC expectations under their Long Term Reliability Assessment (LTRA) process. Such probabilistic analysis should be consistent with current NERC directions for resource adequacy analysis such as the NERC regional standard No. BAL–502–RFC–02 for "Planning Resource Adequacy Analysis, Assessment and Documentation".

3.4. Interpretation Uncertainty

The existing planning criteria are brief, and are open to interpretation with respect to imports and transmission limitations:

3.4.1. Imports

The 1977 report discussed the key issue of "How dependant on out-of-province energy sources can we afford to become?" A conclusion of the 1977 Report was that "under the lowest coincident recorded river flows, planning of energy resources should not include any more than 10% of the annual energy demand to be imported from non-firm out-of province sources". The 1977 report clearly differentiated between firm energy purchases – which were permitted to be considered as dependable energy without any apparent limit, and non-firm energy commitments – which were limited to 10% of the annual energy demand.

As a result of the 1985 review, references to non-firm out-of-province sources were dropped and replaced with the current wording that dependable energy "may include up to a maximum of 10% of the energy demand in Manitoba to be supplied from the energy

reserves on interconnected utilities provided an energy purchase contract is or will be in effect during the time being studied."

Since open access in power markets began with FERC Order 888 in 1996, and continuing with the start of the MidWest Independent System Operator (MISO) Day 2 Market in 2005, Manitoba Hydro's access to imports from the United States has improved and evolved. Today, generating units within the MISO market footprint are dispatched by MISO rather the individual utilities. Energy purchases are made through MISO on the Day Ahead and Real Time markets – although financial bilateral contracts may still be arranged directly with utility counterparties. Financial bilateral contracts are a price hedging mechanism which have no effect on the way MISO operates the system, and in fact can be entered into the transaction portal after they occur. Today, firm transmission service from the MISO market footprint is the key to having certainty on import transactions – rather than a utility counterparty to a financial bilateral contact.

The current energy criteria wording, its history, and power market changes over the last 15 years raise the following questions related to the consideration of imports as dependable energy:

- Should Manitoba Hydro differentiate between firm and non-firm imports? Are the terms firm and non-firm different from the terms contracted and non-contracted energy?
- Given the changes in the MISO market, what value from a resource adequacy perspective should be placed on a bilateral contract with a utility counterparty that does not dispatch its own generation? Do the MISO rules and market participation agreement and firm transmission service for imports replace bilateral contracts with a utility counterparty in an open market?
- How much energy is available from the MISO market, should Manitoba Hydro decide to rely upon it?
- How should potential imports from Ontario – an energy only market with non-firm transmission, and Saskatchewan– a bilateral only counterparty with no open market, be considered. Are these potential sources of imports different than the MISO market?

It is found that in consideration of power market changes, imports can be considered as dependable energy as follows:

- Imports of energy from a large power market whose resources are predominately thermal pose very little risk of curtailment due to lack of energy supply, provided the deliveries are scheduled on firm transmission service, the market rules provide for physical delivery, and the deliveries are scheduled in a period which does not coincide with the peak load in the power market.

- For regions where there is no organized market (i.e. Saskatchewan) imports of energy on firm transmission under the terms of a bilateral contract remain a potential source of dependable energy.
- Imports of energy from Ontario should not, at this time, be considered as dependable energy as the current Ontario market rules do not provide for firm transmission service out of Ontario, the Ontario market rules do not provide for physical delivery (the Ontario rules allow financial settlement in lieu of physical delivery), and in any event energy out of North Western Ontario is not assured in a drought as the sub-region is predominately hydro and its supply is correlated with Manitoba Hydro own hydro resources.

3.4.2. Transmission Limitations

Transmission limitations are not explicitly mentioned in the current generation planning criteria. Transmission limitations can affect resource adequacy in Manitoba through importation limitations or through potential HVDC outages.

Clearly, the physical transmission line limits on Manitoba Hydro's interconnections affects the maximum quantities of energy which can be imported. Transmission limits are generally expressed as firm transfer capabilities and the rights to schedule energy on the transmission interconnection. Additional transmission capability may be available on non-firm transmission, but this cannot be relied upon for planning purposes due to the uncertainty of its availability. Some statement as to how transmission interconnection limitations are to be considered in the planning process is desirable.

As noted in Section 1.1.2 Manitoba Hydro's system is heavily reliant upon large transmission elements including the HVDC system. The trend in resource adequacy analysis, as expressed in the regional resource adequacy standard provided in Appendix C is to include "transmission limitations that prevent the delivery of generation reserves" and to include "common mode outages that affect resource availability". Large outages of the HVDC system could be considered such common mode outages and thus Manitoba Hydro should be moving in the direction of including major transmission outages in its resource adequacy analysis.

3.4.3. Wind Generation

Wind generation, like thermal generation, is not specifically referenced within the existing planning criteria. However both types of resources are currently considered as a source of energy and/ or capacity for the Manitoba Hydro system. Utility scale wind

generation is still a relatively new type of resource, and methodologies for evaluating the contribution of wind generation to resource adequacy are still evolving[16].

A further consideration for wind turbine operation in Manitoba is low temperature operation. At the present time, commercially available utility scale wind turbines are shut down at -30°C to avoid mechanical failures as a result of low temperature operation. As Manitoba Hydro is winter peaking, the very extreme cold temperatures that cause low temperature wind turbine shut downs also tend to cause peak load conditions.

It is anticipated that the methodologies for evaluating the resource adequacy contribution of wind generation to power systems will continue to evolve. Therefore, no specific methodologies regarding the evaluation of wind generation can be included in the planning criteria at this time.

[16] For example, see Methods to Model and Calculate capacity Contributions of Variable Generation for Resource Adequacy Planning, issued by NERC, March 2011.

4. Recommended Changes to the Generation Planning Criteria:

The form of the current generation planning criteria which has both capacity and energy criteria is appropriate and sufficient for a predominately hydro utility, and both are required in any updated generation planning criteria.

4.1. Recommendation on the Capacity Criterion

It is recommended that the capacity criterion wording (shown below) not be modified at this time:

> **Capacity Criterion**
> *Manitoba Hydro will plan to carry a minimum reserve against breakdown of plant and increase in demand above forecast of 12% of the Manitoba forecast peak demand each year plus the reserve required by any export contract in effect at the time. (E.M.C. 373.03)*

4.1.1. Justification

As discussed in Section 3.1 the existing generation planning criteria appear to have struck an appropriate balance between having resource adequacy under virtually all conditions and not requiring excess resources.

4.2. Recommendation for Additional Probabilistic Studies

It is recommended that Manitoba Hydro move towards using probabilistic studies to determine a suitable reserve margin for generation capacity in Manitoba.

4.2.1. Justification

The direction in the industry is towards the use of probabilistic studies to determine required planning reserve margins. While Manitoba Hydro has done work in the area of probabilistic studies of its system, none of the recent studies was specifically used or referenced in the development of the current capacity criteria. Further probabilistic analysis is required to develop a standard methodology, to provide documentation for the current or an updated capacity criterion, and to meet ongoing NERC expectations under their Long Term Reliability Assessment (LTRA) process.

Probabilistic studies form a major part of what the industry refers to as resource adequacy assessments. The NERC Resources Issues Subcommittee noted that the following are minimum expectations of a resource adequacy assessment:

- The assessment should determine whether the resources of the bulk power system achieve a certain level of reliability
- The common expression of an acceptable level of reliability is 0.1 day per year LOLE, which is often translated to a planning or capacity reserve margin.
- The studies are over long-term planning horizons of 1-10 years to allow sufficient time to construct new power system infrastructure.

The current industry direction for resource adequacy analysis, such as stated in NERC regional Standard No. BAL–502–RFC–02 "Planning Resource Adequacy Analysis, Assessment and Documentation" is to include consideration of factors such as:

- Load forecast uncertainty and diversity.
- Resource characteristics including historic resource performance, outages, deratings, and retirements.
- Transmission limitations that prevent the delivery of generation reserves.
- Transmission limitations into the study area (interconnections).
- Availability and deliverability of fuel.
- Common mode outages that affect resource availability.
- Environmental or regulatory restrictions of resource availability.
- Impacts of extreme weather/drought conditions that affect unit availability.

Some of these factors are new areas of consideration, and it will take some time for Manitoba Hydro to refine its expertise and develop standard methodologies and assumptions for performing such probabilistic studies. For example, water conditions and HVDC outages could be considered in the analysis.

NERC, through public reporting mechanisms such as the Long Term Reliability Assessment (LTRA) does annually review the adequacy of the bulk electric system in the United States and Canada over the upcoming ten-year period. Manitoba is a separate assessment area in the NERC LTRA reports. The data the NERC relies on for the LTRA comes from Manitoba Hydro. While NERC has no legal authority to order improvements in Manitoba or elsewhere as a result of any deficiencies found in resource adequacy assessments, the LTRA reports are publically available and NERC would rely on public and peer pressure for corrective action, if required.

4.3. Recommendation on the Energy Criterion

It is recommended that the current energy criterion wording be modified to clarify the treatment of imports as dependable energy as stated below:

> **Energy Criterion**
> The corporation will plan to have adequate energy resources to supply the firm energy demand in the event that the lowest recorded coincident water supply conditions are repeated. Imports may be considered as dependable energy resources provided they utilize Firm Transmission Service and are sourced from either an Organized Power Market or a bilateral contract. The total quantity of energy considered as dependable energy from imports shall be limited to that which can be imported during the Off Peak Period, and shall not exceed the quantity of export contracts in effect at the time plus 10% of the Manitoba load.

4.3.1. Justification

As discussed in section 3.4.1, the wording for the current energy criteria raises several questions related to the consideration of imports as dependable energy. The revised wording is intended to address these issues as follows:

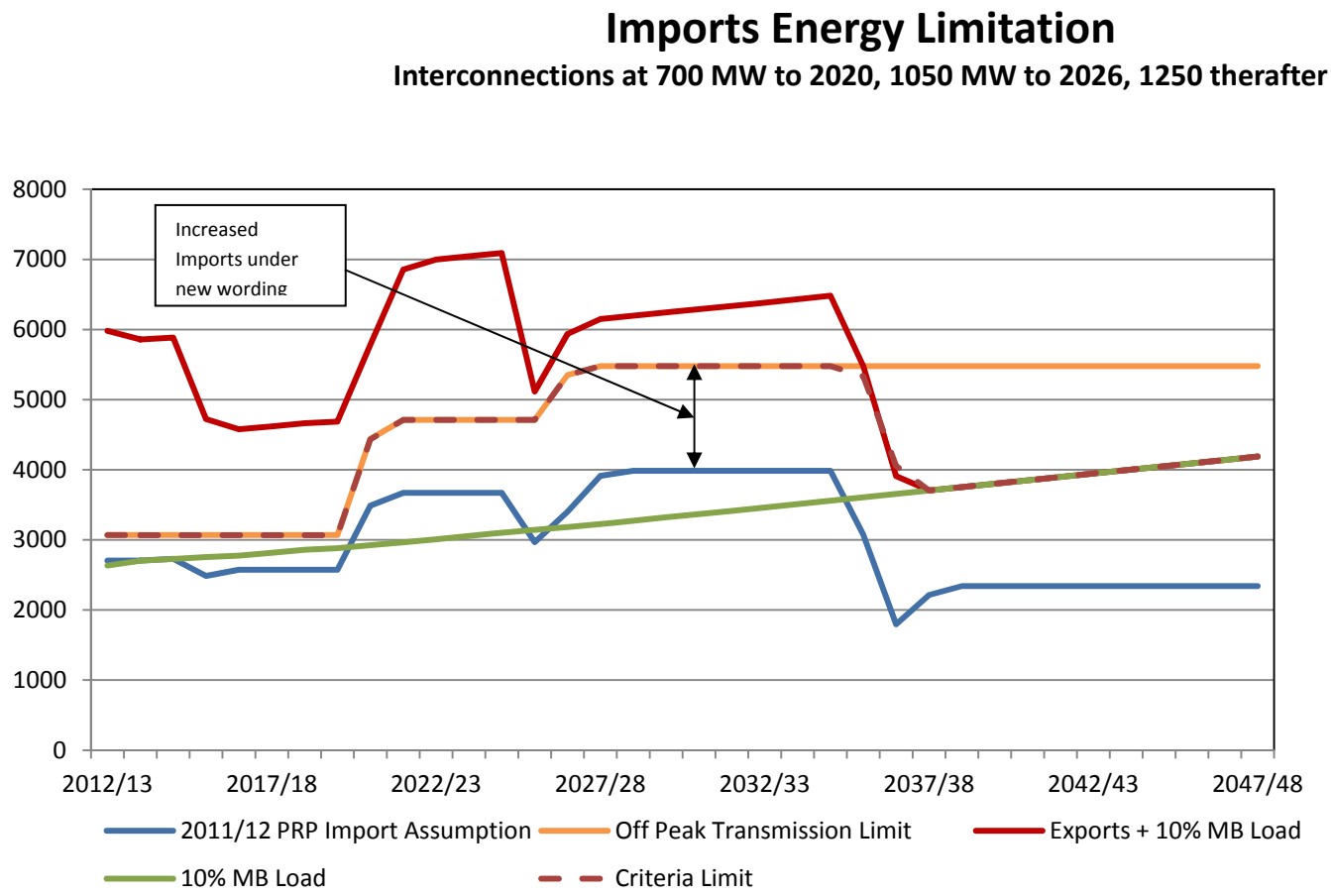
- The wording clarifies that Firm Transmission Service is required for imports considered as dependable energy to minimize the risk of curtailment of imports due to transmission system issues. Firm Transmission Service is defined in Appendix A as full path (source to sink) transmission service that may not be interrupted except during force majeure type conditions when continued delivery of power is not possible. This requirement for the highest grade of transmission service also places a physical limit on the import capacity.
- The wording explicitly permits imports sourced from an Organized Power Market or from a bilateral counterparty where there is no organized market (i.e. Saskatchewan). An Organized Power Market is defined in Appendix A as a centrally operated market which collects generation offers and dispatches generation to meet forecast loads, including exports from the market region, and which will provide physical energy to external market participants such as Manitoba Hydro on a non-discriminatory basis. In Organized Power Markets, it is the market operator rather than the generation owner which dispatches the generation and therefore controls exports and the planning criteria needs to reflect this reality. For the US interface, under the MISO market rules, the MISO market participation agreement and firm transmission service have replaced the bilateral control from the perspective of assurance of delivery. MISO market rules are non-discriminatory in that they do not put exports at a lower priority

than load served within the market. Bilateral contracts with counterparties within the MISO market can be very useful to determine in advance the price for energy - but cannot provide for delivery as that is determined by the market operator.

- The wording places two limits on the maximum quantity of import energy which can be considered as dependable energy. First, the total quantity of energy considered as dependable energy from imports shall be limited to that which can be imported during the off peak period (80 hours per week). The 80 hours per week is equal to the 8 overnight hour each day of the week (7x8 = 56 hours), plus 12 hours each weekend (2x12). The weekend hours specifically exclude the 4 peak hours each weekend day (2x4) that are deemed to be capacity delivery hours. The MISO market is a very large predominately thermal system, with over 134,900 MW of generation in the market footprint to serve a peak market load of 103,975 MW[17]. Provided there is firm transmission service, there is ample surplus generation in the off peak hours to provide an assured supply of energy from the MISO market.
- The second limitation on imports is the maximum quantity of import energy considered as dependable energy shall not exceed the quantity of export contracts in effect at the time plus 10% of the Manitoba load. This wording is intended to be generally consistent with the 1977 Report that observed a break point on a flow duration curve for which imports above 10% of the Manitoba load required disproportionally more flow years in which imports would be required. The 1977 Report raised the question "How dependent on out-of-province energy sources can we afford to become", and answered the question with a limitation on non-firm energy commitments from out of province sources not exceeding 10% of the annual energy demand. The concept that is being observed with this wording is that not more than 10% of the Manitoba load would be served by imports under dependable energy conditions.

The implications of these changes are detailed in the Imports Energy Limitation Graph. The current planning criteria limitations are shown in the 2011/12 Power Resource Plan Import Assumptions line. The recommended changes to the import assumptions are shown in the Criteria Limit line. The Off Peak Transmission Limit becomes the until a around 2035. The recommended changes provide for increased imports as new interconnections are built in the future. This provides an economic benefit to Manitoba Hydro with an estimated present value on the order of $100 million – significant but not likely to have a major impact on selected planning sequences.

[17] Source – MISO Corporate Fact Sheet – September 2011



4.4. Recommendation for Review of the Hydraulic Flow Record

It is recommended that the risk tolerance inherent in the flow record be reviewed every 5 to 10 years.

4.4.1. Justification

The hydraulic flow record is a fundamental data input into the planning process for a predominately hydro utility. The length of the hydraulic flow record, which is nearly 100 years, represents an implied tolerance of Manitoba Hydro to a sever drought. The return period for the worst drought on the record, the critical flow period, is at least the 100 year length of the hydraulic flow record. Droughts beyond that on the hydraulic flow record and beyond that designed for, will occur, but at a frequency believed to be greater than once in 100 years.

The severity of the design drought or critical flow period is a policy decision, and it is noted that Manitoba Hydro's critical flow period methodology is comparable to other regions with significant hydro generation. A regular review of this implied risk tolerance is appropriate given its significance to the adequacy of the electrical supply for the province. Further, there are evolving issues such as climate change, upstream withdrawals, and regulatory changes which also have the potential to impact the planning process or results of the planning process and should be reviewed on a period basis.

Appendix A - Definitions:

Dependable Energy– the maximum energy that the Manitoba Hydro system can produce (Manitoba generation plus imports) during the lowest (critical) flow period. The dependable energy available to Manitoba Hydro is the sum of dependable energy from hydro generation (within Manitoba), imports, thermal generation (within Manitoba), and wind generation (within Manitoba) [Reference Presentation to the Manitoba Public Utilities Board Supply and Demand Planning by Joanne Flynn, Division Manager, Power Planning on May 31 and June 1, 2010.]

Dependable Energy from Hydro Generation– the maximum energy available from hydraulic resources in the Manitoba Hydro system during the worst drought in the flow history. Record begins in 1912. The critical drought period occurs from 1939 through 1941, and is based on hydraulic generation from system inflows during the critical period and generation from water held in reservoir storage. The dependable energy from hydro generation includes existing and planned hydro generating stations and water management facilities of Lake Winnipeg Regulation, the Churchill River Diversion, and Cedar Lake. Inflows modified to reflect forecast upstream withdrawals. [[Reference Presentation to the Manitoba Public Utilities Board Supply and Demand Planning by Joanne Flynn, Division Manager, Power Planning on May 31 and June 1, 2010.]

Dependable Exports – Exports that are sourced from Manitoba Hydro's dependable energy resources and include the associated product of accreditable capacity, and have duration of greater than six months. [Reference PUB–MH–22 dated 2007–02–13]

Opportunity Exports – Exports that are sourced from Manitoba Hydro's non-dependable energy resources or from purchases and may include short-term firm or non-firm sales, spot market and monthly energy sales. The quantities sold are dependent on Manitoba Hydro's surplus capacity and energy situation in the short term based on knowledge of prevailing water flow conditions. Opportunity exports are generally less than six months in duration, as the availability of opportunity energy cannot usually be forecasted beyond that time frame. [Reference PUB–MH–22 dated 2007–02–13]

Firm Transmission Service – full path transmission service of the highest priority that that may not be interrupted unless all lower priority levels of service have already been interrupted

Organized Power Market – a centrally operated market which collects generation offers and dispatches generation to meet forecast loads, including exports from the market region, and which will provide physical energy to external market participants such as Manitoba Hydro on a non-discriminatory basis

Off Peak Period – The following hours in a week during which the market load is typically lower than the weekly average load: Overnight- 7 days x 8 hours / day; Weekends- 2 days x 12 hours per day; Total = 80 hours per 168 hour week.

Appendix B

Details of NERC Regional Planning Reserve Study Requirements:

1. MAPP/ MRO Requirements

A regional resource adequacy requirement applicable to Manitoba Hydro and other members of the Mid Continent Area Power Pool (MAPP) existed up until the dissolution of the MAPP Generation Reserve Sharing Pool (GRSP) at the end of 2009. The MAPP Reserve Capacity Obligation (RCO) effectively required that thermally based utilities carry what equated to a 15% planning reserve margin, but calculated for compliance purposes based on actual load rather than future load projections. For hydro utilities, only a 10% reserve margin was required. A 2002 MAPP Generation Reserve Sharing Observation and Recommendations report[18] footnoted that "the predominantly hydro entities of WAPA and Manitoba Hydro only have to carry a 10% reserve because hydro generation has much lower forced outage rates. The long term equivalent forced outage rate for Manitoba Hydro units is about 1.06% while steam units such as coal will usually be in the 5-7% range within MAPP. In some areas of the country forced outage rates are even higher for steam units." The MAPP RCO did not include an energy criterion for predominately hydro as discussed in the 2004 NERC Resource and Transmission Adequacy Recommendations report.

The 2002 MAPP report noted that while there was no national NERC resource adequacy standard, there was "however, across the regions a well-established industry practice has developed for measuring the adequacy of planning reserves. The practice is to limit the probability of customer outages resulting from blackouts to large portions of the Bulk Electric System to 1 day in 10 years. Detailed, expensive and time-consuming loss of load probability ("LOLP") studies are employed to determine the amount of planning reserves that are needed to meet a LOLP of 1 day in 10 years. The studies are based on historical unit outage statistics, load forecasts and other forward-looking projections. LOLP studies can be used to derive a reserve margin, which provides a cushion of generation capacity to meet forced outages and fluctuations in customer demand."

MAPP's 15% planning reserve margin for thermal systems was established in 1974 based on probabilistic study, with the lower 10% reserve margin for hydro based on the observation that hydro unit forced outage rate is much lower than thermal units[19]. A series of subsequent probabilistic studies in 1981, 1991, 1994 and 2003 recommended

[18] See MAPP GENERATION RESERVE SHARING OBSERVATIONS & RECOMMENDATIONS, A Report by the MAPP Reserve Task Force, January 8, 2002.
[19] See Manitoba Hydro presentation titled "2009 MAPP LOLE Study", dated February 11, 2010 by B. Bagen.

continuation of the 15% reserve margin for MAPP thermally-dominant systems. Significantly, the Manitoba Hydro system was not modeled in any published MAPP probabilistic study until 2008. In the 2008 and 2009 MAPP regional probabilistic studies, the Manitoba load was not studied as a separate zone and no specific conclusions from that work with regards to Manitoba planning reserve margins could be drawn.

Over the last seven years, MAPP has evolved into a new NERC regional entity called the Midwest Reliability Organization (MRO). With the dissolution of the MAPP Generation Reserve Sharing Pool (GRSP) at the end of 2009, there were no longer any resource adequacy requirements applicable to Manitoba Hydro. Attempts by the MRO to develop a Planned Resource Adequacy Assessment standard number RES–501–MRO–02 failed and the MRO Standards Committee suspended work on the project in 2010.

2. Northeast Power Coordinating Council Guidelines

The Northeast Power Coordinating Council, Inc. (NPCC) is an organization responsible for promoting and improving the reliability of the international, interconnected bulk power system in Northeastern North America, including Quebec, Ontario, the Maritime Provinces, the New England states as well as the state of New York.

The NPCC has a requirements that each planning coordinator (or sub region) submit a resource adequacy assessment in accordance with Appendix D – Guidelines for Area Review of Resource Adequacy[20]. The guidelines require each planning coordinator to undertake a five year resource adequacy assessment at least every three years, with a provision for interim reviews. The purpose of the resource adequacy assessment to determine if the existing and proposed resources can meet the forecast load in accordance with the resource adequacy design criteria. Unless otherwise specified by a state, the criteria is that the risk of disconnecting firm load due to resource deficiencies shall be, on average, not more than one day in ten years. Compliance is to be evaluated probabilistically using Loss of Load Expectation (LOLE) studies.

2.1. Ontario Analysis

Ontario's Independent Electricity System Operator (IESO) annual prepares an assessment of resource adequacy for the Ontario in accordance with the Reliability Assessment Program established by the Northeast Power Coordinating Council (NPCC). The Ontario system is studied using the GE MARS probabilistic reliability

[20] See Appendix D – Guidelines for Area Review of Resource Adequacy in the NPCC Reliability Reference Directory for the Design and Operation of the Bulk Power System.

analysis software. The main finding was "The 2011 Interim Review[21] reports that Ontario will be able to meet the NPCC resource adequacy criterion that requires a Loss of Load Expectation (LOLE) of no more than 0.1 days/year for all years from 2012 to 2014. For all forecast years under median demand growth, NPCC criterion is achieved using only existing, contract committed, and government directed resources, without the need for Emergency Operating Procedures (EOPs), additional resources, or imports."

2.2. Quebec Analysis

Hydro Quebec Distribution prepares annual resource reviews in accordance with the NPCC guidelines – the most recent being the "2011 Québec Balancing Authority Area Comprehensive Review of Resource Adequacy" which is publically available on the NPCC website. The Hydro Quebec system is modeled in GE MARS using six internal zones and with interconnections to five adjacent regions. Key findings from that report:

- To assess its energy reliability Hydro-Québec has developed an energy criterion stating that sufficient resources should be available to go through a sequence of consecutive years of low water inflows totaling 64 TWh or a sequence of 4 years totaling 98 TWh, and having a 2 percent probability of occurrence. The use of operating measures and the hydro reservoirs should be managed accordingly. Reliability assessments based on this criterion are presented three times a year to the Québec Energy Board. Such documents can be found on the Régie de l'Énergie du Québec website.
- The 2011 Comprehensive Review shows that Québec area will be able to meet the NPCC resource adequacy criterion that requires a Loss of Load Expectation (LOLE) value of less than 0.1 days/year for all years from 2011/2012 to 2015/2016. In fact, in 2015/2016, winter peak period planned resources (45,401 MW) are above forecasted load (39,313 MW) by 6,088 MW.

2.3. Western Electricity Coordinating Council Requirements

The Western Electricity Coordinating Council (WECC) is the NERC regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection– the largest and most diverse of the eight NERC regions. This region is relevant as it includes the provinces of Alberta and British Columbia,

[21] See IESO 2011 Interim Review of Resource Adequacy Covering the Ontario Area for the period 2012 to 2014, dated October 19, 2011.

and all or part of fourteen TS stares including the hydro dominated Pacific Northwest region. The WECC region has some 36 sub regions which have their own planning coordinators. Given this degree of fracture, WECC is one of the two NERC regional entities which do not have some sort of standard for at least the study of resource adequacy. Instead, any resource adequacy requirements in WECC reside at the sub region level.

2.3.1. Alberta Requirements

The Alberta Electric System Operator (AESO) operates a competitive energy only electricity market. The AESO does publish on its website quarterly reviews of long term adequacy. Those metrics were developed in consultation with stakeholders and serve as key indicators monitoring the available long term supply of electricity in the province. However, after a 2008 review, the AESO took the position that the market will provide the proper level of resource adequacy in stating[22] "Targets for standard industry metrics like reserve margin and "loss of load probability" led to required levels of generation capacity being built. However, under an energy-only market model, like Alberta, the market determines the appropriate reserve margin; it determines the appropriate level of adequacy in the long term."

As a backstop to the market determining the appropriate level of reliability, the AESO does have a Two Year Probability of Supply Adequacy Shortfall Metric, which is a probabilistic assessment of encountering a supply shortfall over the next two years. The calculation estimates, on a probabilistic basis, how much load may go without supply over the next two year period. Based on extensive consultation with stakeholders, when this unserved energy exceeds 1,600 MWh in any two year period (equivalent to one hour 800 MW shortfall in each of the two years) the AESO may step into the market take undefined actions "to bridge the temporary supply adequacy gap without impacting investor confidence in the market."

The success of Alberta's reliance on the market to provide reliability is open for debate. On January 17, 2012, the AESO launched a level one energy emergency as all available power in Alberta was operating and forced demand reduction were possible[23]. Problems were also experienced in the summer of 2012 and 2013.

[22] See Long Term Adequacy Metrics, Threshold and Threshold Actions Recommendation Paper by the Alberta Electric System Operator, dated February 7, 2008.
[23] See Plants Down, Power Prices Up, The Calgary Herald, January 18, 2012.

2.3.2. British Columbia Requirements

Up until 2005, BC Hydro considered that historically, it was energy constrained, but that capacity requirements where now driving new resource acquisitions. To assure that there is adequate energy to meet its commitments; BC Hydro uses the driest water year in its historical record to define the firm (dependable) energy capability of its hydro resources. BC Hydro states that this practice is commonly found in large energy constrained hydro systems and is identical to the standard used by the Bonneville Power Administration hydro system located immediately south of BC in the US Pacific Northwest[24].

For capacity analysis, BC Hydro determines how much peak load can be served from its system based on a Loss of Load Probability (LOLP) methodology. This methodology assesses the probability that specified peak loads can be served from the dependable capacity1 that the system generation resources provide. When the probability of meeting the peak loads on particular days is summed over the year, it results in a Loss of Load Expectation (LOLE). BC Hydro plans its system to meet the annual LOLE criterion of no more than 1 day in ten years (or 0.1 days per year). Generation resources that supply dependable capacity include those owned by BC Hydro, IPP supply under contract to BC Hydro and dependable capacity available from external markets.

BC Hydro's studies in 2006 found that a planning reserve margin of 14% as calculated using LOLP analysis was sufficient to meet the criterion is 1-day-in-10-years loss of load[25].

2.3.3. US Pacific Northwest Requirements

The US Pacific Northwest is defined in the Northwest Power Act of 1980 to include the states Idaho, Montana, Oregon and Washington – which encompasses the US portion of the large Columbia River drainage basin and its large hydro resources. The Northwest Power and Conservation Council has a legal mandate to develop a regional power plan for the Pacific Northwest.

In 2005, the Pacific Northwest Power and Conservation Council created the Pacific Northwest Resource Adequacy Forum to "establish a resource adequacy framework

[24] See presentation for Resource Options Workshop #2– Planning Criteria for the BC Hydro 2005 Integrated Electricity Plan, dated March 09, 2005.
[25] See APPENDIX F10– Calculation of Capacity Planning Reserves of BC Hydro's 2008 Long Term Acquisition Plan regulatory filing.

for the Pacific Northwest to provide a clear, consistent, and unambiguous means of answering the question of whether the region has adequate deliverable resources to meet its load reliably and to develop an effective implementation framework."

The Forum developed a Resource Adequacy Standard for the Pacific Northwest region which was officially adopted in 2008.The standard was intended to be a provides a minimum threshold that serves as an early warning should resource development fall dangerously short of requirements. It did not mandate compliance or imply any enforcement mechanisms.

The 2008 Resource Adequacy Standard for the Pacific Northwest was based on the use of probabilistic analysis to determine loss of load probabilities while considering variation in hydroelectric generation, load, forced outages and wind generation. The regions tolerance for a significant power supply shortage was assumed to be 5 percent - that is, the region would tolerate a significant power shortage no more than once in 20 years. The level of resources required to meet this Loss of Load Probability (LOLP) was then translated into equivalent planning reserve margins – one for winter energy, one for winter capacity and one for summer capacity. The 2008 standard determined that planning reserve margins in the range of 23 to 24 percent were required to meet the reliability targets.

Initial experience found that while the 2008 standard was sound, it could be improved and simplified. A review was initiated and A New Resource Adequacy Standard for the Pacific Northwest was adopted in late 2011. The 2011 version of the resource adequacy standard retained the LOLP methodology and also retained the regions tolerance for a power shortage of less than 5% or no more than once in 20 years. The new standard did change the LOLP calculations to be based on an annual analysis (as opposed to seasonal analyses done in the 2008 standard).

The Pacific Northwest Power and Conservation Council uses probabilistic computer model specifically developed for the predominately hydro region to assess resource adequacy. The GENESYS computer model performs a detailed hourly chronological simulation of the Northwest's resources, including the hydroelectric system, over many different possible future conditions. Each future's operation is simulated using different assumptions for uncertain variables, namely; 1) river flows (which affect the amount of water for hydroelectric generation), 2) temperature (which affects demand for electricity), 3) forced outage conditions for generating resources and 4) wind generation. The GENESYS probabilistic capabilities with regard to consideration of the long term hydraulic record of the Pacific Northwest appear more advanced than in other regions.

2.4. ReliabilityFirst Corporation Requirements

ReliabilityFirst Corporation (RFC) is the NERC regional entity responsible for preserve and enhance electric service reliability and security for thirteen states of the US northeast, including Ohio, Indiana, Pennsylvania, Michigan and part of Wisconsin and Illinois. This footprint includes the eastern half of the MISO market region.

The ReliabilityFirst region is unique in North America with regards to resource adequacy requirements in that as of March 2011, it has a FERC approved regional Planning Resource Adequacy Analysis, Assessment and Documentation standard[26].
The RFC resource adequacy assessment standard is to establish common criteria, based on "one day in ten year" Loss of Load Expectation principles, for the analysis, assessment and documentation of Resource Adequacy for Load in the RFC region. The standard is for a methodology to assess resource adequacy, rather than a requirement to build generation to meet some target.

Under the RFC resource adequacy assessment standard, the planning coordinator for each sub-region is to annually calculate for the upcoming year a planning reserve margin that will result in the sum of the probabilities for loss of load comparable to a "one day in 10 year" criterion. The assessment must also study or at least verify resource adequacy one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period. The assessment is to include documentation of the load forecast, load forecast uncertainty, contractual arrangements, resource characteristics (including modeling assumptions of intermittent such as wind and energy limited resources such as hydro), interconnections with adjacent systems, and impacts of extreme weather/drought conditions that affect unit availability. The documentation of the resource adequacy analysis is to be publicly posted.

The RFC standard number BAL–502–RFC–02 for Planning Resource Adequacy Analysis, Assessment and Documentation was approved by the US Federal Energy Regulatory Commission (FERC) as Order No Order No. 747 on March 17, 2011 [See Appendix C for details]. FERC was careful to note in the approval order that resource adequacy raises "complex jurisdictional concerns" which at times are at the "confluence of state-federal jurisdiction." FERC found that resource adequacy assessments are relevant to reliability and, further, that the reliability aspect of resource adequacy assessments does not preempt state action and jurisdiction in the area of resource adequacy. Hence the RFC resource adequacy assessment standard has threaded the needle of federal authority over grid reliability and the states' jurisdiction over matters

[26] See FERC Order No. 747 in Docket No. RM10-10-000 for NERC regional reliability standard BAL-502-RFC-02 for Planning Resource Adequacy Analysis, issued Issued March 17, 2011.

related to resource adequacy. FERC also acknowledged in Order No.747 that the one day in ten years criterion is a well-established and common criterion for assessing resource adequacy. The RFC standard could become a template for other NERC regional entities or for NERC itself to move forward on resource adequacy.

Appendix C:

NERC Regional Reliability Standard for "Planning Resource Adequacy Analysis, Assessment and Documentation" Standard No. BAL–502–RFC–02

Applicable Regional Entity: ReliabilityFirst Corporation (RFC) region

B. Requirements

R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall *[Violation Risk Factor: Medium]*:

R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for Loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 year" criterion).

R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the Loss of Load Probability.

R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median[2] forecast peak Net Internal Demand (planning reserve margin).

R1.2 Be performed or verified separately for each of the following planning years:

R1.2.1 Perform an analysis for Year One.

R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 though 10 year period.

R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

R1.3 Include the following subject matter and documentation of its use:

R1.3.1 Load forecast characteristics:

Median (50:50) forecast peak Load.

Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).

Load diversity.

Seasonal Load variations.

Daily demand modeling assumptions (firm, interruptible).

Contractual arrangements concerning curtailable/Interruptible Demand.

R1.3.2 Resource characteristics:

Historic resource performance and any projected changes

Seasonal resource ratings

Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area.

Resource planned outage schedules, deratings, and retirements.

Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration.

Criteria for including planned resource additions in the analysis

R1.3.3 Transmission limitations that prevent the delivery of generation reserves
R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis
R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.
R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

Availability and deliverability of fuel.
Common mode outages that affect resource availability
Environmental or regulatory restrictions of resource availability.
Any other demand (Load) response programs not included in R1.3.1.
Sensitivity to resource outage rates.
Impacts of extreme weather/drought conditions that affect unit availability.
Modeling assumptions for emergency operation procedures used to make reserves available.
Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area.

R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included
R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis
R1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis
R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis *[Violation Risk Factor: Lower]*.
R2.1 This documentation shall cover each of the years in Year One through ten.
R2.2 This documentation shall include the planning reserve margin calculated per requirement R1.1 for each of the three years in the analysis.
R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.

C. Measures

M1 Each Planning Coordinator shall possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1.
M2 Each Planning Coordinator shall possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2.

APPENDIX D

Survey of Current Planning Reserve Margins:

MISO:
"2.2 Planning Reserve Margin (PRM) Calculation: Using the generation, load and tie line capability representations in the model, simulations were run to determine the Loss of Load Expectation (LOLE) value for the planning year. Capacity adjustments were then put in place to alter the available capacity to ensure that the probabilities for loss of load within the MISO system over each integrated peak hour for the planning period summed 0.1 days/year. All external zones were modeled at that regions targeted planning reserve margin levels with adjustments made to account for MISO firm external designated resources. When capacity was appropriately adjusted in the MISO LOLE zone to bring the system to a 0.1 days/year LOLE value the ratio of capacity to coincident load in the MISO yielded a reserve margin of 14.4% of the 50/50 net internal demand forecast. However, since the GADS information input to the simulation reflects generator availability much higher than recently observed availabilities, the 14.4% was adjusted to 16.7%. Details of how this adjustment also affects the post-simulation calculations for PRMUCAP, are in Appendix B. The 16.7% value is the planning reserve margin as applied to the MISO system coincident peak. [Emphasis added]"

Source: MISO Planning Year 2012 LOLE Study Report, by the Loss of Load Expectation Working Group (LOLEWG) And Regulatory and Economic Studies Department (RES), November 2011.

Saskatchewan:
"So to ensure truly reliable service, we have a safety margin of between 15 and 20 percent - what we call our generation reserve capacity."

Source: Powering Saskatchewan's Future, SaskPower, May 2009

Quebec:
Table 5.1.1 Planned Resources to meet criteria under Base Case Demand Forecast shows a Required Reserve of 11.4% in 2014/15 and 12.2% in 2015/2016

Source: NPCC 2011 Québec Balancing Authority Area Comprehensive Review of Resource Adequacy, by Hydro-Québec Distribution, dated November 29, 2011.

British Columbia:
"BC Hydro determines how much peak load can be served from its system based on a Loss of Load Probability (LOLP) methodology. This methodology assesses the probability that specified peak loads can be served from the dependable capacity that the system generation resources provide. When the probability of meeting the peak loads on particular days is summed over the

year, it results in a Loss of Load Expectation (LOLE). BC Hydro plans its system to meet the annual LOLE criterion of no more than 1 day in ten years (or 0.1 days per year).

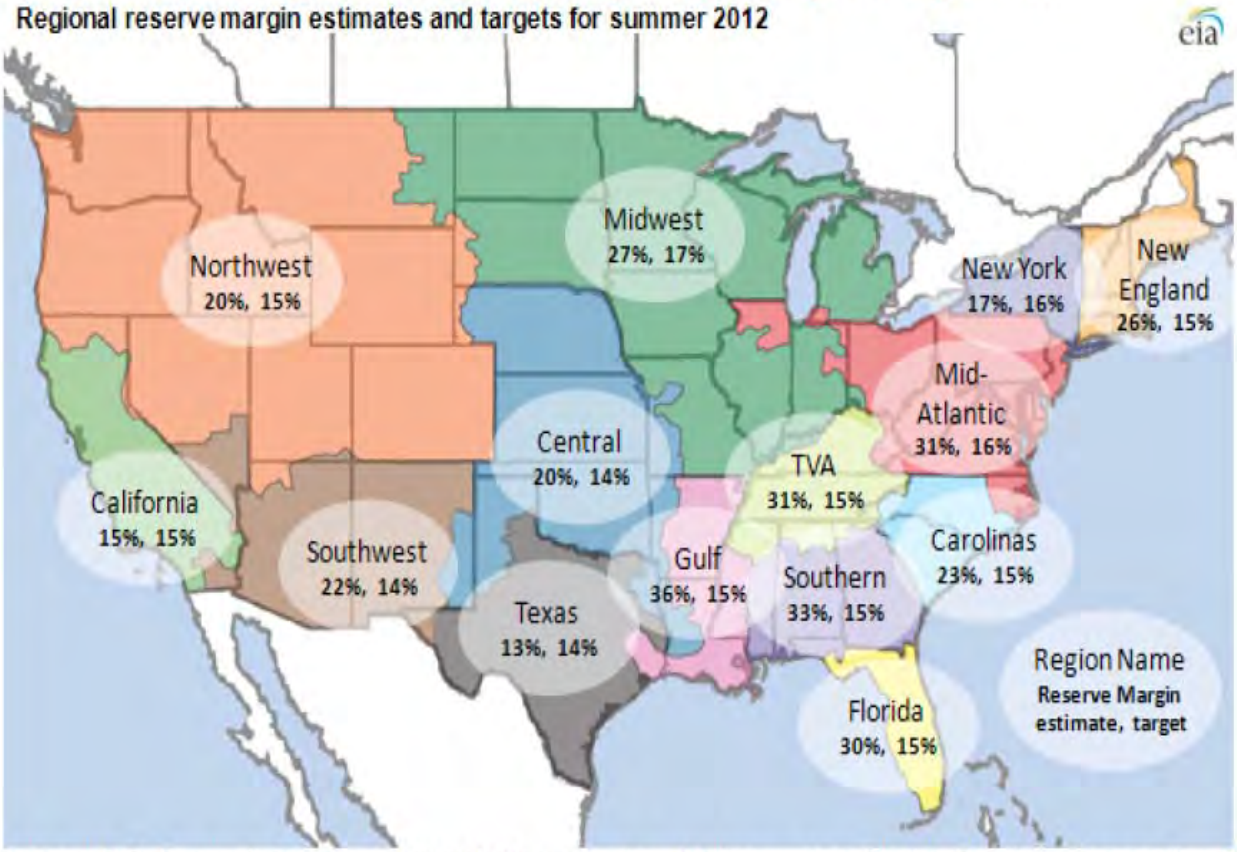
In order to simplify the process of analyzing multiple portfolios and required generation additions, BC Hydro uses an average reserve level, measured in per cent, that has been determined by the LOLE and ELCC calculations. … The average reserve level for BC Hydro that results from the above calculation is currently 14 per cent. [Emphasis added]"
Source: BC Hydro 2008 Long Term Acquisition Plan regulatory filing, Appendix F10, Calculation of Capacity Planning Reserves.

PJM Market Region:
"The purpose of the Reserve Requirement Study (RRS) is to determine the Forecast Pool Requirement (FPR) and the Demand Resource (DR) Factor. This is accomplished by calculating the Installed Reserve Margin (IRM) for future planning periods. … "This Study satisfies all North America Electric Reliability Corporation (NERC) / ReliabilityFirst Corporation (RFC) Adequacy Standard BAL–502–RFC–02 Resource Planning Reserve Requirements. This Standard requires that the Planning Coordinator establish reliability parameters that support a generation Loss of Load Expectation (LOLE) of one occurrence in ten years. Per the final 2010 NERC audit report, PJM was found to be 100% compliant with Standard BAL–502–RFC–02." … "Based on results from this Study (including the Appendix B sensitivity analyses), PJM Staff recommends a 15.5% IRM [Emphasis added – IRM = Installed Reserve Margin] for the 2012/2013 Delivery Year, and a 15.3% IRM for the 2013 / 2014 and 2014/2015 Delivery Years."

US Energy Information Administration Summer 2012 Outlook:
On June 1, 2012, the US Department of Energy's Energy Information Administration (DOE EIA) released the following graphic which shows the regional reserve margin estimates and the regional reserve margin target for 2012. All of the regional reserve margin targets indicated on the graphic are in the 14-17% range.

Reserve electric generating capacity helps keep the lights on

Regional reserve margin estimates and targets for summer 2012



Source: U.S. Energy Information Administration, based on North American Electric Reliability Corporation, 2012 Summer Short-Term Reliability Assessment.

REFERENCE: Appendix 4.2 Manitoba Hydro Supply and Demand Tables; Section: 5; Page No.: 120

QUESTION:

Do any of the Contracted Exports included in the No New Resources case require ``reserves`` (per Chapter 4, page 36)

RESPONSE:

The existing Diversity Contracts totaling 550 MW (at generation) require that both parties provide capacity reserves in addition to the capacity and energy obligations. The reserves associated with the Diversity Contracts are included in the calculation of reserves shown in the Supply and Demand Tables for capacity provided in Appendix 4.2 of this submission.

The obligation to provide capacity reserves under the Diversity Contracts ends in 2014/15. No other existing or proposed contracts contain reserve obligations.

REFERENCE: Appendix 4.2 Manitoba Hydro Supply and Demand Tables; Section: 5; Page No.: 120

QUESTION:

What accounts for the 55 MW of "Proposed Exports" in the No New Resources case - 2013 NFAT Update?

RESPONSE:

As stated in Chapter 12 (page 8, line 5) the 55 MW refers to a new five-year 50 MW Term Sheet with Minnesota Power beginning in 2015/16 which was signed in May, 2013.

REFERENCE: Appendix 4.2 Manitoba Hydro Supply and Demand Tables; Section: 5; Page No.: 120

QUESTION:

Please describe the existing contracts that contribute to the annual values shown in the "Contracted Exports" row in the No New Resources case - 2013 NFAT Update.

RESPONSE:

Please refer to Table 1.8 of Appendix 9.3 for a listing of long-term export contracts common to all development plans for the NFAT 2013Update evaluation. Those contracts with an existing or signed status in Table 1.8 are included in the Contracted Exports row of the Supply and Demand Tables.

REFERENCE: Appendix 4.2 Manitoba Hydro Supply and Demand Tables; Section: 5; Page No.: 120

PREAMBLE: In the NFAT 2012 Reference cases there are no imports after 2024/25 and there is no discussion in Chapter 12 regarding new import contracts.

QUESTION:

In the No New Resources case - 2013 NFAT Update, please indicate what contributes to the annual values shown for Proposed Imports after 2024/25.

RESPONSE:

As stated in Chapter 12 (page 8, line 2) the proposed 200 MW GRE Diversity Agreement which starts in 2014/15 was extended to end in 2030/31, as opposed to the end date of 2025/26 used in the 2012 planning assumptions. This accounts for the annual values shown for Proposed Imports after 2024/25.

REFERENCE: Appendix 4.2 Manitoba Hydro Supply and Demand Tables; Section: 5; Page No.: 16

QUESTION:

Please reconcile the Contracted Imports and Proposed Imports in the No New Resources - NFAT 2012 Reference case with the contract values and terms discussed in Chapter 4, page 42 and set out in Chapter 5, page 7

RESPONSE:

The capacity values stated in Chapter 4 and Chapter 5 are referenced at the border and the capacity values in the 2012 Reference No New Generation Supply and Demand Tables are referenced at generation. The difference between the two values is the 10% transmission losses associated with delivering power from the generating stations to the point of delivery.

Please refer to the response to CAC/MH I-0064 for a table showing both capacity values for current import contracts.

The energy values referenced in Chapter 4 compare to the sum of the energy values in the Contracted Imports and Proposed Imports rows of the 2012 Reference No New Resources Supply and Demand Tables. Both of these energy values are referenced at generation.

REFERENCE: Chapter 4: The Need for New Resources; Section: 4.3.2.1; Page No.: 38

QUESTION:

Is it the practice in other hydro-based utilities for dependable energy to be determined based on the "lowest recorded coincident water supply conditions"? Please provide examples of any other hydro utility employing this practice.

RESPONSE:

Yes, it is the practice in other hydro-based utilities for dependable energy to be determined based on the "lowest recorded coincident water supply conditions".

General Finding No 1 of BC Hydro's March 8-9, 2005 Resource Option Workshop Technical Session stated:

"To assure that there is adequate energy to meet its existing commitments; BC Hydro uses the driest water year in its historical record to define the firm energy capability of its hydro resources. This practice is commonly found in large energy constrained hydro systems and is identical to the standard used by BPA." BPA is the Bonneville Power Administration, which operates a hydro system in the US Pacific Northwest to the south of British Columbia.

REFERENCE: Chapter 4: The Need for New Resources; Section: 4.3.2.1; Page No.: 38

QUESTION:

If not, what other bases are used for establishing "dependable energy" from hydro-electric facilities for purposes of generation planning?

RESPONSE:

Please see Manitoba Hydro's response to CAC/MH I-054a.

REFERENCE: Chapter 4: The Need for New Resources; Section: 4.3.2.1; Page No.: 38

QUESTION:

Please justify the employment of lowest recorded coincident water supply condition as the basis for dependable energy.

RESPONSE:

As noted in Manitoba Hydro's response to CAC/MH I-54a, it is the practice in hydro-based utilities for dependable energy to be determined based on the "lowest recorded coincident water supply conditions".

The lowest recorded coincident water supply conditions on Manitoba Hydro's 99 year hydraulic record are an actual drought event that occurred beginning in 1939, and intensified through the winter of 1940/41. Manitoba winters are harsh, and an energy shortage in Manitoba is likely to occur during the season of the highest demand – winter. Unlike a shortage of capacity in a thermal system, which might result in rotating power outages for a period of hours for several consecutive days of extreme system loading, a significant shortage of energy in Manitoba could result in rotating power outages in Manitoba for a period of weeks or longer in the middle of winter. Designing for such a known drought event is consistent with Manitoba Hydro's purpose as stated in the Manitoba Hydro Act as "to provide for the continuance of a supply of power adequate for the needs of the province".

REFERENCE: Appendix 4.1 Manitoba Hydro Generation Planning Criteria; Page No.: 5

QUESTION:

Please describe in more detail the rationale for the treatment and limitations on Imports for purposes of determining dependable energy resources.

RESPONSE:

The energy criterion contains the statement "The total quantity of energy considered as dependable energy from imports shall be limited to that which can be imported during the Off Peak Period, and shall not exceed the quantity of export contracts in effect at the time plus 10% of the Manitoba load."

The reference to 10% of the Manitoba load has been in the Manitoba Hydro planning criteria since 1977. This 10% of the Manitoba load is not the limiting criteria for imports in that it does not impact the need for new resources in 2022.

The limitation to that which can be imported during the off-peak period allows slightly more imports than previously assumed under previous requirements that required an energy purchase contract or was expected to be in effect during the time being studied. Manitoba Hydro currently has capacity export obligations over the on-peak hours during the time when no new resources are required and it would not be appropriate to assume, on the planning horizon, that Manitoba Hydro is importing during on-peak hours when in fact it has export obligations.

Manitoba Hydro notes that the capacity criterion contains a factor, the reserve against breakdown of plant and equipment and increase in demand above forecast, to cover uncertainty in the capacity supply/demand balance. The energy criterion contains no similar

factor to cover the uncertainty in the energy supply/demand balance. There is, however, a number of sources of uncertainty in the dependable energy supply situation: transmission outages which may restrict imports to less than the 100% of the assumed 700 MW US firm transfer capability for the planning horizon; the ability of the thermal generation units to perform over the longer term at the projected capacity factors; actual average annual wind generation; increased Manitoba load; and timing of water flows during a critical flow period. Further, there is always the possibility of a drought occurring worse than the drought of record. Although Manitoba Hydro does not explicitly plan for such energy contingencies, including a drought worse than the drought of record, the ability to import on-peak if necessary serves as the reserve margin to protect against loss of load during such energy contingencies.

REFERENCE: Appendix 4.2 Manitoba Hydro Supply and Demand Tables; Section: 5; Page No.: 122

QUESTION:

In the No New Resources case - 2013 NFAT Update, please indicate how the annual energy values shown for Contracted Imports and Proposed Imports were determined (i.e. what was the limiting factor)?

RESPONSE:

The energy values for contracted and proposed imports are based on the signed contracts and term sheets under negotiation at the time and are shown in the tables below.

Current Import Contracts
@ generation

Supplier	Contract Name	Winter Peak Capacity (MW)	Type	Term
NSP	NSP 150 SD	165	Seasonal Diversity	May 1, 1995 to April 30, 2015
	NSP 200 SD	220	Seasonal Diversity	Nov 1, 1996 to April 30, 2015
	NSP 500 ESA	0	Energy Services Agreement	May 1, 2009 to April 30, 2019
GRE	GRE 150 SD	165	Seasonal Diversity	May 1, 1995 to Oct 31, 2014
Total		**550**		

*The NSP Energy Services Agreement provides Firm Transmission Service. Imports under this agreement are reflected as a portion of Market Purchases on the Dependable Energy Supply and Demand Table.

Proposed Import Contracts
@ generation

Supplier	Term Sheet Name	Winter Peak Capacity (MW)	Type	Term
GRE	GRE 200 SD	220	Seasonal Diversity	Nov 1, 2014 to April 30, 2030
Total		**220**		

Additional available energy imports in accordance with the Generation Planning Criteria are included as Market Purchases. These imports are limited by the 700 MW of existing firm transmission service.

Please refer to CAC/MH I–057 for an illustration of the calculation that determines the maximum level of imports that can be considered as dependable energy.

REFERENCE: Appendix 4.2 Manitoba Hydro Supply and Demand Tables; Section: 5; Page No.: 122

QUESTION:

In the No New Resources case - 2013 NFAT Update, please provide a schedule that sets out for each year through to 2031/32 the maximum level of imports that can be considered dependable energy in accordance with Manitoba Hydro's Generation Planning Criteria and show how each year's value was calculated.

RESPONSE:

The following schedule illustrates the calculation that determines the maximum level of imports that can be considered as dependable energy for each year through to 2031/32 based on the Generation Planning Criteria.

Generation Planning Criteria

Calculation of Dependable Energy Imports (GW.h)

No New Resources

	1	2	3	4	5	6
fiscal year	Manitoba Net Load	Lake St. Joseph Export	Total Exports Net of Adverse Water	10% MB Load & Exports	Off-Peak Transmission Limit	Maximum Import
				(1+2)*10%+(3-2)	700 MW, 47.62% CF	lesser of 4 or 5
2013/14	25131	145	3156	5539	3068	3068
2014/15	25472	145	3156	5573	3068	3068
2015/16	25725	145	2200	4642	3068	3068
2016/17	25959	145	2056	4521	3068	3068
2017/18	26173	145	2056	4543	3068	3068
2018/19	26501	145	2056	4576	3068	3068
2019/20	26850	145	2056	4610	3068	3068
2020/21	27202	145	1846	4436	3068	3068
2021/22	27570	145	1804	4430	3068	3068
2022/23	27939	145	1804	4467	3068	3068
2023/24	28317	145	1804	4505	3068	3068
2024/25	28707	145	1804	4544	3068	3068
2025/26	29095	145	350	3129	3068	3068
2026/27	29479	145	307	3124	3068	3068
2027/28	29865	145	307	3163	3068	3068
2028/29	30302	145	307	3207	3068	3068
2029/30	30744	145	307	3251	3068	3068
2030/31	31149	145	145	3129	3068	3068
2031/32	31562	145	145	3171	3068	3068

Notes:

1. Manitoba Net Load results from subtracting the expected savings from planned DSM programs from the electric load forecast.
2. Obligations under the Lake St. Joseph agreement are included in contracted exports in the Supply and Demand Dependable Energy tables. For this calculation, obligations under the Lake St. Joseph agreement are added to Manitoba Load.
3. Total Exports Net of Adverse Water is the sum of contracted and proposed exports net of adverse water as described on Page 13 of Appendix 9.3.
4. Off-Peak Transmission Limit represents the total energy which can be imported over the 700MW firm import capability of the existing US interconnection during the off-peak hours.

REFERENCE: Chapter 4: The Need for New Resources; Section: 4.3.2; Page No.: 42

QUESTION:

Based on Manitoba Hydro's seasonal load profile what is the maximum MW of winter peak that could be addressed through diversity agreements in the years 2023/24 and 2031/32?

RESPONSE:

The difference between Manitoba Hydro's summer peak and winter peak is approximately 1,500 MW in 2023/24 and 1,600 MW in 2031/32.

From the perspective of Manitoba Hydro's existing system, the maximum amount of diversity agreements that Manitoba Hydro can enter into is limited to the firm import capability of 700 MW.

REFERENCE: Appendix 4.2 Manitoba Hydro Supply and Demand Tables; Section: 5; Page No.: 120

PREAMBLE: The Generation Planning Criteria (Appendix 4.1, page 4) states that the imports that may be considered dependable energy are impacted by the amount of energy that can be imported in the off-peak period and the quantity of export contracts

QUESTION:

Please explain why the level of assumed imports included as capacity and energy resources is unchanged as between the No New Resources case (pages 120-123) and the Preferred Development Plan (pages 124-127) even though the interconnection capability and the level of export contracts have both increased in the latter.

RESPONSE:

The proposed 750 MW US interconnection is assumed to provide for additional import capability of 750 MW beginning in 2020/21. Prior to this date energy imports for the Preferred Development Plan are the same as shown in the No New Resources Table Supply and Demand Tables as they both include the maximum amount of imports, using the existing US and Canadian interconnections, as stipulated in the Generation Planning Criteria.

Beginning in 2020/21, new energy imports are included in the Preferred Development Plan to account for the added import capability provided by the new U.S. interconnection that supports energy imports associated with the Minnesota Power Sale Agreements and the Wisconsin Public Service Term Sheet as well as additional market purchases.

The Preferred Development Plan does not include any additional capacity import contracts and therefore capacity imports do not change from the No New Resources Supply and Demand Tables.

The following tables illustrate the energy import amounts included in the No New Resources and the Preferred Development Plan Supply and Demand Tables for the five years following the in-service date of the proposed 750 MW US Interconnection.

No New Resources (@ generation)

	2020/21	2021/22	2022/23	2023/24	2024/25
Capacity Imports (MW)					
Contracted	385	385	385	385	385
Proposed	220	220	220	220	220
Total Capacity Imports	**605**	**605**	**605**	**605**	**605**
Energy Imports (GWh)					
New Imports					
Contracted					
Proposed					
Total New Imports	0	0	0	0	0
Base Supply Imports					
Contracted	1639	1639	1639	1639	1639
Proposed	936	936	936	936	936
Market Purchases	493	493	493	493	493
Total Base Supply Imports	3068	3068	3068	3068	3068
Total Energy Imports	**3068**	**3068**	**3068**	**3068**	**3068**

Preferred Development Plan (GWh @ generation)

	2020/21	2021/22	2022/23	2023/24	2024/25
Capacity Imports (MW)					
Contracted	385	385	385	385	385
Proposed	220	220	220	220	220
Total Capacity Imports	**605**	**605**	**605**	**605**	**605**
Energy Imports (GWh)					
New Imports					
Contracted	928	1113	1113	1113	1113
Proposed					
Total New Imports	928	1113	1113	1113	1113
Base Supply Imports					
Contracted	1639	1639	1639	1639	1639
Proposed	936	936	936	936	936
Market Purchases	493	957	1050	1050	1050
Total Base Supply Imports	3068	3532	3625	3625	3625
Total Energy Imports	**3996**	**4645**	**4738**	**4738**	**4738**

REFERENCE: Appendix 4.2 Manitoba Hydro Supply and Demand Tables; Section: 5; Page No.: 120

PREAMBLE: Appendix 4.2, page 5 defines Contracted Exports as "the sum of all signed export contracts for capacity that are common to all development plans"

QUESTION:

Based on the definition of Contracted Exports please explain why the values change from plan to plan. For example, in the No New Resources case there are no values after 2024/25 (page 120), whereas under the Preferred Plan (page 124) there are values through to 2034/35.

RESPONSE:

The definition for Contracted Exports in Appendix 4.2 page 5 should read:

"Contracted Exports

Contracted Exports is the sum of all signed export contracts for capacity that are common to all development plans. In addition, signed contracts contingent on new development specific to each development plan are included."

The Preferred Development Plan includes five signed export contracts contingent upon future development of hydro resources in Manitoba. Please reference Table 6.4 for a listing of these contracts.

REFERENCE: Appendix 4.2 Manitoba Hydro Supply and Demand Tables; Section: 5; Page No.: 124

QUESTION:

Please provide a schedule that for the Preferred Plan lists the lists all of the export contracts included (both currently signed and proposed) and shows the contribution of each to the annual values (MWs and GWhs) shown on pages 124-127 for the Contracted Exports and Proposed Export rows.

RESPONSE:

Please refer to the response for CAC/MH I–081.

REFERENCE: Chapter 4: The Need for New Resources; Section: 4.1; Page No.: 35

PREAMBLE: In the Bipole III EIS, Chapter 2: Need and Alternatives, Manitoba Hydro expressed concern about the percentage of generation from northern Manitoba and the impact of outages on the Bipole I&II corridor or at the Dorsey Station on its overall load serving capability as justification of the need for Bipole III. These concerns are also set out in Chapter 5, pages 25-26 of the current Application.

QUESTION:

Given these concerns about Manitoba Hydro`s load serving capability in the event of an extended HVdc outage (Transmission corridor or converter station) has Manitoba Hydro established any generation planning criteria that focus on its capability to meet firm load commitments in the event of an extended outage on its HVdc system (e.g., deliverable dependable generation must be sufficient to meet x% of firm commitments in the event of a single major outage anywhere on the HVdc system)? If not, why not?

RESPONSE:

A probabilistic (loss of load expectation or LOLE) analysis of the Manitoba Hydro system, which includes the possibility of major outages of Bipoles 1, 2 and/ or 3 is included in Appendix 13.1 of the NFAT Filing. A loss of load expectation of 0.1 days/ year on an annual base is used as the reliability objective, and is commonly used across North America.

REFERENCE: Chapter 4: The Need for New Resources; Section: 4.3.2; Page No.: 43

QUESTION:

Has Manitoba Hydro identified and reviewed all of opportunities for supply-side enhancement? If yes, please provide a copy of the review. If not, how are potential opportunities (e.g. Kelsey Rerunnering) identified?

RESPONSE:

Manitoba Hydro has identified and reviewed all opportunities for supply-side enhancements for existing generating facilities. In general, undertaking supply-side opportunities in conjunction with ongoing capital maintenance programs has been the most cost effective means of maximizing the generating capacity and efficiency of those facilities that are near the end of their life. As a result, a specific document summarizing all past and future supply-side opportunities is not available.

Most of the supply-side opportunities achieved to date were at some of the oldest generating facilities in Manitoba Hydro's system. For example, enhancements on the Winnipeg River generating stations have achieved an increase in average annual energy production in the order of 5 percent to 10 percent. These enhancements were undertaken by taking advantage of planned unit outages for major repairs to upgrade the power-producing components (turbines, generators and transformers) of these facilities

In some specific cases, opportunities for increased generation from existing facilities were economically justified outside of normal maintenance outages. An example of this would be the Kelsey Rerunnering Project, where it was identified that there was an opportunity to significantly increase the powerhouse discharge capability to better match the average river flow; thereby reducing spill and increasing overall production energy. When completed, the

Kelsey Rerunnering Project will increase the capacity of Kelsey Generating Station by 35%, with an expected gain in average annual energy production of over 400 Gwh per year.

Manitoba Hydro will continue to monitor the condition of its existing generating facilities and assess the most economic alternatives for maintaining operation while optimizing the generating capability of these facilities.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.1; Page No.: 3

QUESTION:

Please reconcile the 550 MW attributed to contracted imports in Table 5.1 with the 500 MWs of capacity attributed to the four import contracts currently in effect per Table 5.2

RESPONSE:

The 550 MW of Contracted Imports in Table 5.1 is referenced "at generation" and the 500 MW of Contracted Imports in Table 5.2 is referenced at the border. The difference between the two values is the 10% transmission losses associated with delivering power from the generating stations to the point of delivery. The following table shows both capacity values for each import agreement.

Current Import Contracts

Supplier	Contract Name	Capacity @ Border	Capacity @Generation	Type	Term
NSP	NSP 150 SD	150 MW	165 MW	Seasonal Diversity	May 1, 1995 to April 30, 2015
	NSP 200 SD	200 MW	220 MW	Seasonal Diversity	Nov 1, 1996 to April 30, 2015
	NSP 500 ESA*	0	0	Energy Services Agreement	May 1, 2009 to April 30, 2019
GRE	GRE 150 SD	150 MW	165 MW	Seasonal Diversity	May 1, 1995 to April 30, 2015
Total		**500 MW**	**550 MW**		

*The NSP Energy Services Agreement provides Firm Transmission Service. Imports under this agreement are shown as Market Purchases on the Dependable Energy Supply and Demand Tables.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.1.2; Page No.: 5

QUESTION:

Are there any statutory operating restrictions on the natural gas units at either Selkirk or Brandon?

RESPONSE:

Yes, there are operating restrictions on both Brandon Generating Station Units 6 & 7 as well as Selkirk Units 1 &2. The operating restrictions are environmental in nature and specified in the clauses and conditions of the following Environment Act licenses:

Brandon Generating Station Units 6 &7

- Environment Act Licence No. 2497R
- which is publically available the website http://www.gov.mb.ca/conservation/eal/archive/2001/licences/2497r.html

Selkirk Generating Station Units 1 &2

- Environment Act Licence No. 1645R5
- which is publically available at the website http://www.gov.mb.ca/conservation/eal/archive/older/licences/1645r5.pdf

REFERENCE: Chapter 4: The Need for New Resources; Section: 4.3.2; Page No.: 41

QUESTION:

Has any consideration been given to converting the remaining coal-fired turbine unit at Brandon GS to natural gas? If not, why not? If yes, why was it not included as an option in Chapter7?

RESPONSE:

Over the years, Manitoba Hydro has considered the possibility of coal to natural gas conversion of Brandon Generating Station Unit 5. Some of the overriding considerations were the age of the unit (Unit 5 will be 50 years old in 2019), the low efficiency of the unit upon conversion, (as experienced with the coal to natural gas conversion of the Selkirk Generating Station) and uncertainty regarding future licensing and regulatory requirements including proposed federal GHG regulation of natural gas generation.

While Manitoba Hydro will give further consideration to such a conversion, at this time the feasibility of converting Brandon Generating Station Unit 5 assets post-2019 from coal to natural gas has not been assessed and therefore it was not considered as an option in Chapter 7. The results of the assessment, when completed, will be incorporated into future power resource plans.

It should be noted that the Selkirk Generating Station is subject to the same uncertainty with respect to GHG legislation and regulation.

REFERENCE: Volume: Chapter 4: The Need for New Resources; Section: 4.3.2; Page No.: 42

QUESTION:

Is all of the import energy relied on for planning purposes (per lines 19-21) associated with Energy Service Agreements (as opposed to Diversity Agreements)?

RESPONSE:

No, not all of the import energy relied on for planning purposes is associated with the Energy Services Agreements. For planning purposes imports are included as dependable energy up to the limit set out in the Generation Planning Criteria.

In the NFAT 2012 Reference Supply and Demand Tables for No New Resources in Appendix 4.2, pages 18 and 19, it is the total of Contracted Imports, Proposed Imports and Market Purchases that provide the import energy relied on for planning purposes. Contracted Imports and Proposed Imports represent energy imports under the Diversity Agreements and Market Purchases represent other energy imports on firm transmission provided for by the Energy Services Agreement.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.2.4; Page No.: 16

PREAMBLE: Manitoba Hydro`s Submission to the CEC: Need for and Alternatives to the Wuskwatim Project, Chapter 5, Table 5.4 had higher values for both US and Canadian export and import capabilities

QUESTION:

Please explain why the Firm Export and Import limits have declined relative to those in Manitoba Hydro's submission to the CEC regarding the Need for and Alternatives to the Wuskwatim Project.

RESPONSE:

Chapter 5, Section 5.2.2.4 Current Interconnection Transfer Capability, Table 5.7 Export Transfer Limits lists a Firm Export Schedule Limit of 2300 MW for the combined US, Ontario and Saskatchewan interfaces. This export limit appears consistent with 2003 assumptions for Wuskwatim which state "After both operating limitations and market limitations have been considered, the firm capability for on-peak export transactions is limited to a total of about 2300 MW to the combined US and Canadian markets[4]."

Chapter 5, Section 5.2.2.4 Current Interconnection Transfer Capability, Table 5.8 Import Transfer Limits lists a Firm Transfer Capability for the Planning Horizon of 700 MW. This import limit appears consistent with 2003 assumptions for Wuskwatim which state "Manitoba Hydro currently has approximately 700-1200 MW of firm import capability available from the US,

[4] Submission to the Manitoba Clean Environment Commission titled The Wuskwatim Project April 2003 : Chapter 5, page 23.

Saskatchewan and Ontario depending on ambient temperature and the status of critical transmission lines[5]."

Transfer limits at key interfaces, such as transmission interconnections can degrade over time due to changing system conditions and regional electricity flow patterns. Over the long term, transfer capability is protected by long-term firm transmission reservations. If necessary, system improvements will be made to transmission system components, such as conductors, transformers, and capacitors to maintain the transfer capability protected by long-term firm transmission reservations. Transfer capability above the long-term firm quantity may be available on a non-firm or short-term firm basis, but the availability of this capability cannot be assured on a long term basis.

[5] Submission to the Manitoba Clean Environment Commission titled The Wuskwatim Project April 2003 : Chapter 4, page 26.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.2.4; Page No.: 16

QUESTION:

What is the maximum current maximum export capability in terms of on-peak kWhs?

RESPONSE:

As noted in Manitoba Hydro's response to PUB/MH I-16a, utilizing a U.S. Firm Export Schedule Limit of 1,950 MW yields a theoretical export capability of 17,090 GWh per year.

In terms of on-peak kilo-watt hours, using a 5x16 definition of on-peak (47.6% capacity factor) yields 8,140 GWh per year during the on peak period. As 1 GWh = 1,000,000 kWh, 8,140 GWh per year is equivalent to 8,140,000,000 kWh per year.

As also indicated in Manitoba Hydro's response to PUB/MH I-16a, these values do not allow for any interconnection outages or allowance for scheduling uncertainty, and also assume surplus water/ energy and generation capacity would be available from Manitoba resources under all conditions, including peak winter load conditions in Manitoba.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.2.4; Page No.: 17

QUESTION:

Assuming exports to the US are using the maximum capability available (1,950 MW) what is the maximum amount that can be exported to Ontario & Saskatchewan (in terms of MWs and on-peak kWhs)?

RESPONSE:

At times, and assuming supply is available within Manitoba, it would be possible to simultaneously export 1,950 MW to the US, 200 MW to Ontario and 150 MW to Saskatchewan, which are the Firm Export Schedule Limits listed in Table 5.7 of Chapter 5 of the NFAT Filing. However, due a number of factors, including to transmission system limits within Saskatchewan and Ontario, the relatively small demand within Saskatchewan and Northwestern Ontario, the lack of a competitive energy market in Saskatchewan, and Ontario market rules which can cause Manitoba Hydro's offers to sell into Ontario to be constrained off at times even though they are economic, Manitoba Hydro can not quantify the maximum amount of energy that can be exported to Ontario & Saskatchewan.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.3; Page No.: 18

QUESTION:

Are the 150 MW of contingency reserve served out of Manitoba Hydro's 12% reserve margin? If not, how is it accounted for in the Appendix 4.2 supply-demand tables?

RESPONSE:

Yes. The 12% planning reserve margin would include the 150 MW of contingency reserve carried on the operating horizon.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.3; Page No.: 18

QUESTION:

Please explain the difference between the 150 MW requirement for contingency reserve described on page 18 and the 225 MW value for operating reserves and transmission reliability described on page 15.

RESPONSE:

The 225 MW reserve margin on the U.S. interconnection is for both operating reserves and transmission reliability margin. Contingency reserves are a type of operating reserve. Under the Manitoba Hydro Contingency Reserve Sharing Agreement with MISO, Manitoba Hydro must have available 150 MW of generating capability and an equivalent amount of transmission capacity reserved to enable the delivery of those reserves to MISO. The transmission reliability margin is reserved for unscheduled flows of electricity.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.2.4; Page No.: 21

QUESTION:

Does the sale of Ancillary Services by Manitoba Hydro require the use of transmission capacity that could other be used for exports?

RESPONSE:

The sale of ancillary services requires the use of transmission. Chapter 5, Section 5.2.4, page 21 explains the use of the External Asynchronous Resource (EAR) to provide energy and/ or ancillary services. Manitoba Hydro places offers to sell ancillary services and/ or energy through the EAR, and MISO will select which, if any, offer it wishes to accept when it is economic to do so.

Manitoba Hydro's offer to sell energy and/ or ancillary services through the EAR is structured to reflect the economics of providing energy and/ or ancillary services using this resource. The selection or clearing of the offer by MISO will determine if whether energy or ancillary services will be provided in any particular period, and both products require transmission. However, ancillary services will be delivered instead of energy in any particular period if it is in the best financial interest of both the MISO market and Manitoba Hydro as represented by the offer pricing.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.2.2; Page No.: 40

QUESTION:

Is Manitoba Hydro generation able to "reach" all of MISO's market footprint or is there transmission congestion that limits its reach?

RESPONSE:

The term reach is a matter of degree in a large interconnected power system. MISO dispatches generation in its market footprint every five minutes and thus what could be defined as “reach” can change every five minutes.

In general, Manitoba Hydro’s generation would be able to reach all of the MISO market in most, but not all hours of the year. In a minority of the hours of the year, transmission congestion somewhere on the power grid would limit the ability of Manitoba Hydro generation to “reach” all of the MISO market without MISO performing a redispatch of generation resources within the market footprint to enable otherwise economic Manitoba Hydro resources from being curtailed.

Manitoba Hydro’s generation would be able to “reach” a particular customer provided there is a power sales agreement utilizing firm transmission service from Manitoba Hydro to the customer’s designated load.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.2.2; Page No.: 40

QUESTION:

If the current reach is restricted, please describe the size and make-up (demand, generation, resource mix and marginal generation) of the area that Manitoba Hydro can "reach".

RESPONSE:

Please see Chapter 5, Table 5.11, and Sections 5.4.2 and 5.4.3, and Appendix 5.1 for a description of Manitoba Hydro's markets including generation mix and peak demand. MISO Market Marginal Generation is discussion in Chapter 5, Section 5.4.2.4.

As indicated in Manitoba Hydro's response to CAC/MH I-073a, in general, Manitoba Hydro's generation would be able to reach all of the MISO market in most, but not all hours of the year. In the minority of hours of a year where transmission congestion somewhere on the power grid would limit the ability of Manitoba Hydro generation to "reach" all of the MISO market it is not possible to quantify the sub-region of the market being "reached".

As also indicated in the response to CAC/MH I-073a, the term reach is a matter of degree in a large interconnected power system. MISO dispatches generation in its market footprint every five minutes and thus what could be defined as "reach" can change every five minutes. Therefore, in practice there is no determination as to whether a particular load is "reached" by a generator or to what degree of congestion is required before it is said the load is not reached by a particular generator.

REFERENCE: Appendix 5.2 MISO Market Products, Operation and Locational Marginal Pricing; Page No.: 3

QUESTION:

Does Manitoba Hydro participate at all in MISO's generation capacity market or are all of Manitoba Hydro's MISO sales to MISO's energy and ancillary services markets?

RESPONSE:

As indicated in Chapter 5, Section 5.4.2.4 MISO Market, there are three discrete categories of physical power products that are purchased and sold in the MISO market: energy, generation capacity and ancillary services, and Manitoba Hydro participates in all three markets.

MISO facilitates the market for generation capacity—the MISO Resource Adequacy Construct—through its resource adequacy requirements for load, the tracking of bilateral capacity transactions, and through the MISO Planning Resource Auction for generation capacity.

The sale of generation capacity is an important revenue stream to Manitoba Hydro and revenue obtained is in addition to the value of energy from the MISO energy market. Contracts listed in Appendix 9.3, Section 1.6 Summary of Export/ Import Contracts which have a non zero value in the Capacity column of the table represent the sale or exchange of generation capacity by Manitoba Hydro.

In addition, Manitoba Hydro can sell surplus capacity via MISO's Planning Resource Auction. However it is unable to purchase capacity via the auction process at this time.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.2.4; Page No.: 43

QUESTION:

Is the reference point used for Manitoba Hydro's export price forecasts (i.e, the Minnesota Hub) the relevant LMP location for Manitoba Hydro sales?

RESPONSE:

The Minnesota Hub (MINN HUB) is the primary commercial transaction location in the Upper Midwest as it is the major load centre in that MISO region. Therefore, the Minnesota Hub is the location that external price forecast consultants provide in their analysis.

Manitoba Hydro's point of sale into the MISO market is known as the MHEB node, located at the Manitoba-US border. Manitoba Hydro applies a basis differential to the forecast MINN HUB prices to account for losses and congestion between MINN HUB and MHEB. The congestion and losses factors are reviewed on an annual basis to ensure they remain an accurate representation of pricing differential between the two pricing locations. Specific details of the basis differential between MINN HUB and MHEB are considered Commercially Sensitive Information (CSI) as it impacts pricing negotiations of export contracts. However, details of the basis differential between MINN HUB and MHEB are contained within Manitoba Hydro's Export Price forecasts, in Appendix H of the 2012 Electricity Export Price Forecast, and Appendix E of the 2013 Electricity Export Price Forecast, which have been filed through the CSI process.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.2.4; Page No.: 43

QUESTION:

In terms of the LMP applicable to Manitoba Hydro sales to the MISO market, what were the average system-wide energy price, line loss and congestion components for each month in 2011, 2012 and 2013 to date?

RESPONSE:

MHEB is the pricing location in the MISO market applicable for Manitoba Hydro. The locational marginal price (LMP) at MHEB, and the energy, losses and congestion components used in the determination of the MHEB LMP are provided in the table below.

For more information on the determination LMP, please refer to Appendix 5.2 of the application, Energy Price Formulation in the MISO Energy Market – Locational Marginal Price.

1

MHEB Commercial Pricing Node - Average Monthly All Hours Price and Components (US$/MWh)

	Energy Component	Losses Component	Congestion Component	LMP at MHEB
Jan-11	35.90	-3.01	-2.83	30.05
Feb-11	32.13	-2.73	-5.16	24.24
Mar-11	32.04	-2.96	-4.94	24.14
Apr-11	32.00	-3.58	-5.37	23.05
May-11	31.71	-4.59	-7.93	19.19
Jun-11	31.91	-3.91	-7.96	20.04
Jul-11	43.58	-5.33	-5.01	33.23
Aug-11	35.61	-4.56	-2.26	28.79
Sep-11	27.78	-2.78	-3.78	21.23
Oct-11	28.92	-2.85	-7.75	18.32
Nov-11	27.26	-2.00	-3.45	21.81
Dec-11	28.05	-1.24	-2.62	24.18
Jan-12	25.29	-1.68	-2.84	20.78
Feb-12	25.17	-1.18	-1.71	22.28
Mar-12	22.81	-1.00	-3.77	18.04
Apr-12	23.24	-1.56	-3.36	18.32
May-12	28.36	-2.17	-2.68	23.52
Jun-12	28.55	-2.30	-7.87	18.38
Jul-12	40.28	-4.39	-6.63	29.26
Aug-12	27.72	-3.38	-3.84	20.50
Sep-12	24.52	-3.35	-2.52	18.65
Oct-12	26.79	-2.94	-1.43	22.42
Nov-12	29.28	-2.26	-2.51	24.50
Dec-12	28.07	-0.56	1.36	28.87
Jan-13	28.54	-0.84	0.78	28.48
Feb-13	28.16	-0.79	0.03	27.41
Mar-13	31.59	-2.02	-0.37	29.19
Apr-13	34.00	-2.55	-2.05	29.40
May-13	32.75	-3.15	-4.25	25.35
Jun-13	30.04	-3.34	-2.57	24.14
Jul-13	32.72	-3.55	-1.06	28.11
Aug-13	30.89	-3.42	-1.15	26.32

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.3.2; Page No.: 52

QUESTION:

Would the new transmission interconnections with Saskatchewan be in the north or the south, with the later requiring the use of Manitoba Hydro`s HVdc transmission?

RESPONSE:

New transmission interconnections with Saskatchewan are expected to be in the south. Studies to increase the existing transfer capability by 100 MW have identified that a new 80-km 230 kV line between Birtle, Manitoba and Tantallon, Saskatchewan would be needed. To date, a facility construction agreement for this project has not been completed. Studies to investigate the transmission requirements for up to a 500 MW increase in export capability have not started. It is likely that one viable option for this increase could be a 500 kV line between Winnipeg and Regina.

The 2013 MOU referred to on page 52 of Chapter 5 anticipates the increase in transfer capability to Saskatchewan could be placed in-service in the 2020-2026 timeframe when Keeyask and Conawapa are expected to be in-service. Therefore, Manitoba Hydro's HVdc transmission could be used to transport this power to Winnipeg and additional transmission would then be required between Winnipeg and Saskatchewan.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.3.2; Page No.: 52

QUESTION:

What is the likely timeframe for increased sales to Saskatchewan?

RESPONSE:

Manitoba Hydro and SaskPower are in ongoing negotiations on short and long term transactions. Increased transactions will require the construction of new transmission interconnections which is not likely for at least five years. Major new exports will also require a commitment to Conawapa and new major transmission line construction which will be dependent on the in-service date of Conawapa, assuming a long term Power Purchase Agreement is agreed to.

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.1.2; Page No.: 3

PREAMBLE: The proposed new export sales are described as having "fixed prices".

QUESTION:

Please clarify whether the prices are truly "fixed" (i.e. in the context of being set).

RESPONSE:

Only one of the new export sales contracts has fixed annual prices for capacity and energy where the annual escalation has been pre-established. All the other new export sales contracts have fixed prices that are subject to various escalation provisions which reset the price at the start of each contract year.

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.1.2; Page No.: 3

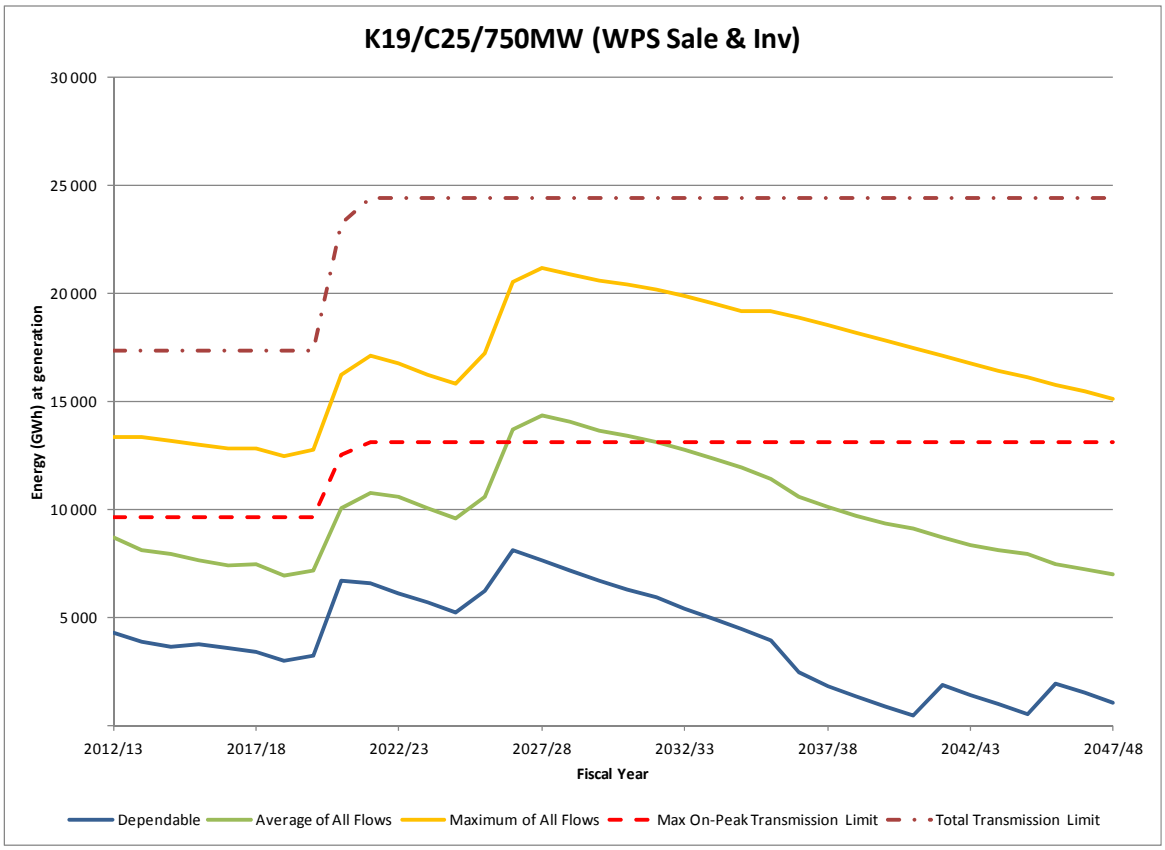
QUESTION:

For each development plan please provide a graph that sets out the amount of surplus energy that would be available for export under dependable, median and maximum flow conditions for the years 2012/13 through 2048/49 and also draw two lines on the graph representing the maximum on-peak energy and total energy that can be exported annually based on the interconnection facilities associated with the development plan.

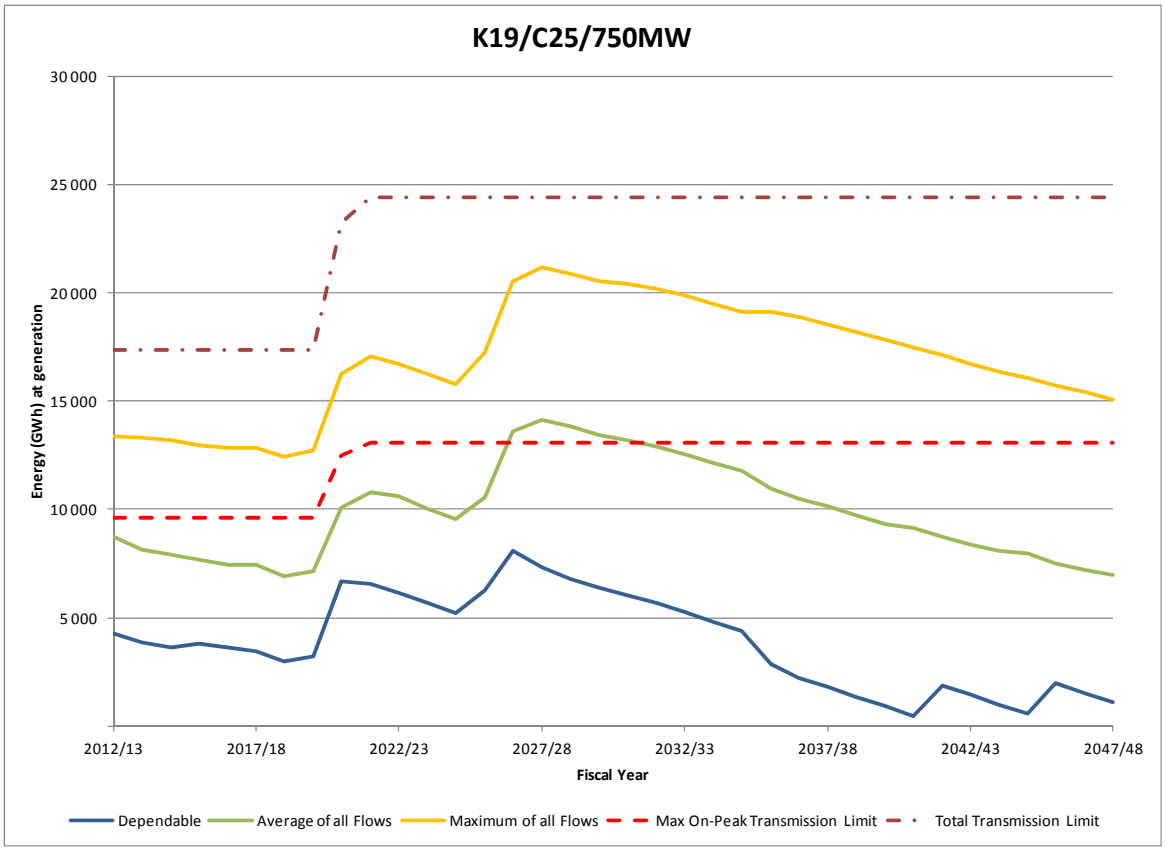
RESPONSE:

The following graphs illustrate the surplus energy available for export under dependable, average and maximum flow conditions for each of the 15 NFAT 2012 Reference Development Plans included in Appendix 4.2. Surplus energy available for export is calculated for each year as Total Power Resources less Manitoba Net Load and represents total exports including contracted and proposed exports. Opportunity energy is also included for the average and maximum flow cases. The graphs also include the maximum on-peak and total export capability of the interconnections associated with each plan.

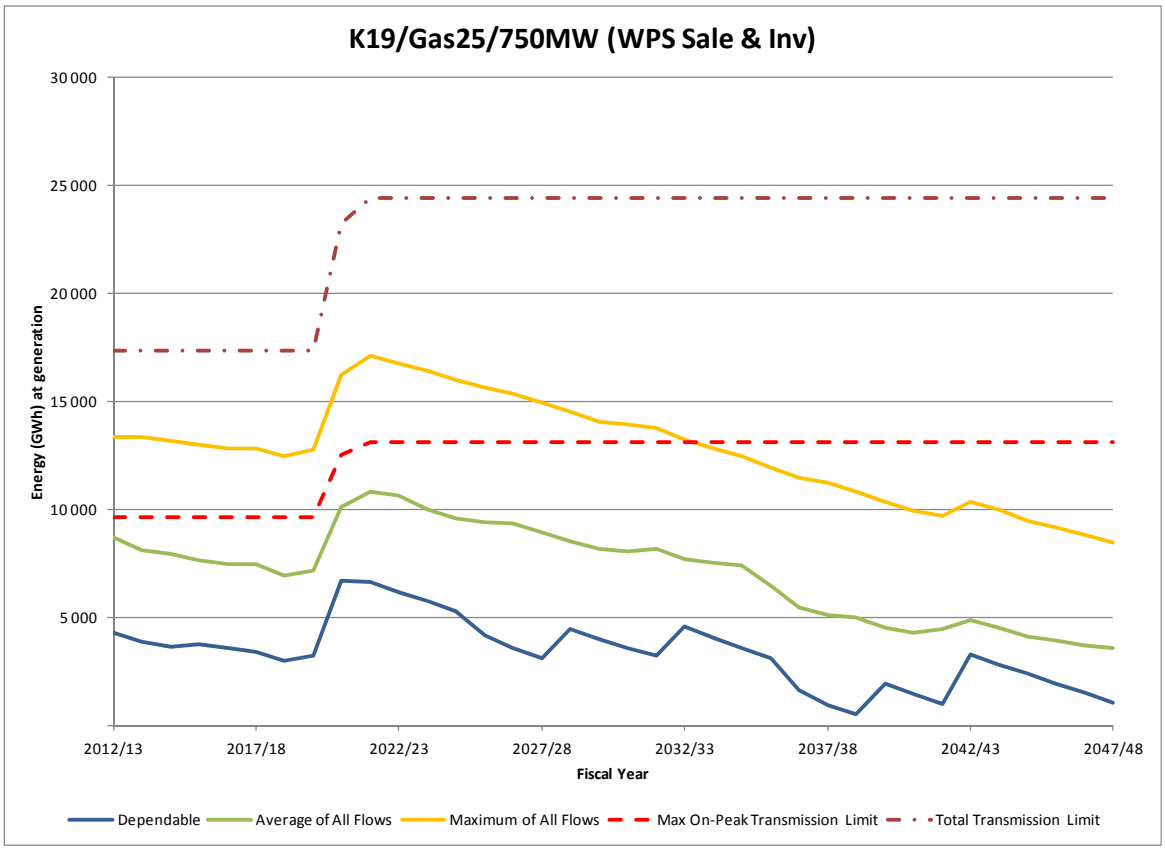
It should be noted that annual energy values do not reflect the actual transmission usage and limitations within each year.


K19/C25/750MW (WPS Sale & Inv)
30 000
25 000
20 000
15 000
10 000
5 000
Energy (GWh) at generation
2012/13
2017/18
2022/23
2027/28
2032/33
2037/38
2042/43
2047/48
Fiscal Year
Dependable
Average of All Flows
Maximum of All Flows
Max On-Peak Transmission Limit
Total Transmission Limit

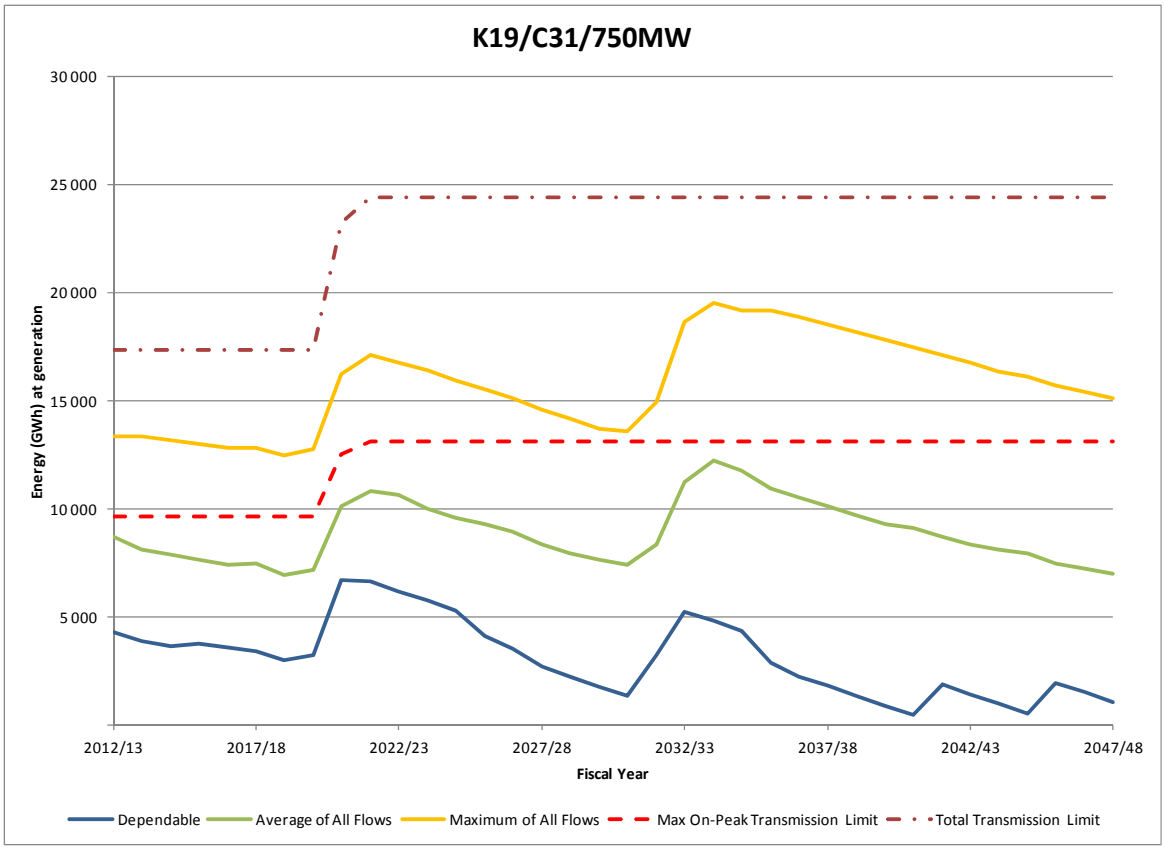
1


K19/C25/750MW
30 000
25 000
20 000
15 000
10 000
5 000
Energy (GWh) at generation
2012/13
2017/18
2022/23
2027/28
2032/33
2037/38
2042/43
2047/48
Fiscal Year
Dependable
Average of all Flows
Maximum of all Flows
Max On-Peak Transmission Limit
Total Transmission Limit

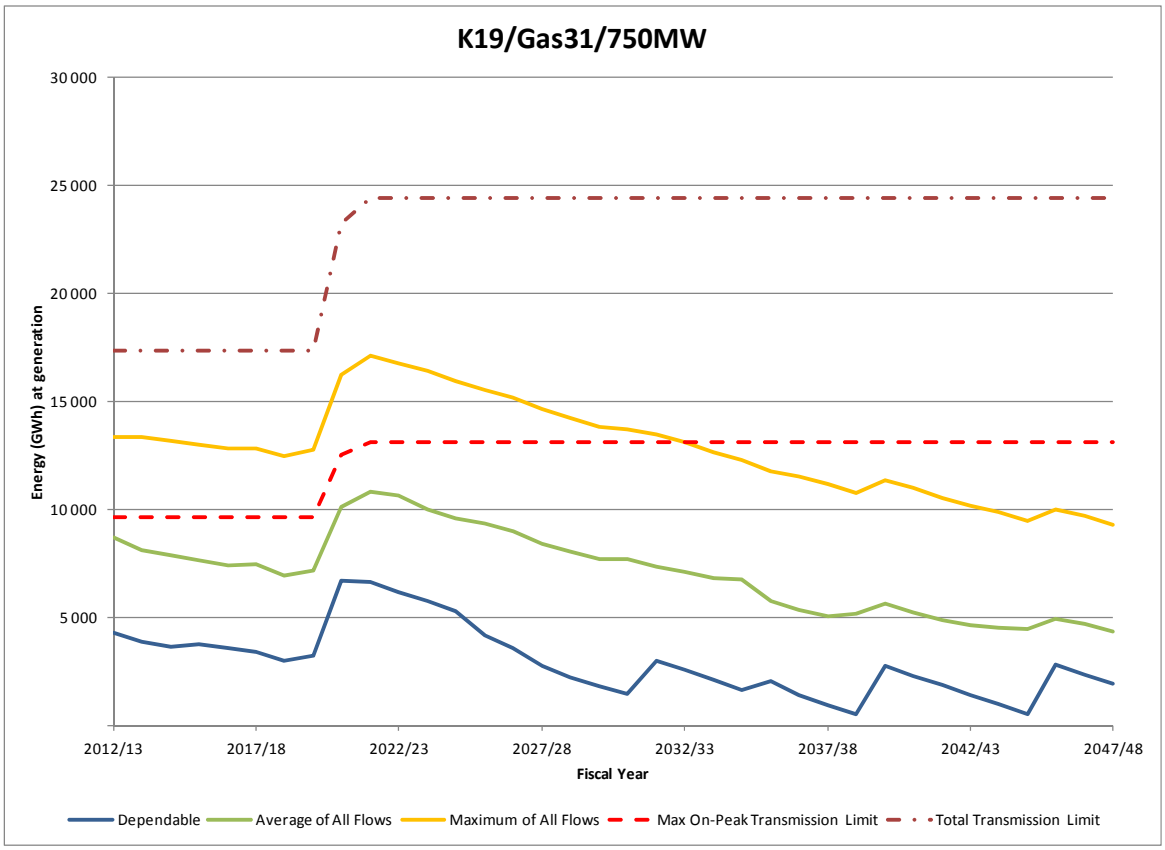
2


K19/Gas25/750MW (WPS Sale & Inv)
30 000
25 000
20 000
15 000
10 000
5 000
Energy (GWh) at generation
2012/13
2017/18
2022/23
2027/28
2032/33
2037/38
2042/43
2047/48
Fiscal Year
Dependable
Average of All Flows
Maximum of All Flows
Max On-Peak Transmission Limit
Total Transmission Limit

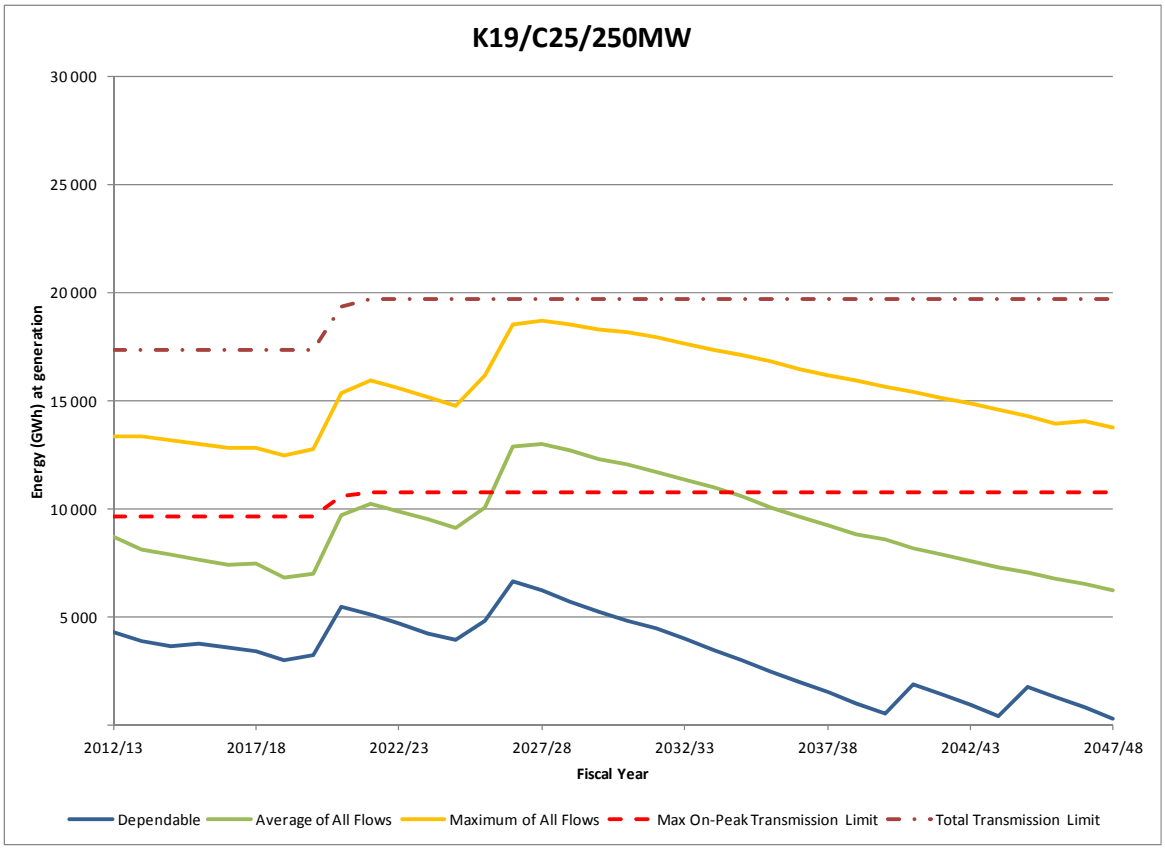
1


K19/C31/750MW
30 000
25 000
20 000
15 000
10 000
5 000
Energy (GWh) at generation
2012/13
2017/18
2022/23
2027/28
2032/33
2037/38
2042/43
2047/48
Fiscal Year
Dependable
Average of All Flows
Maximum of All Flows
Max On-Peak Transmission Limit
Total Transmission Limit

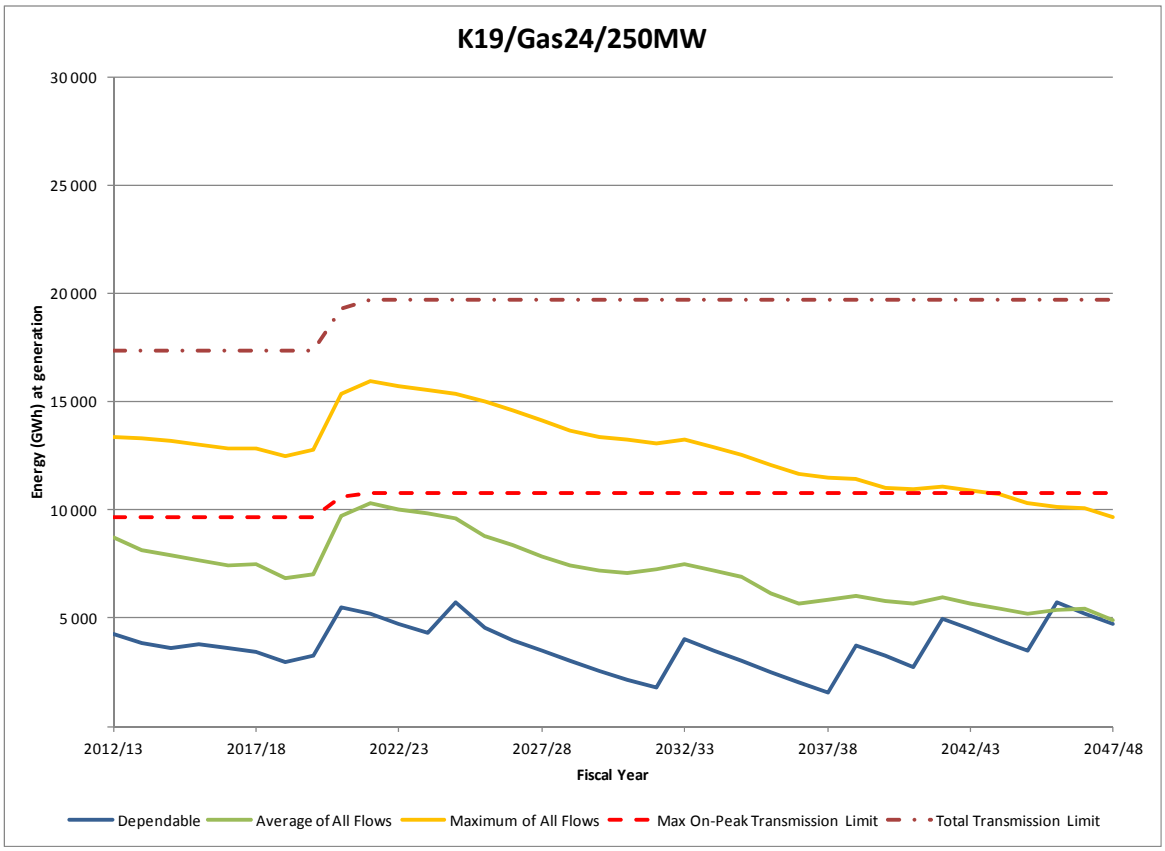
2


K19/Gas31/750MW
30 000
25 000
20 000
15 000
10 000
5 000
Energy (GWh) at generation
2012/13
2017/18
2022/23
2027/28
2032/33
2037/38
2042/43
2047/48
Fiscal Year
Dependable
Average of All Flows
Maximum of All Flows
Max On-Peak Transmission Limit
Total Transmission Limit

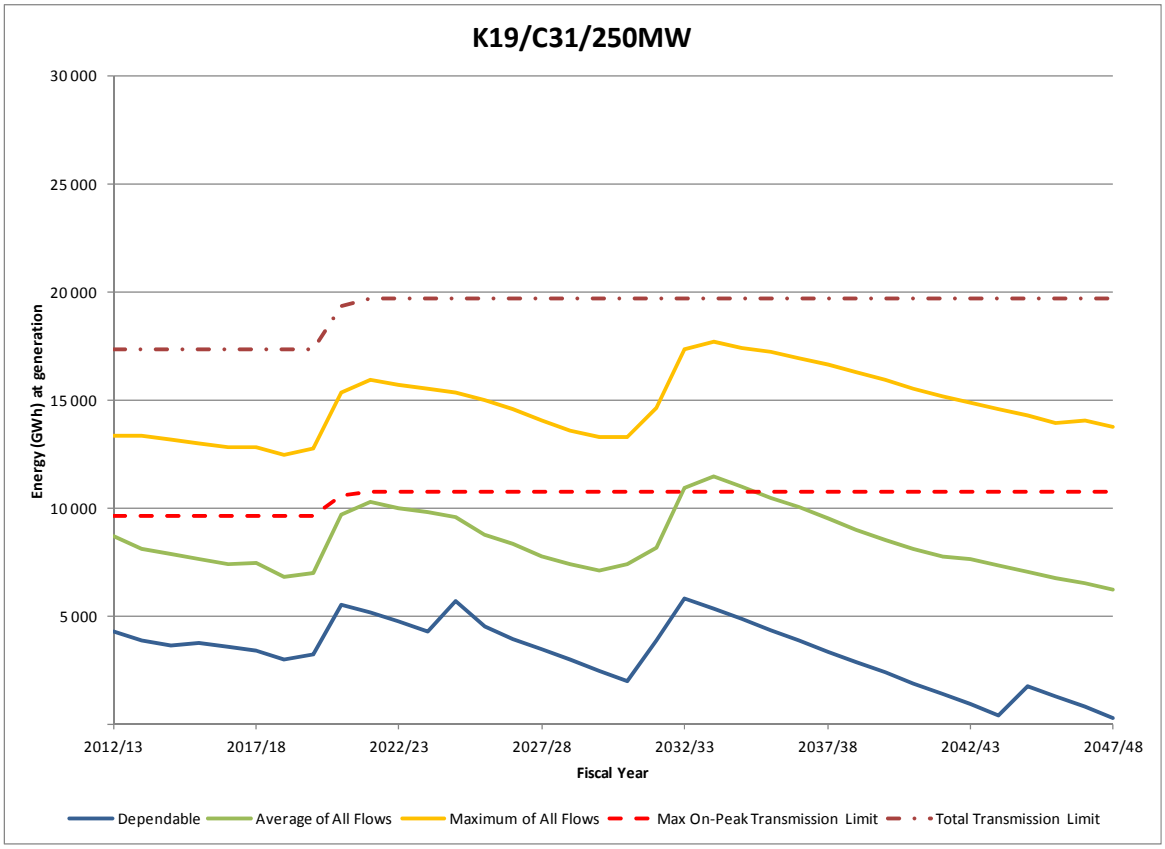
1


K19/C25/250MW
30 000
25 000
20 000
15 000
10 000
5 000
Energy (GWh) at generation
2012/13
2017/18
2022/23
2027/28
2032/33
2037/38
2042/43
2047/48
Fiscal Year
Dependable
Average of All Flows
Maximum of All Flows
Max On-Peak Transmission Limit
Total Transmission Limit

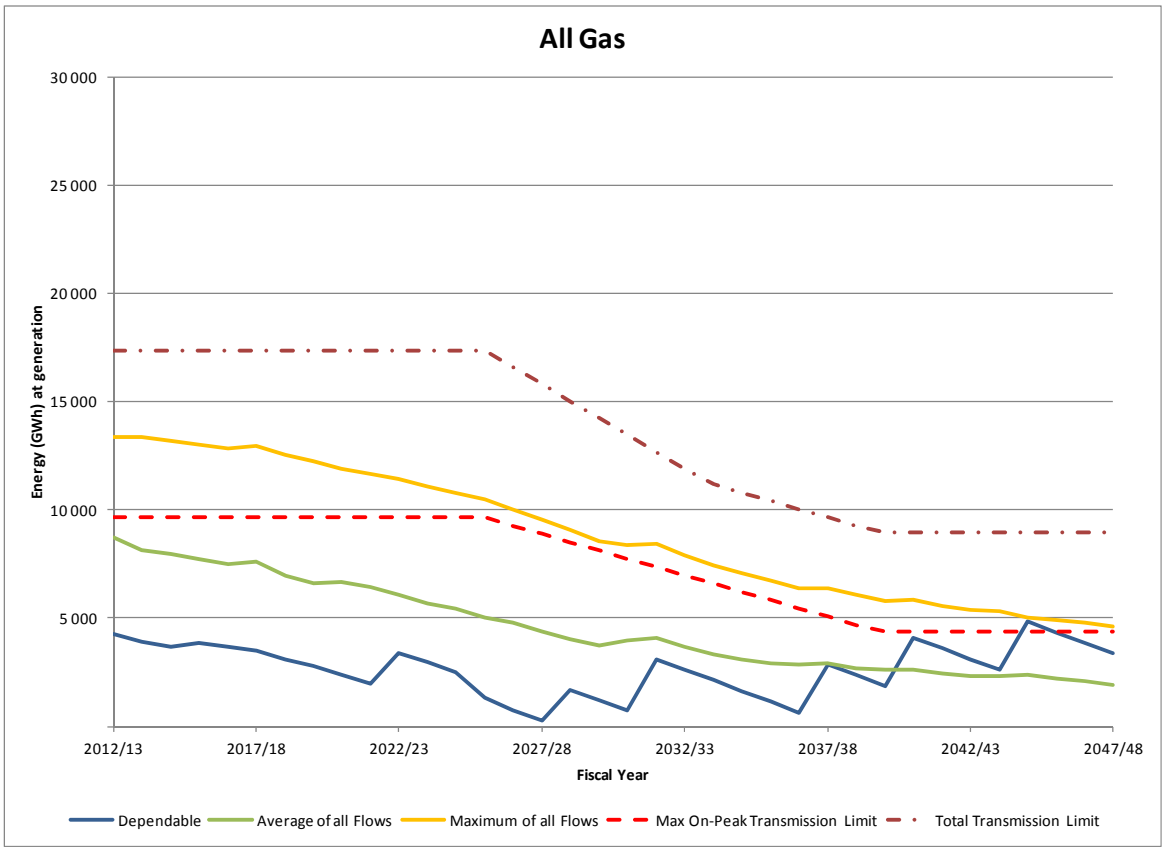
2


K19/Gas24/250MW
30 000
25 000
20 000
15 000
10 000
5 000
Energy (GWh) at generation
2012/13
2017/18
2022/23
2027/28
2032/33
2037/38
2042/43
2047/48
Fiscal Year
Dependable
Average of All Flows
Maximum of All Flows
Max On-Peak Transmission Limit
Total Transmission Limit

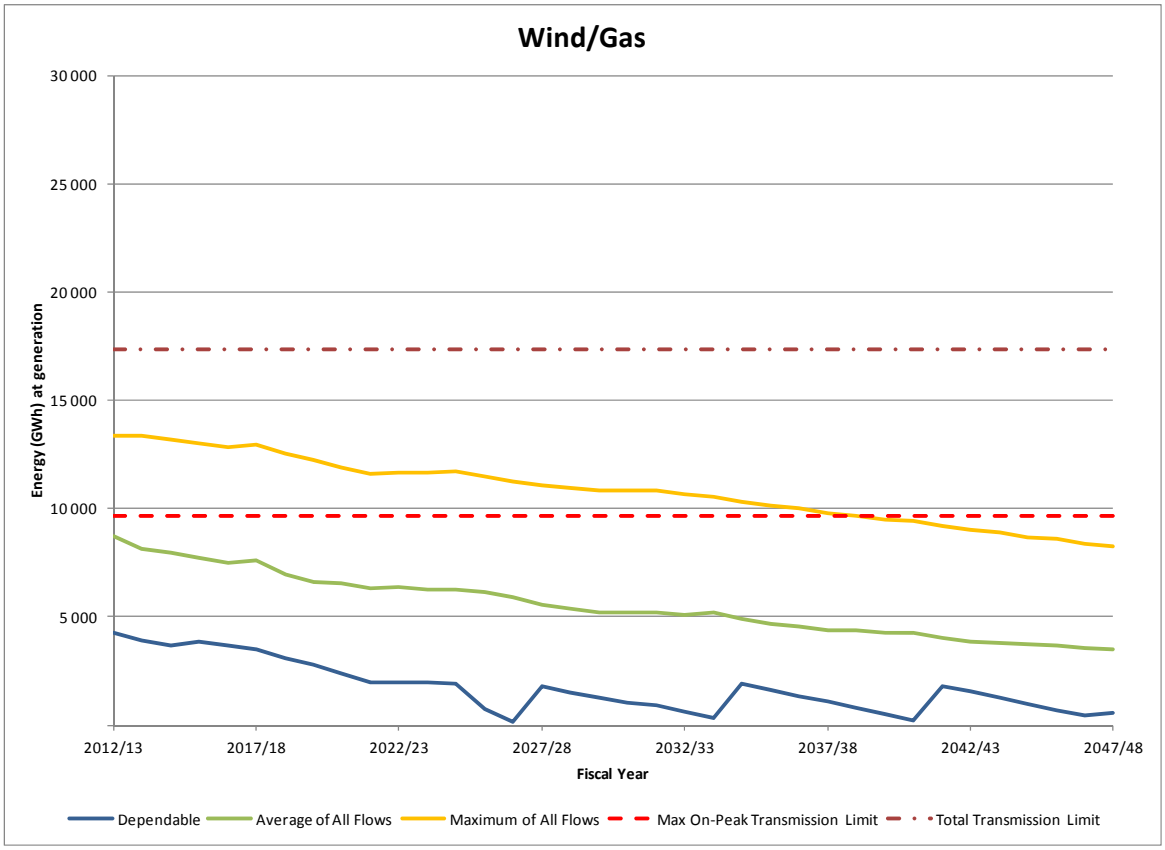
1


K19/C31/250MW
30 000
25 000
20 000
15 000
10 000
5 000
Energy (GWh) at generation
2012/13
2017/18
2022/23
2027/28
2032/33
2037/38
2042/43
2047/48
Fiscal Year
Dependable
Average of All Flows
Maximum of All Flows
Max On-Peak Transmission Limit
Total Transmission Limit

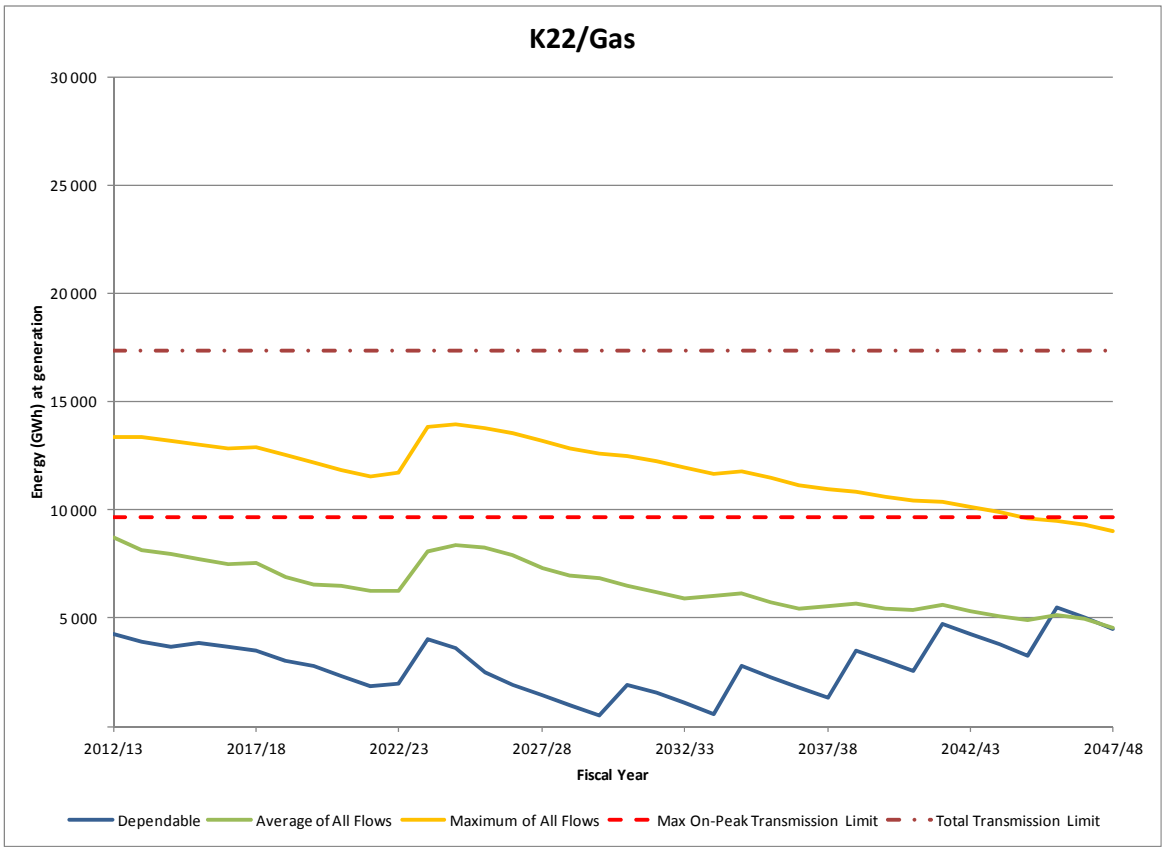
2


All Gas
30 000
25 000
20 000
15 000
10 000
5 000
Energy (GWh) at generation
2012/13
2017/18
2022/23
2027/28
2032/33
2037/38
2042/43
2047/48
Fiscal Year
Dependable
Average of all Flows
Maximum of all Flows
Max On-Peak Transmission Limit
Total Transmission Limit

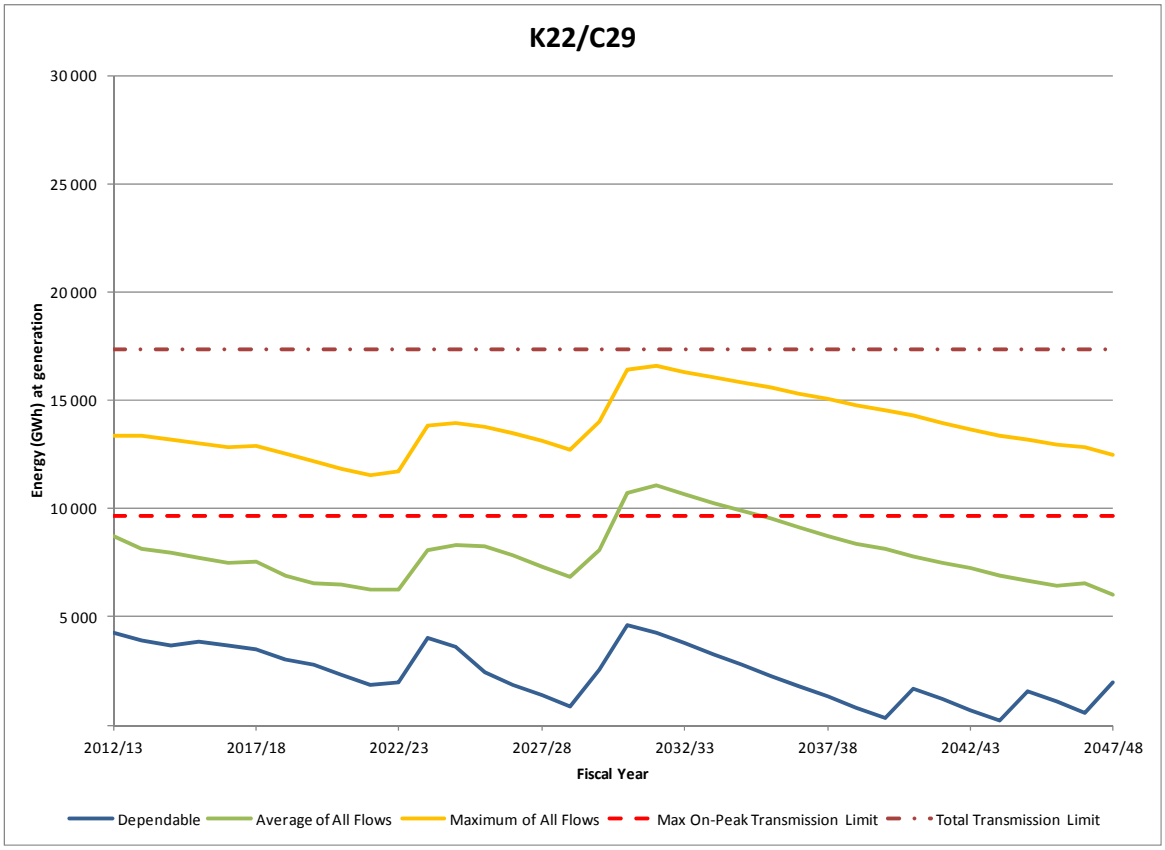
1


Wind/Gas
30 000
25 000
20 000
15 000
10 000
5 000
Energy (GWh) at generation
2012/13
2017/18
2022/23
2027/28
2032/33
2037/38
2042/43
2047/48
Fiscal Year
Dependable
Average of All Flows
Maximum of All Flows
Max On-Peak Transmission Limit
Total Transmission Limit

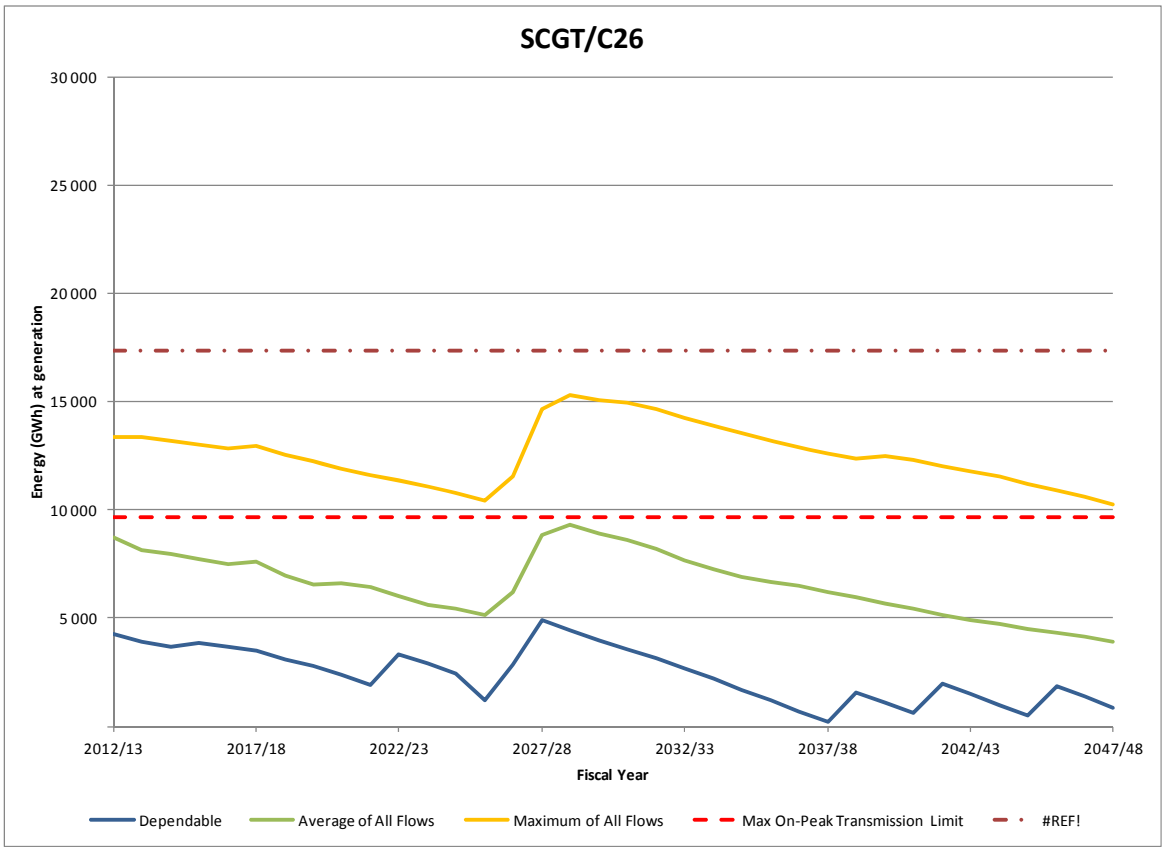
2


K22/Gas
30 000
25 000
20 000
15 000
10 000
5 000
Energy (GWh) at generation
2012/13
2017/18
2022/23
2027/28
2032/33
2037/38
2042/43
2047/48
Fiscal Year
Dependable
Average of All Flows
Maximum of All Flows
Max On-Peak Transmission Limit
Total Transmission Limit

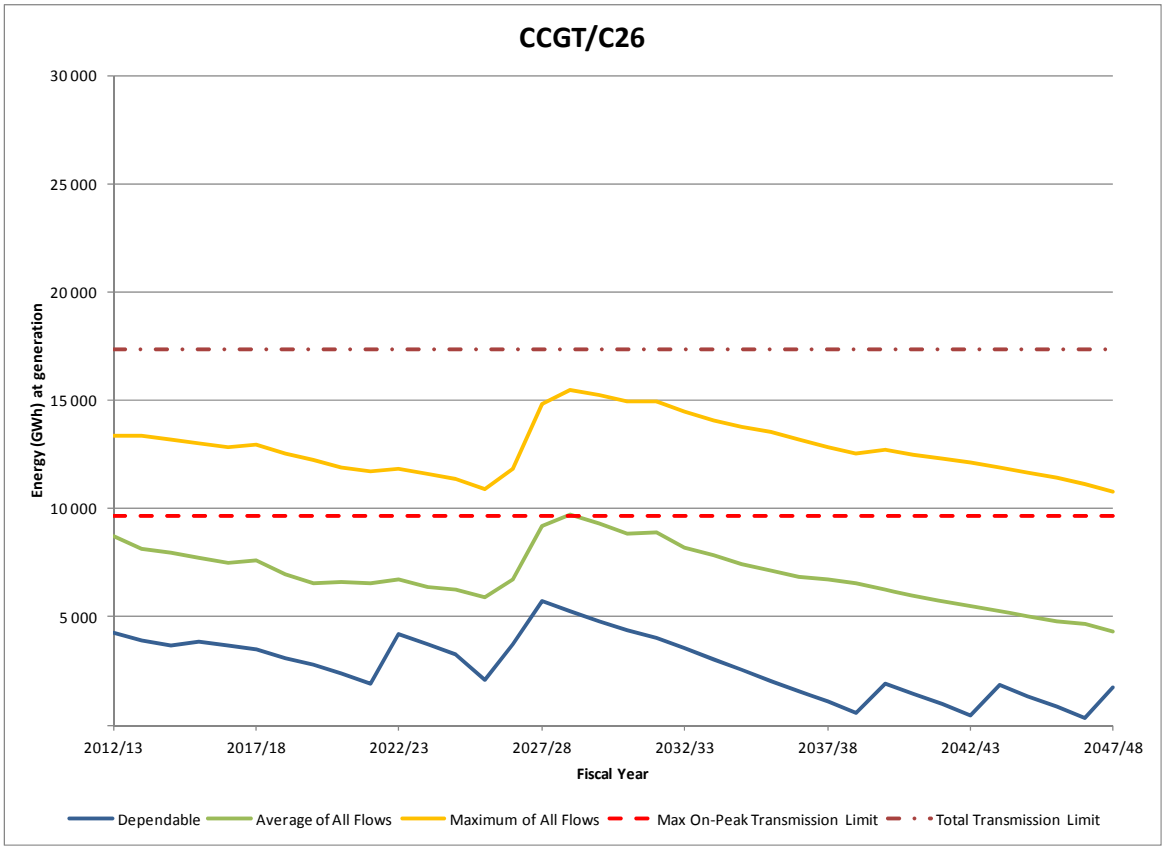
1


K22/C29
30 000
25 000
20 000
15 000
10 000
5 000
Energy (GWh) at generation
2012/13
2017/18
2022/23
2027/28
2032/33
2037/38
2042/43
2047/48
Fiscal Year
Dependable
Average of All Flows
Maximum of All Flows
Max On-Peak Transmission Limit
Total Transmission Limit

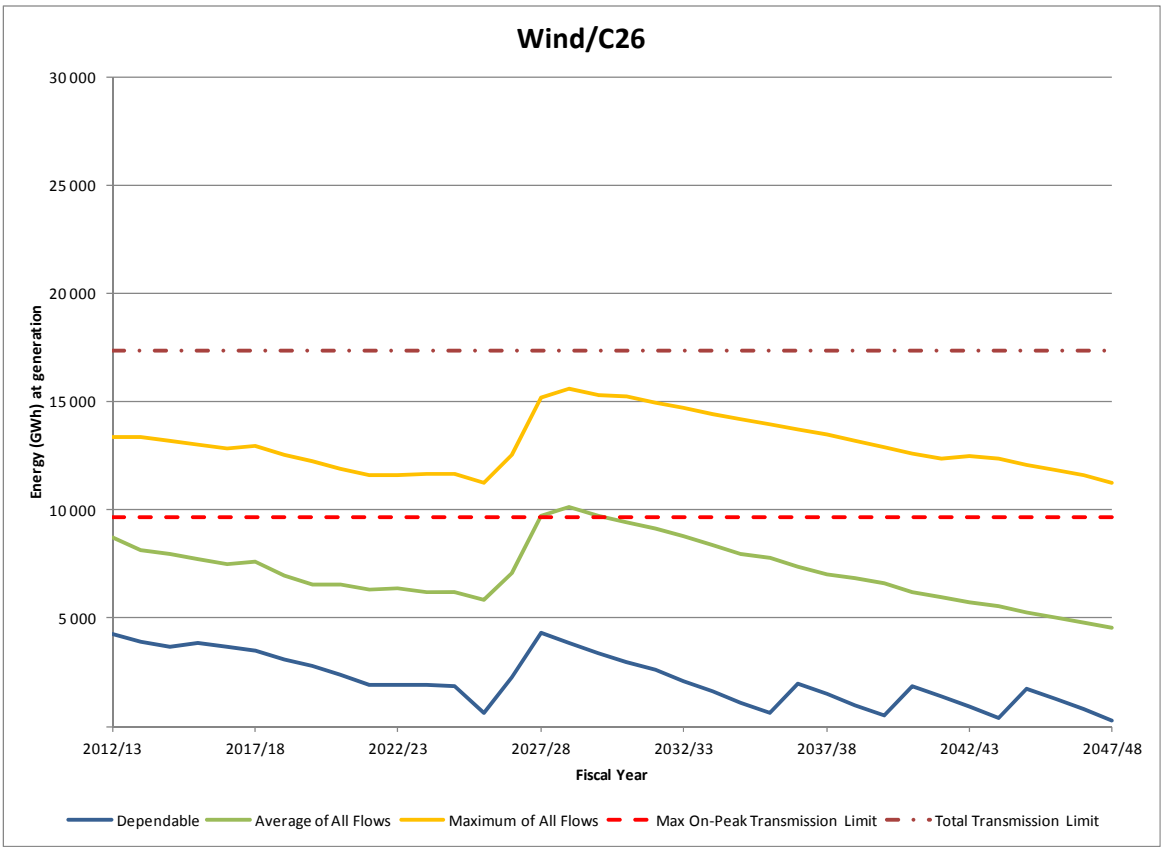
2


SCGT/C26
30 000
25 000
20 000
15 000
10 000
5 000
Energy (GWh) at generation
2012/13
2017/18
2022/23
2027/28
2032/33
2037/38
2042/43
2047/48
Fiscal Year
Dependable
Average of All Flows
Maximum of All Flows
Max On-Peak Transmission Limit
#REF!

1


CCGT/C26
30 000
25 000
20 000
15 000
10 000
5 000
Energy (GWh) at generation
2012/13
2017/18
2022/23
2027/28
2032/33
2037/38
2042/43
2047/48
Fiscal Year
Dependable
Average of All Flows
Maximum of All Flows
Max On-Peak Transmission Limit
Total Transmission Limit

2


Wind/C26
30 000
25 000
20 000
15 000
10 000
5 000
Energy (GWh) at generation
2012/13
2017/18
2022/23
2027/28
2032/33
2037/38
2042/43
2047/48
Fiscal Year
Dependable
Average of All Flows
Maximum of All Flows
Max On-Peak Transmission Limit
Total Transmission Limit

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.3.2; Page No.: 23

QUESTION:

Please discuss the relationship between the new transmission alternatives discussed at lines 20-21 and the new transmission interconnections (250 or 750 MW) set out in the current Application?

RESPONSE:

Two routing alternatives for the 750MW transmission line were considered: one route in western Minnesota and the other route in eastern Minnesota to a transmission terminal near Duluth owned by Minnesota Power.

Only one route is being considered for a 250MW transmission line: an eastern Minnesota route to a transmission terminal near Duluth owned by Minnesota Power.

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.5.2; Page No.: 28

QUESTION:

Please provide a schedule that sets out the annual capacity, on-peak energy and total energy values associated with each In the case of the WPS - Up to 300 MW please show the values for 100 MW and 300 MW.

RESPONSE:

The following table details the winter peak capacity obligations (@ generation) of the six contracts in Table 6.4 over the period 2013/14 through 2035/36. The annual energy values have not been provided as they are considered to be Confidential Commercially Sensitive Information.

Long Term Export Commitments
Contingent Upon New Hydro Development
Winter Peak Capacity (MW) @ generation

	NSP	MP		WPS		
	125 MW	250 MW	Energy Exchange*	100 MW Product A	100 MW Product B*	Up to 300 MW**
2013/14						
2014/15						119
2015/16						119
2016/17						119
2017/18						119
2018/19						119
2019/20						119
2020/21		275				119
2021/22	138	275		110		
2022/23	138	275		110		
2023/24	138	275		110		
2024/25	138	275		110		
2025/26		275		110		
2026/27		275		110		220
2027/28		275				330
2028/29		275				330
2029/30		275				330
2030/31		275				330
2031/32		275				330
2032/33		275				330
2033/34		275				330
2034/35		275				330
2035/36						330

*MP Energy Exchange Agreement and WPS 100 MW Product B do not have a capacity component.
**The WPS Sale of up to 300MW is under negotiation. The values shown represent the amounts assumed for planning purposes.

REFERENCE: Appendix 4.2 Manitoba Hydro Supply and Demand Tables; Section: 5; Page No.: 124

QUESTION:

Please provide a schedule that indicates how each of the existing and new contracts contributes to the capacity and energy values shown for each year in the "Contracted Exports" and "Proposed Exports" rows of the Preferred Development Plan - 2013 NFAT Update (Appendix 4.2, pages 124-127).

RESPONSE:

The following table details the winter peak capacity obligations for each existing and proposed contract for the Preferred Development Plan – 2013 NFAT Update. The annual energy values have not been provided as they are considered to be Confidential Commercially Sensitive Information.

Contracted & Proposed Exports
NFAT 2013 Update – Preferred Development Plan
Winter Peak Capacity (MW)

	Contracted Exports						Proposed Exports		
	Northern States Power			Minnesota Power		Wisconsin Public Service	Minnesota Power	Wisconsin Public Service	
	500 MW	375/325 MW	125 MW	50 MW	250 MW	100 MW	50 MW	108 MW	300 MW
2013/14	550			55					
2014/15	550			55				119	
2015/16		358					55	119	
2016/17		358					55	119	
2017/18		358					55	119	
2018/19		358					55	119	
2019/20		358					55	119	
2020/21		358			275			119	
2021/22		358	138		275	110			
2022/23		358	138		275	110			
2023/24		358	138		275	110			
2024/25		358	138		275	110			
2025/26					275	110			
2026/27					275	110			220
2027/28					275				330
2028/29					275				330
2029/30					275				330
2030/31					275				330
2031/32					275				330
2032/33					275				330
2033/34					275				330
2034/35					275				330
2035/36									330

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.5.3.2; Page No.: 30

QUESTION:

What transmission charges are associated with a contracted export sales by Manitoba Hydro and do they differ from the transmission charges associated with an opportunity export?

RESPONSE:

For long term contracted export sales, the cost of transmission service is generally borne by the customer who has the responsibility of reserving transmission service under the appropriate tariff. As a result Manitoba Hydro's customer pays the transmission service fees which contribute to the costs of operating and maintaining the transmission system.

For opportunity exports, Manitoba Hydro typically arranges for transmission service and pays the associated fees unless there is an arrangement in place where Manitoba has the right to use firm transmission service that is not needed at the time to deliver long term contracted energy.

For transmission service in Manitoba, Manitoba Hydro's customers take service under the Manitoba Hydro tariff to deliver energy from within Manitoba to the border. For transmission customers providing for load in MISO, customers are entitled to reserve transmission service under the Manitoba Hydro tariff at no cost as provided in the Manitoba Hydro MISO Coordination Agreement.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.0; Page No.: 1

PREAMBLE: The Chapter Overview states that `this chapter considers those technologies that are available for utility-scale generation`.

QUESTION:

Where in the submission are small scale generation options (e.g., customer-based solar installations) and commercial/industrial based load displacement generation options (e.g. Combined heat and power projects) discussed and considered as an option to meet future need?

RESPONSE:

Small scale generation options as described in the above Information Request would be captured under the Additional DSM row in the NFAT Business Case Chapter 7 Table 7.1 where these future options are screened.

Appendix 7.1 Sections 4.2, 4.4 and 4.5 provide additional discussion on industry trends and potential in Manitoba for solar rooftop, small scale photovoltaic and combined heat and power for commercial/industrial load displacement options.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.1.3; Page No.: 9

QUESTION:

Please provide the reports produced by IPSOS and Innovative Research Group regarding the results of the opinion polls conducted.

RESPONSE:

Materials from IPSOS are available at:

http://www.ipsos-mori.com/Assets/Docs/Polls/ipsos-global-advisor-nuclear-power-june-2011.pdf

and

http://www.ipsos-mori.com/researchpublications/researcharchive/2817/

Materials from the Innovative Research Group are available at:

http://www.cna.ca/wp-content/uploads/Polling_Deck_2011.pdf

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.1.4; Page No.: 10

QUESTION:

What discount rate is used to calculated the levelized cost values?

RESPONSE:

The information contained within Figure 7.2 is sourced from the U.S. Energy Information Administration's (EIA) "2013 Annual Energy Outlook Early Release". The discount rate utilized by the US EIA was a real cost of capital of 6.6%.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.1.2.1; Page No.: 16

QUESTION:

Based on Manitoba Hydro's generation planning criteria what is the maximum amount of imports that could be relied in 2023/24 and 2031/32 based on the export contracts and interconnections assumed under development plans #2, #4 and #14. Please show the supporting calculations.

RESPONSE:

The following table shows the maximum amount of import that can be considered as dependable energy for the specified years and development plans.

Generation Planning Criteria

Calculation of Dependable Energy Import (GW.h)

		1	2	3	4	5	6
Development Plan	fiscal year	Manitoba Net Load	Lake St. Joseph Export	Total Exports Net of Adverse Water	10% MB Load & Exports	Off-Peak Transmission Limit 700 MW, 47.62% CF	Maximum Import lesser of 4 or 5
					(1+2)*10%+(3-2)		
2	2023/24	28999	145	2219	4988	3068	3068
	2031/32	32632	145	145	3278	3068	3068
4	2023/24	28974	145	3963	6730	3291	3291
	2031/32	32632	145	1389	4522	3291	3291
14	2023/24	29054	145	3963	6738	4738	4738
	2031/32	32632	145	2882	6015	4738	4738

Notes:

1. Manitoba Net Load results from subtracting the expected savings from planned DSM programs from the electric load forecast.
2. Obligations under the Lake St. Joseph agreement are included in contracted exports in the Supply and Demand Dependable Energy tables. For this calculation, obligations under the Lake St. Joseph agreement are added to Manitoba Load.
3. Total Exports Net of Adverse Water is the sum of contracted and proposed exports net of adverse water as described on Page 13 of Appendix 9.3.
4. Off-Peak Transmission Limit represents the total energy which can be imported over the 700MW firm import capability of the existing US interconnection during the off-peak hours.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: 7.2; Page No.: 25

PREAMBLE: The submission indicates that the minimum time to the earliest in-service date for Notigi is 10 years (Chapter 7, page 27).

QUESTION:

What would be the minimum time to the earliest in-service date for the other "screened out" hydro resource options listed in Table 7.3?

RESPONSE:

The minimum time to the earliest in-service date for all hydroelectric resource options can be found in Table 7.3 under “Resource Lead Time”.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2.1; Page No.: 4

PREAMBLE: The submission indicates that in plans where Keeyask does not precede Conawapa, wind and natural gas-fired generation are the resource options considered to fill the resource "gap" prior to 2026/27.

QUESTION:

Why wouldn't imports be one of the potential resource options to fill this short term gap?

RESPONSE:

All of the development plans include imports up to the maximum limit as prescribed by the Energy Criterion of the Generation Planning Criteria which is described in Appendix 4. Additional imports above this limit are not assumed in order to comply with the Generation Planning Criteria.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2.2; Page No.: 7

QUESTION:

Is there/can there be a difference between the Manitoba Hydro's percentage ownership in a U.S. transmission line and its percentage investment? If yes, please explain how this would occur and what the implications would be for Manitoba Hydro's right to use the line.

RESPONSE:

There is no difference between percentage investment and percentage ownership. Manitoba Hydro acknowledges that its required contribution to the capital and operating costs of the line may exceed its percentage ownership.

There are no implications for Manitoba Hydro's right to use the line, which rights are determined independent of ownership.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2.2; Page No.: 7

QUESTION:

Are there financial, regulatory or other reasons why Manitoba Hydro does not want to own more than 49% of the interconnection facilities in the U.S.?

RESPONSE:

Manitoba Hydro has chosen to restrict its ownership level to a maximum of 49% so that it is not a majority owner in the line. Under Minnesota law, Minnesota Power has the right to 100% ownership of transmission in its service territory. Minnesota Power will be the majority owner and has allowed Manitoba Hydro to share in 49% of the ownership. It is beneficial for the project success and for Manitoba Hydro that Minnesota Power is championing the line development of the U.S. portion. It is the entity undertaking the U.S. Federal, Minnesota and MISO approval processes, route planning, community and landowner consultations, environmental studies, approvals for and acquisition of easements for the Right Of Way (Presidential Permit, State Certificate of Need and state routing permit) and that will be responsible for construction.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2.2; Page No.: 7

QUESTION:

Please explain how, under MISO's OATT, investment/ownership in a transmission line translates into "having the right to use".

RESPONSE:

Manitoba Hydro and its U.S. customers have made Transmission Service Requests (TSRs) for the right to use the electric power grid transmission capability to deliver the specified capacity and energy. MISO has indicated that granting the TSRs will require the construction of a new transmission interconnection and associated system improvements. For the new transmission interconnection to proceed to construction, MISO, Manitoba Hydro and the other transmission customers will sign a Facilities Construction Agreement (FCA). The FCA obligates MISO to grant service for the specified TSRs, and it is the granting of these TSRs which provides the “right to use” the transmission service created by the new transmission interconnection. It is not ownership in the transmission line but rather having received transmission service through the TSR process that provides the right to use the requested transmission.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2.3.1; Page No.: 9

QUESTION:

The submission makes reference to a 108 MW sale to WPS. Please confirm that this is considered part of the "Up to 300 MW WPS" sale set out in Table 6.4.

RESPONSE:

Confirmed.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2.3.1; Page No.: 10

QUESTION:

Please explain why the K19/C25/750 MW plan does not include the 108 MW WPS sales (per Table 8.2) from 2014 to 2021.

RESPONSE:

The WPS 108 MW Sale is part of the negotiation of potential sale agreements under the 300 MW Term Sheet. Development Plan K19/C25/750 MW does not include potential WPS sale agreements being negotiated under the 300 MW Term Sheet.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2.3.1; Page No.: 11

QUESTION:

With respect to K19/Gas 25/750 MW (WPS Sale & Inv), why was no consideration given to using imports (as opposed to natural gas generation) to meet the new requirements starting in 2025/26?

RESPONSE:

Development Plan K19/Gas 25/750MW (WPS Sale & Inv), or Plan 5 from Table 9.3, is described in Chapter 8, page 11 as "an alternative plan which allows for the comparison of the option of building natural gas-fired generation as an alternative to building Conawapa G.S. in 2025/26." This comparison was used to assess the economic implications of committing to a 750 MW interconnection but then not proceeding with Conawapa.

As such, the import assumptions were kept consistent with the Preferred Development Plan for the purpose of comparing the economic evaluation results of the two plans.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2.3.1; Page No.: 11

QUESTION:

With respect to K19/C31/750 MW, what limits the use of increased imports after 2031/32 and necessitates the need for other resources (i.e. Conawapa)?

RESPONSE:

The amount of imports that can be considered dependable energy is governed by the Generation Planning Criteria as described in Appendix 4.1. In this development plan additional resources are required in 2031/32 as the amount of imports included as dependable energy equals the quantity of export contracts in effect plus 10% of the Manitoba Load.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2.3.1; Page No.: 11

QUESTION:

With respect to K19/C31/750 MW, please explain why the Supply-Demand tables in Appendix 4.2 (page 48) do not show an increase in imports for the six year period up to 2031/32, contrary to the text on page 11 (lines 18-20).

RESPONSE:

The development plan referenced as Appendix 4.2 (page 48) is K19/C31/**250MW**, not K19/C31/750MW as stated in the question. Please refer to Appendix 4.2 (pages 32 to page 36) for the Winter Peak Capacity and Dependable Energy Supply and Demand Tables for K19/C31/750MW.

The additional import capability of the new 750 MW US Interconnection is shown on the Dependable Energy Supply and Demand Table as New Imports as well as an increase to Market Purchases beginning in 2020/21. Capacity purchases are shown on the Winter Peak Capacity Supply and Demand Table as Proposed Imports for the six year period beginning from 2025/26 to 2031/32.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2.3.2; Page No.: 13

QUESTION:

With respect to K19/C25/250 MW, please explain why the Supply-Demand tables in Appendix 4.2 (page 40) do not show an increase in imports for the year 2024/25 contrary to the text on page 13 (lines 5-7).

RESPONSE:

The increase in imports referred to in Section 8.2.3.2, page 13 lines 5 to 7 is a dependable energy import. Appendix 4.2 (page 40) as referenced in the above question is the Winter Peak Capacity Supply and Demand Table. The Dependable Energy Supply and Demand Table for K19/C25/250 MW is found on page 42 of Appendix 4.2.

The one year on-peak import is reflected as an increase to Market Purchases in 2024/25.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2.3.2; Page No.: 13

PREAMBLE: K19/C25/250 MW (page 13) requires a one year on-peak import contract in 2024/25.

QUESTION:

Please explain more fully why the one-year import contract is included in this case but is not required under the 750 MW interconnection plans (i.e. K19/C25/750 MW - with or without WPS Sale/Inv).

RESPONSE:

The one year on-peak import is required in 2024/25 in the K19/C25/250MW development plan due to the limited import capability of the 250MW interconnection of 50MW as opposed to the 750MW import capability of the 750MW interconnection. The 750MW interconnection allows for significantly more off-peak imports and therefore on-peak imports are not required prior to the earliest in-service date of Conawapa in plans with the 750MW interconnection.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2.3.2; Page No.: 13

QUESTION:

Does the same explanation apply to why Plan 4 with the 250 interconnection requires gas-fired generation in 2024 whereas Plan 5 does not require such generation until 2025?

RESPONSE:

Yes, as explained in CAC/MH I-096 the limited import capability of the 250MW interconnection results in the requirement for dependable energy resources in 2024/25 for Plan 4 (K19/Gas24/250MW). With the additional import capability of the 750MW interconnection, new dependable energy resources are not required until 2028/29 for Plan 5. New winter peak capacity resources are required in 2025/26 for both Plans 4 and 5. In summary, new natural gas-fired generation is required in 2024/25 for dependable energy in Plan 4, and in 2025/26 for winter peak capacity in Plan 5.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2.3.3; Page No.: 14

PREAMBLE: At Chapter 8, page 11 the Submission indicates that Keeyask provides sufficient energy to meet both MP and WPS contract requirements.

QUESTION:

Is it limits on Keeyask energy output or limits on interconnection export capability that restrict plans with Keeyask in 2022/23 to only serving the 100 MW WPS sale?

RESPONSE:

Development Plans with Keeyask in 2022/23 do not assume a new US interconnection. The MP 250 MW Sale, WPS 300 MW Sale and WPS 108 MW Sale are contingent upon a new US interconnection and therefore are not included in these plans.

The 125 MW NSP Sale is not contingent on a new US interconnection, however is not included in development plans with Keeyask in 2022/23 because Keeyask is not assumed to be in-service prior to the May 2021 start date of the sale and there is not sufficient exportable dependable surplus energy to serve this sale in these plans.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2.3.3; Page No.: 22

PREAMBLE: Chapter 6, page 28 - Table 6.4 includes a MP Energy Exchange contract which is not included in Chapter 8, Table 8.2

QUESTION:

Which of the plans included in Table 8.2 are assumed to include the MP Energy Exchange contract? As part of the response, please explain the rationale for it being included/excluded from each Plan.

RESPONSE:

The Minnesota Power Energy Exchange Agreement is assumed to be included in all development plans which include the MP 250 MW Sale. The MP 250 MW Sale is one of the sales that is contingent upon a new U.S. interconnection, therefore the MP Energy Exchange Agreement will be included in all of the plans which assume either a 250 MW or 750 MW interconnection.

For those development plans with a 250 MW interconnection, this contract will provide 50 MW of firm import capability over the contract term. For those development plans with a 750 MW interconnection, this contract will provide 250 MW of firm transmission service over the contract term.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2.3.3; Page No.: 22

QUESTION:

Please provide a revised version of Table 8.2 based on the 2013 Update assumptions set out in Chapter 12

RESPONSE:

The following table provides a summary of the sale agreements included in each development plan assessed for the 2013 Update evaluations.

NFAT 2013 UPDATE - SALE AGREEMENTS ASSOCIATED WITH EACH DEVELOPMENT PLAN

Development Plans	Sales Agreements					New US Interconnection Capability
	MP 250 MW	WPS 300 MW	WPS 108 MW	WPS 100 MW	NSP 125 MW	
K19/C26/750MW WPS Sale & Inv[6]	June 2020 to May 2035	June 2026 to May 2036	June 2014 to May 2021	June 2021 to May 2027	May 2021 to Apr 2025	750 MW import/ 750 MW export
K19/C33/750MW	June 2020 to May 2035	No	No	June 2021 to May 2027	May 2021 to Apr 2025	750 MW import/ 750 MW export
K19/Gas30/250MW	June 2020 to May 2035	No	No	June 2021 to May 2027	May 2021 to Apr 2025	750 MW import/ 750 MW export
K23/Gas	No	No	No	No	No	None
All Gas	No	No	No	No	No	None

[6] Inv refers to WPS investment in the U.S. portion of the 750 MW interconnection facilities.

REFERENCE: Chapter 8: Determination and Description of Development Plans; Section: 8.2.3.3; Page No.: 22

PREAMBLE: During the September 5-6 Technical Conference Manitoba Hydro indicated that WPS was still interested in pursuing the 300 MW contract but was not interested in investing in the 750 MW interconnection.

QUESTION:

Please confirm that this does not impact the "sales agreements" associated with each of the development plans as set out in Table 8.2.

RESPONSE:

Confirmed.

Please note that the NFAT analysis was based on the WPS Term Sheet which continues to be under negotiation. The WPS sale agreements are not final until they have been executed. Since the potential agreements with WPS continue to be under discussion, the K19/C25/750MW development plan was included in the business case analysis as a comparison to the K19/C25/750MW (WPS Sale & Inv) Development Plan should the potential sales to WPS not materialize.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.1; Page No.: 2

PREAMBLE: Chapter 9, page 1 states that "Section 9.3.2 provides the incremental NPVs to Manitoba Hydro for the reference scenario"

QUESTION:

The explanation of the economic evaluation perspective on page 2 is slightly different and suggests it is from "the overall project perspective" as opposed to a Manitoba Hydro perspective. Please clarify.

RESPONSE*:*

In the context of the economic evaluation, “the overall project perspective” is also the Manitoba Hydro perspective referenced in Chapter 9 Page 1, lines 15 to 17. Chapter 9 Page 2, lines 17 to 23, further explain that “the economic evaluation presents the incremental economic impact. . . from the overall project perspective without accounting for any aboriginal income sharing”. It is the financial evaluations that consider benefits to rate payers net of the aboriginal income sharing.

Chapter 9 Pages 1 and 2 are also consistent with the discussion “Aboriginal Income Sharing” on page 8, chapter 14. The economic evaluations consider the costs and benefits of proceeding with different selections of projects in the plans. The economic analysis includes the costs and benefits Manitoba Hydro experiences in proceeding with the projects. For greater clarity, these include for example process costs associated with the participating First Nation community consultations, negotiations, joint studies and adverse effects arrangements as these are payments included in project capital costs. The economic analysis does not include any equity contributions from the participating First Nations and the income sharing. These are not project capital costs and are accounted for in the financial analyses.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.1; Page No.: 4

QUESTION:

Please provide Manitoba Hydro's Hurdle Rate Policy as filed with the CEC at the time of its review of the Need for and Alternatives to the Wuskwatim Project and indicate if there have been any changes or updates to the policy.

RESPONSE:

Manitoba Hydro's corporate policy, filed with the CEC in November 2003, is attached. Since that time, the policy was updated to recognize that the selection of the hurdle rate depends upon the degree to which risk has already been accounted for in the project cost estimates and whether there has been comprehensive risk analysis.

CAC/MSOS/MH/NCN I – NFAAT – 3a

REFERENCE: APRIL 2003 NFAAT SUBMISSION, OVERVIEW, PAGE 6, LINES 1-12

QUESTION:

a) Please provide any policies or other documentation Manitoba Hydro has prepared that describe how projects being considered by the Corporation are to be evaluated and, in particular, how they are to be classified as between low, medium and high risk.

ANSWER:

Please also refer to PCN/NCNI – NFAAT 12a for provision of policies directing preparation of power resource planning. The text below provides the corporate policy on economic evaluations for capital decisions.

HURDLE RATE POLICY

Background

Capital expenditures undertaken by Manitoba Hydro are for reliability, safety, contractual, regulatory and environmental obligations and the general obligation to serve, or are undertaken for economic reasons. In order to evaluate the economics of a project, Manitoba Hydro utilizes business case principles involving the techniques of discounted cash flow ("DCF"), net present value ("NPV") or internal rate of return ("IRR").

Two forms of economic analysis are generally used in investment decisions. The choice of which one to use is made by the analyst based on the type of project. The two forms are as follows:

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1. Cost/benefit analysis is used to determine if a project is economically viable. If the benefits of the project are greater than the costs over the analysis period, considering the time value of money, the project is economically viable and has a positive cost/benefit.

2. Least cost analysis is used to determine the least cost approach given a number of available alternatives. The costs of each alternative are compared on a consistent basis over the analysis period, taking into account the time value of money, in an effort to determine the least cost alternative.

In these analyses, Manitoba Hydro uses risk adjusted hurdle rates to discount future revenues and costs and determine whether the resulting NPV is positive. A hurdle rate is defined as the minimum expected rate of return that would be acceptable to justify making the investment. Generally, the starting point for development of a hurdle rate is the weighted average cost of capital ("WACC") – i.e., the company's overall cost of financing. Depending on the type of project to be evaluated, a further risk premium can be added beyond that which is incorporated in the WACC to recognize additional uncertainty in future cash flows.

Manitoba Hydro's overall WACC is calculated using the cost of debt and the imputed rate for equity which are then weighted by Manitoba Hydro's target capital structure of 75% debt and 25% equity. The cost of debt is the forecast interest rate on the Government of Canada long term (>10 year) bond yield, plus provincial-federal borrowing spread and the provincial guarantee fee. The imputed cost of equity is calculated based on the fact that regulated investor owned utilities receive a regulated return on equity which is approximately 3% higher than the current market cost of new long term debt.

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Therefore, Manitoba Hydro's WACC is calculated as follows:

WACC = (Cost of Debt x 75 %) + (Imputed Cost of Equity x 25 %)

WACC is usually used to assess investments in Manitoba Hydro's core business mix – i.e. generation, transmission and distribution for domestic markets along with the types of export business in which the Corporation has historically engaged. If a project falls outside of these core activities or has an unusual degree of risk, then the hurdle rate would be greater than WACC.

The selection of an appropriate discount rate depends on the risk associated with the cash flow projections. If future anticipated cash flows for a project have already been adjusted to reflect a degree of uncertainty, then this would tend to reduce the level of risk premium incorporated in the applicable hurdle rate.

Hurdle rates are applied to arrive at a quantitative determination of a project's relative acceptability. However, the economic evaluation of a project or investment is only one component in determining whether to proceed. Other factors such as ensuring the safety and reliability of the system, customer service or operational efficiency are also considered. The weighting of these components may vary for each project or investment. Therefore, a project with a positive or negative NPV may or may not be approved depending on the significance of these other components.

Policy for Application of Hurdle Rates for Use in Project Evaluation

As a general guideline, the company provides benchmark hurdle rates classified as low, medium and high risk investments or projects. These benchmark rates (in real terms) are demarcated by 5.98%, 10% and 15%+ for low, medium and high risk projects, respectively. In practice, each cash flow component will have varying levels of risk specific to the nature of that project. Therefore the risk classification of certain projects may not precisely equal one of the benchmark categories but instead fall within the range of the guideline rates provided.

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Following is a description of these guideline categories together with examples. The examples are not intended to be all inclusive but rather are illustrative indications. As noted above, the hurdle rate is partly dependent on the degree to which risk has been recognized in the cash flow projections for the specific investment and is therefore not necessarily based on the type of project. For assistance in determining the appropriate risk adjusted rate for any project, departments should contact the Economic Analysis Department, in the Treasury & Business Analysis Division of the Finance and Administration Business Unit. Where a hurdle rate other than at the top end of the range in each of the following risk categories is selected, Executive approval is required.

Low Risk (5.98%)

A project with a low level of risk is defined as one which belongs in Manitoba Hydro's core business mix – i.e., generation, transmission and distribution for domestic markets along with the types of export business in which the Corporation has historically engaged. Such projects would be evaluated using WACC – i.e. a real discount / hurdle rate of 5.98%.

General examples include, but are not limited to:

- Projects required to meet safety, environmental or regulatory standards
- Mandatory expenditures to maintain operational integrity of the system.
- Cost minimization / operational efficiency projects
- Power resource projects (e.g., demand side management, supply side enhancements and new generation) undertaken mainly in order to meet

Manitoba Hydro's obligation to serve domestic load or exports under existing contracts.

Low to Medium Risk (greater than 5.98% to 10%)

A project that would be classified as ranging from low to medium risk is defined as one which belongs in Manitoba Hydro's core business mix (as defined for low risk), but which presents additional challenges and uncertainties. To recognize this exposure, a real discount / hurdle rate in the range of greater than 5.98% up to 10.0% is required.

General examples include, but are not limited to:

- Certain customer service and joint ventures for utility services
- T&D power loss reduction projects
- Manitoba Hydro International projects with guaranteed contracts.
- Power resource projects (e.g., demand side management, supply side enhancements and new generation) with typical challenges and uncertainties.

Medium to High Risk (greater than 10% to 15.0%+)

A project with a medium to high level of risk is defined as one which does not belong in Manitoba Hydro's core business mix or which presents significant additional challenges and uncertainties. To recognize this exposure, a real discount /hurdle rate in the range of greater than 10.0% to 15.0%+ is required.

General examples include, but are not limited to:

- Certain projects with highly uncertain cash flows which may be offered to Manitoba Hydro International

- Major initiatives to gain new sources of revenue
- Investments in new technology not directly related to core business
- Power resource projects (e.g., demand side management, supply side enhancements and new generation) with atypically high challenges and uncertainties.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.2; Page No.: 3

PREAMBLE: Appendix 9.3, page 91 (Table 001) does not include any capital costs for Keeyask beyond the initial in-service capital costs.

QUESTION:

Why are there no capital costs included in the analysis for Keeyask after the in-service date in order to account for replacement of equipment over the study period?

RESPONSE:

Costs associated with replacement of equipment for Keeyask G.S. after the in-service date are included in the fixed operating and maintenance cash flow as provided in the Fixed O&M cash flow column in Table 001 of Appendix 9.3.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.4; Page No.: 7

PREAMBLE: Appendix 11.2 (page 1) sets out the forecast interest rates for the Reference case.

QUESTION:

Please explain how the 6.3% cost of debt was derived from the interest rate forecast set out in Appendix 11.2

RESPONSE:

Table 2 in the response to PUB/MH I-0065 provides Manitoba Hydro's forecast of Canadian 10 Year+ Bond Yield Rates based on the fall review of the 2012 Economic Outlook.

The reference case long-term interest rate, as shown in Appendix 11.2, was calculated by adding the appropriate Manitoba/Canada credit spread to the Canadian 10 year+ bond yield rate and a provincial debt guarantee fee as follows:

	Canadian 10 Year+ Bond Yield	10 Year+ Credit Spread	Guarantee Fee	MH Canadian 10 Year+ Long Term Interest Rate
2018/19+	4.65%	0.65%	1.00%	6.30%

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.4; Page No.: 7

QUESTION:

What is the basis for the three-percentage point premium assigned to the cost of equity?

RESPONSE:

Please see the response to PUB/MH I-151c.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1.1; Page No.: 10

QUESTION:

Is it the On-Peak All-in Product price projection that is used for on-peak opportunity sales made out of surplus (as opposed to dependable) energy? If not, what price forecast is used for on-peak opportunity sales?

RESPONSE:

Yes. The On-Peak All-in Product is the basis for pricing on-peak opportunity sales of surplus energy. This product includes energy based delivery for the 5x16 on-peak period and the necessary associated capacity.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1.1; Page No.: 10

PREAMBLE: In Appendix3.1 (page 33) the Brattle Group provides forecast for i) All In Price; ii) On-Peak Energy; iii) All Hours Energy and iv) Off-Peak Energy.

QUESTION:

Please indicate how the four forecasts provided by the Brattle Group relate to the three products described in Appendix 9.3 at page 10.

RESPONSE:

The four forecasts provided by The Brattle Group are simply different ways to present the output from Brattle's production costing and capacity expansion models. Brattle's production costing model provides an energy price corresponding aggregated to "On-Peak Energy" and "Off-Peak Energy" and averaged over annual time horizons. Those two energy products are averaged on a weighted basis over the year to produce an "All Hours Energy" price. It should be noted that these energy prices are representative of the MISO energy market prices. A capacity expansion model provides anticipated costs and type of new generation when it is needed and provides the value of capacity for new resource additions. This value of capacity is provided in dollars per KW-year format and then distributed evenly over the entire 8760 hours in a non-leap year to produce Brattle's "All-In Price".

Manitoba Hydro's "Off-Peak Energy" product is directly comparable to Brattle's similarly named product. Manitoba Hydro's "On-Peak All In" product is the On-Peak energy price with value of capacity distributed over the On-Peak period, rather than all hours as shown in the Brattle work. It would be comparable to the expected value for a bundled bilateral sale of 5 x 16 On-Peak energy and capacity. The "On-Peak Long Term Dependable" product is a derivative of "On-Peak All In" product. It is technically the same product as the "On-Peak All In" product (5 x 16

On-Peak energy and capacity), but with a duration of at least five years and with the energy sourced from Manitoba Hydro's dependable energy resources, and priced at a small premium over the "On-Peak All In" product. The premium is deemed to represent an additional amount the purchaser is willing to pay for price and volume certainty over the long-term as well as to represent Manitoba Hydro's experience and ability to attain a higher value for a long-term, low carbon product sourced from dependable resources.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1.2; Page No.: 11

QUESTION:

For each of the three products described on page 10 please provide an indication as to the range of Reference case prices received for the years 2019/20; 2023/24 and 2031/32 by indicating the percentage difference between the lowest and highest of the five forecasts obtained from the independent consultants.

RESPONSE:

Responding to this information request would require the release of Commercially Sensitive Information. The specific details of the electricity price forecasts used by Manitoba Hydro are confidential since public release could harm Manitoba Hydro in negotiation of contracts for export sales.

In terms of a general indication of the range in reference case prices as provided by the electricity export price forecasters, the range in the 2019/20 timeframe is broader than it is in the 2023/24 timeframe. The range is somewhat narrower in the 2031/32 timeframe than it is in the 2023/24 timeframe. In addition, there is more variability in the range for the On-Peak All-In and Long-Term Dependable products across the three timeframes than for the Off-Peak energy product.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.6; Page No.: 17

QUESTION:

Please reconcile the long-term contracts contingent upon development as set out in Appendix 9.3, Table 1.5 (page 17) with the Sales Agreements identified in Table 8.2 of Chapter 8 of the Main Business Case.

RESPONSE:

The following table shows the long-term contracts contingent upon new development as outlined in Table 1.5 of Appendix 9.3 with the corresponding sales agreements identified in Table 8.2 of Chapter 8.

Long-Term Export Contracts				
Appendix 9.3 Table 1.5			Chapter 8 Table 8.2	
Customer	**Contract Name**	**Term**	**Sales Agreements**	**Term**
Minnesota Power	MP 250	June 2020 to May 2035	250 MW MP	June 2020 to May 2035
Northern States Power	NSP 125	May 2021 to April 2025	125 MW NSP	May 2021 to April 2025
Wisconsin Public Service	WPS 100 Product A	June 2021 to May 2027[2]	100 MW WPS	June 2021 to May 2025
	WPS 100 Product B[1]	June 2025 to May 2029	Not Included	–
	WPS Up to 300 MW	June 2014 to May 2040[3]	108 MW WPS	June 2014 to May 2021
			300 MW WPS	June 2026 to May 2036

Notes:

[1] WPS 100 Product B has no dependable energy or capacity obligation and therefore is not included in the Supply and Demand Tables or in Table 8.2. WPS 100 Product B has an energy obligation under median or better water flow conditions.

[2] Manitoba Hydro may extend the May 2025 end date of Product A by up to 2 years. In such case, the start date of Product B is delayed by up to 2 years.

[3] The WPS Up to 300 MW agreement is under negotiation. For analysis purposes it was assumed that the 108 MW and 300 MW sales have dependable energy and capacity requirements for their specified terms. Additional energy obligations under median or better flow conditions were also assumed that would not impact the supply and demand tables during the proposed agreement term and are not reflected in Table 8.2.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.8; Page No.: 27

QUESTION:

Are the marginal costs described in Section 1.8 used at all in the economic evaluation described in Chapter 9? If so, where and how are they used?

RESPONSE:

The marginal costs described in Section 1.8 were not used at all in the economic evaluation described in Chapter 9.

As stated in Chapter 9, page 4, "Manitoba Hydro's approach to economic evaluation is consistent with standard economic analysis methodology." The economic evaluation in Chapter 9 uses development plan comparisons and discounted cash-flow analysis to compare the cash flows of development plans which measure the incremental costs and benefits associated with one plan relative to another.

Appendix 9.3 Section 1.8 describes the marginal cost methodology that would apply to a modest uniform load change and is the methodology used to determine the marginal costs that are provided for evaluation of Manitoba Hydro's DSM programs.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.9; Page No.: 31

QUESTION:

Please reconcile the assumption that 80% of total incremental investment is through new-long term debt with the fact the financial evaluation assume a return to a 75% debt ratio by 2031/32 (per Chapter 11, page 4).

RESPONSE:

For the economic analysis, an assumption was made that 80% of the capital costs will be debt financed. This simplifying assumption recognizes that debt ratios will be higher than the 75% target in the early years of investment before returning to levels of 75% by 2031/32. See MIPUG/MH I-028g.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.9; Page No.: 31

QUESTION:

Is it not possible to use the financial analysis from Chapter 11 to determine the increase in new debt relative to the incremental capital investment for each development plan? If not, explain why not.

RESPONSE:

The financial evaluation based on an integrated financial forecast is not intended as incremental analysis. As outlined in the response to CAC/MH I-111, 80% of the capital costs were assumed to be debt financed for the purposes of the debt guarantee fee calculation in the economic analysis.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.9; Page No.: 31

QUESTION:

If yes, please do so for Plans #2, #4 and #14

RESPONSE:

Debt guarantee fees for Plans 2, 4, and 14 were calculated based on debt levels described in Chapter 11. These debt guarantee fees are used in the Multiple Accounts Cost Benefit Analysis, and presented in Table 13.3, Chapter 13, Section 13.3.3, page 29.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 3.2.1; Page No.: 87

PREAMBLE: Appendix 9.3 (page 87) states "Gross revenue does not include domestic revenue as it is common to all development plans".

QUESTION:

Please confirm that, to the extent the assumed rate increases vary by plan, domestic revenues will vary by plan.

RESPONSE:

Not confirmed for the economic evaluations.

Manitoba Hydro uses development plan comparisons and discounted cash-flow analysis to compare the cash flows of development plans. When evaluating and choosing among alternative development plans, the appropriate measure is the incremental costs and benefits associated with one plan relative to another. This means that costs and benefits that are common to all development plans are not included in the analysis as these values are the same in each development plan. Consistent with this methodology and from an economic perspective, there are no rate changes, and domestic revenue is assumed to remain fixed for all development plans and therefore is common to all development plans. Any economic return (or loss) will be indicative of the funds available to subsidize domestic rates (or required domestic rate increases). It is the financial analysis that will focus on the comparative impact on future customer rates and Manitoba Hydro's comparative exposure to financial risk of the various development plans.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 3.2.1; Page No.: 87

PREAMBLE: Appendix 9.3 (page 87) states "Gross revenue does not include domestic revenue as it is common to all development plans"

QUESTION:

If confirmed, please reconcile with the statement in the preamble and explain why variations in domestic revenues are not incorporated in the analysis similar to variations in export revenues by plan.

RESPONSE:

Please see Manitoba Hydro's response to CAC/MH I-113a.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 3.2.2; Page No.: 88

QUESTION:

Please provide a 20-year history of water rental fees charged by the province.

RESPONSE:

The table below provides water rentals paid by Manitoba Hydro. These amounts exclude water rentals assessed to Winnipeg Hydro prior its purchase by Manitoba Hydro in 2002. Also note that the 2012/13 assessment includes water rentals assessed to the Wuskwatim Power Limited Partnership.

WATER RENTALS ASSESSED TO MANITOBA HYDRO (INCLUDING WUSKWATIM POWER LIMITED PARTNERSHIP).

Fiscal Year	Water Rental Fees
1993-1994	$ 42,652,090.88
1994-1995	$ 43,862,046.56
1995-1996	$ 45,817,600.01
1996-1997	$ 50,016,042.11
1997-1998	$ 53,427,855.14
1998-1999	$ 46,253,229.35
1999-2000	$ 46,186,661.65
2000-2001	$ 50,801,545.54
2001-2002	$ 106,823,339.24
2002-2003	$ 95,149,600.84
2003-2004	$ 64,511,478.28
2004-2005	$ 104,072,964.32
2005-2006	$ 124,409,993.32
2006-2007	$ 105,664,304.80
2007-2008	$ 116,652,081.48
2008-2009	$ 114,549,063.36
2009-2010	$ 114,016,964.68
2010-2011	$ 114,122,275.08
2011-2012	$ 110,840,270.68
2012-2013	$ 110,427,160.34

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Page No.: 91

QUESTION:

For each of Table 001 through Table 405, please provide the Table in a working Excel file with the formulae intact and unprotected.

RESPONSE:

Please see the attached excel file for Tables 001 to 405, accessible electronically at www.hydro.mb.ca/projects/development_plan/bc_documents/CAC_116_attachment.xlsx

This attachment is provided in electronic form only.

This file does not include any formulas as Table 001 through Table 405 were developed for presentation purposes and include inputs from other sources.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Page No.: 523

QUESTION:

For each of Table 433 through Table 444, please provide the Table in a working Excel file with the formulae intact and unprotected.

RESPONSE:

Please see the attached excel file for Tables 433 to 444, accessible electronically at www.hydro.mb.ca/projects/development_plan/bc_documents/CAC_116_attachment.xlsx

This attachment is provided in electronic form only.

This file does not include any formulas as Table 433 through Table 444 were developed for presentation purposes and include inputs from other sources.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.3.2.1; Page No.: 17

QUESTION:

Please explain more fully why CCGT/C26 and K22/C29 were excluded from further evaluation when they both have higher NPV values than SCGT/C26.

RESPONSE:

For the purposes of the overall NFAT analysis of the Preferred Development Plan and alternative development plans, in order to be able to analyze a reasonable and meaningful range of alternatives from both an economic and financial perspective, not all plans were carried through to the economic and financial probabilistic analysis. The category of development plans with no new interconnection included seven plans where three were selected for further economic and financial probabilistic analysis – All Gas, K22/Gas and SCGT/C26.

As explained in Chapter 9, the net benefit of the K22/Gas development plan as compared to the K22/C29 development plan is small enough to result in indifference between the plans however the significantly greater investment required for the Conawapa G.S in the K22/C29 development plan resulted in it being excluded from further evaluation.

Although the CCGT/C26 development plan has a slightly higher incremental net present value than the SCGT/C26 development, for consistency in ongoing corporate analysis including comparisons to financial forecasts of past IFF development plans, the SCGT/C26 development plan was selected over the CCGT/C26 development plan.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.3.2.3; Page No.: 20

PREAMBLE: Appendix 9.3, Table 001 sets out the NPV calculation for the Preferred Plan under Reference Case.

QUESTION:

Please provide a schedule that for Table 001 (Preferred Plan) separates out the 40% of capital and OM&A costs for the US portion of the 750 MW interconnection from the Manitoba portion of the new interconnection and shows the overall NPV separately for each.

RESPONSE:

The cost referred to includes 100% of the Manitoba portion and 40% of the US portion. For the US portion, in order to model the financials, 18% of the capital was assumed to be funded directly during construction and 22% was assumed to be funded during operation (both were included in the analysis). The aggregate of the construction and operation period costs is 40% of the total project capital and maintenance cost. This is consistent with arrangements that were being discussed when the models were developed.

See the table below for a schedule of the US portion of the new 750 MW interconnection separated from the Manitoba portion based on Appendix 9.3, Table 001.

K19/C25/750MW (WPS Sale &Inv)
750 MW US Interconnection

Energy Price	**Reference**
Discount Rate	**Reference**
Capital Cost	**Reference**

	Capital & Related Costs (Millions of 2014$)					
	Transmission			Transmission O&M		
FYB	US T/L From Table 001	Manitoba Portion of Transmission Line	US Portion of Transmission Line	Fixed O&M From Table 001	Manitoba Portion of Fixed O&M	US Portion of Fixed O&M
2012	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00	0.00
2014	3.78	2.77	1.00	0.00	0.00	0.00
2015	6.75	5.55	1.21	0.00	0.00	0.00
2016	17.15	16.64	0.52	0.00	0.00	0.00
2017	24.95	24.95	0.00	0.00	0.00	0.00
2018	103.34	74.86	28.48	0.00	0.00	0.00
2019	85.16	74.86	10.30	0.00	0.00	0.00
2020	157.85	77.63	80.22	31.64	0.06	31.57
2021	0.00	0.00	0.00	30.06	0.06	29.99
2022	0.00	0.00	0.00	28.50	0.06	28.44
2023	0.00	0.00	0.00	26.83	0.06	26.76
2024	0.00	0.00	0.00	25.31	0.09	25.22
2025	0.00	0.00	0.00	23.90	0.12	23.78
2026	0.00	0.00	0.00	22.57	0.15	22.42
2027	0.00	0.00	0.00	21.29	0.18	21.11
2028	0.00	0.00	0.00	20.01	0.18	19.83
2029	0.00	0.00	0.00	18.78	0.18	18.60
2030	0.00	0.00	0.00	17.59	0.18	17.41
2031	0.00	0.00	0.00	16.43	0.18	16.25
2032	0.00	0.00	0.00	15.31	0.18	15.14
2033	0.00	0.00	0.00	14.23	0.18	14.05
2034	0.00	0.00	0.00	13.19	0.18	13.01
2035	0.00	0.00	0.00	12.39	0.18	12.22
2036	0.00	0.00	0.00	11.85	0.18	11.67
2037	0.00	0.00	0.00	11.32	0.18	11.14
2038	0.00	0.00	0.00	10.81	0.18	10.63
2039	0.00	0.00	0.00	10.32	0.18	10.14
2040	0.00	0.00	0.00	9.84	0.18	9.66
2041	0.00	0.00	0.00	9.38	0.18	9.20
2042	0.00	0.00	0.00	8.93	0.18	8.75
2043	0.00	0.00	0.00	8.49	0.18	8.31
2044	0.00	0.00	0.00	8.07	0.18	7.89
2045	0.00	0.00	0.00	7.66	0.18	7.48
2046	0.00	0.00	0.00	7.26	0.18	7.08
2047	0.00	0.00	0.00	6.88	0.18	6.70
2048	0.00	0.00	0.00	6.51	0.18	6.33
2049	0.68	0.68	0.00	6.15	0.18	5.97
2050	1.37	1.37	0.00	5.80	0.18	5.62
2051	4.11	4.11	0.00	5.46	0.18	5.29
2052	6.16	6.16	0.00	5.14	0.18	4.96

(Table continued on next page)

	Capital & Related Costs (Millions of 2014$)					
	Transmission			Transmission O&M		
FYB	US T/L From Table 001	Manitoba Portion of Transmission Line	US Portion of Transmission Line	Fixed O&M From Table 001	Manitoba Portion of Fixed O&M	US Portion of Fixed O&M
(Table continued from previous page)						
2053	18.49	18.49	0.00	4.82	0.18	4.64
2054	18.49	18.49	0.00	4.52	0.18	4.34
2055	19.18	19.18	0.00	4.22	0.18	4.05
2056	0.00	0.00	0.00	3.94	0.18	3.76
2057	0.00	0.00	0.00	3.66	0.18	3.48
2058	0.00	0.00	0.00	3.40	0.18	3.22
2059	0.00	0.00	0.00	3.14	0.18	2.96
2060	0.00	0.00	0.00	0.18	0.18	0.00
2061	0.00	0.00	0.00	0.18	0.18	0.00
2062	0.00	0.00	0.00	0.18	0.18	0.00
2063	0.00	0.00	0.00	0.18	0.18	0.00
2064	2.09	2.09	0.00	0.18	0.18	0.00
2065	4.18	4.18	0.00	0.18	0.18	0.00
2066	12.53	12.53	0.00	0.18	0.18	0.00
2067	18.79	18.79	0.00	0.18	0.18	0.00
2068	56.37	56.37	0.00	0.18	0.18	0.00
2069	56.37	56.37	0.00	0.18	0.18	0.00
2070	58.46	58.46	0.00	0.18	0.18	0.00
2071	0.00	0.00	0.00	0.18	0.18	0.00
2072	0.00	0.00	0.00	0.18	0.18	0.00
2073	0.00	0.00	0.00	0.18	0.18	0.00
2074	0.00	0.00	0.00	0.18	0.18	0.00
2075	0.00	0.00	0.00	0.18	0.18	0.00
2076	0.00	0.00	0.00	0.18	0.18	0.00
2077	0.00	0.00	0.00	0.18	0.18	0.00
2078	0.00	0.00	0.00	0.18	0.18	0.00
2079	0.00	0.00	0.00	0.18	0.18	0.00
2080	0.00	0.00	0.00	0.18	0.18	0.00
2081	0.00	0.00	0.00	0.18	0.18	0.00
2082	0.00	0.00	0.00	0.18	0.18	0.00
2083	0.00	0.00	0.00	0.18	0.18	0.00
2084	0.68	0.68	0.00	0.18	0.18	0.00
2085	1.37	1.37	0.00	0.18	0.18	0.00
2086	4.11	4.11	0.00	0.18	0.18	0.00
2087	6.16	6.16	0.00	0.18	0.18	0.00
2088	18.49	18.49	0.00	0.18	0.18	0.00
2089	18.49	18.49	0.00	0.18	0.18	0.00
2090	19.18	19.18	0.00	0.18	0.18	0.00
Salvage Value	4.78	4.78	0.00	0.00	0.00	0.00
PV @ 5.05%	$ 337.17	$ 243.42	$ 93.75	$ 228.35	$ 2.26	$ 226.09

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.3.2.3; Page No.: 20

PREAMBLE: Appendix 9.3, Table 002 sets out the NPV calculation for the Preferred Plan under Reference Case.

QUESTION:

Please provide a schedule that for Table 002 (Plan 15) separates out the 2/3's of capital and OM&A costs for the US portion of the 750 MW interconnection from the Manitoba portion of the new interconnection and shows the overall NPV separately for each.

RESPONSE:

The cost referred to includes 100% of the Manitoba portion and 2/3 of the US portion. For the US portion, in order to model the financials, 44.5% of the capital was assumed to be funded directly during construction and 22% was assumed to be funded during operation (both were included in the analysis). The aggregate of the construction and operation period costs is 2/3 of the total project capital and maintenance cost. This is consistent with arrangements that were being discussed when the models were developed.

See the table below for a schedule of the US portion of the new 750 MW interconnection separated from the Manitoba portion based on Appendix 9.3, Table 002.

K19/C25/750MW
750 MW US Interconnection

Energy Price	**Reference**
Discount Rate	**Reference**
Capital Cost	**Reference**

	Capital & Related Costs (Millions of 2014$)					
	Transmission			Transmission O&M		
FYB	US T/L From Table 002	Manitoba Portion of Transmission Line	US Portion of Transmission Line	Fixed O&M From Table 002	Manitoba Portion of Fixed O&M	US Portion of Fixed O&M
2012	0.00	0.00	0.00	0.00	0.00	0.00
2013	0.00	0.00	0.00	0.00	0.00	0.00
2014	5.28	2.77	2.51	0.00	0.00	0.00
2015	8.56	5.55	3.01	0.00	0.00	0.00
2016	17.93	16.64	1.30	0.00	0.00	0.00
2017	24.95	24.95	0.00	0.00	0.00	0.00
2018	146.07	74.86	71.21	0.00	0.00	0.00
2019	100.61	74.86	25.75	0.00	0.00	0.00
2020	278.17	77.63	200.54	34.76	0.06	34.69
2021	0.00	0.00	0.00	33.28	0.06	33.22
2022	0.00	0.00	0.00	31.75	0.06	31.69
2023	0.00	0.00	0.00	29.94	0.06	29.88
2024	0.00	0.00	0.00	28.29	0.09	28.20
2025	0.00	0.00	0.00	26.76	0.12	26.64
2026	0.00	0.00	0.00	25.31	0.15	25.16
2027	0.00	0.00	0.00	23.91	0.18	23.73
2028	0.00	0.00	0.00	22.53	0.18	22.35
2029	0.00	0.00	0.00	21.19	0.18	21.01
2030	0.00	0.00	0.00	19.89	0.18	19.71
2031	0.00	0.00	0.00	18.63	0.18	18.46
2032	0.00	0.00	0.00	17.42	0.18	17.24
2033	0.00	0.00	0.00	16.24	0.18	16.06
2034	0.00	0.00	0.00	15.10	0.18	14.92
2035	0.00	0.00	0.00	14.22	0.18	14.05
2036	0.00	0.00	0.00	13.60	0.18	13.42
2037	0.00	0.00	0.00	13.00	0.18	12.82
2038	0.00	0.00	0.00	12.42	0.18	12.24
2039	0.00	0.00	0.00	11.86	0.18	11.68
2040	0.00	0.00	0.00	11.32	0.18	11.14
2041	0.00	0.00	0.00	10.79	0.18	10.61
2042	0.00	0.00	0.00	10.28	0.18	10.10
2043	0.00	0.00	0.00	9.79	0.18	9.61
2044	0.00	0.00	0.00	9.31	0.18	9.13
2045	0.00	0.00	0.00	8.84	0.18	8.66
2046	0.00	0.00	0.00	8.39	0.18	8.22
2047	0.00	0.00	0.00	7.96	0.18	7.78
2048	0.00	0.00	0.00	7.54	0.18	7.36
2049	0.68	0.68	0.00	7.13	0.18	6.95
2050	1.37	1.37	0.00	6.74	0.18	6.56
2051	4.11	4.11	0.00	6.36	0.18	6.18
2052	6.16	6.16	0.00	5.99	0.18	5.81

(Table continued on next page)

	Capital & Related Costs (Millions of 2014$)					
	Transmission			Transmission O&M		
FYB	US T/L From Table 002	Manitoba Portion of Transmission Line	US Portion of Transmission Line	Fixed O&M From Table 002	Manitoba Portion of Fixed O&M	US Portion of Fixed O&M
(Table continued from previous page)						
2053	18.49	18.49	0.00	5.63	0.18	5.45
2054	18.49	18.49	0.00	5.29	0.18	5.11
2055	19.18	19.18	0.00	4.95	0.18	4.77
2056	0.00	0.00	0.00	4.63	0.18	4.45
2057	0.00	0.00	0.00	4.32	0.18	4.14
2058	0.00	0.00	0.00	4.02	0.18	3.84
2059	0.00	0.00	0.00	3.73	0.18	3.55
2060	0.00	0.00	0.00	0.18	0.18	0.00
2061	0.00	0.00	0.00	0.18	0.18	0.00
2062	0.00	0.00	0.00	0.18	0.18	0.00
2063	0.00	0.00	0.00	0.18	0.18	0.00
2064	2.09	2.09	0.00	0.18	0.18	0.00
2065	4.18	4.18	0.00	0.18	0.18	0.00
2066	12.53	12.53	0.00	0.18	0.18	0.00
2067	18.79	18.79	0.00	0.18	0.18	0.00
2068	56.37	56.37	0.00	0.18	0.18	0.00
2069	56.37	56.37	0.00	0.18	0.18	0.00
2070	58.46	58.46	0.00	0.18	0.18	0.00
2071	0.00	0.00	0.00	0.18	0.18	0.00
2072	0.00	0.00	0.00	0.18	0.18	0.00
2073	0.00	0.00	0.00	0.18	0.18	0.00
2074	0.00	0.00	0.00	0.18	0.18	0.00
2075	0.00	0.00	0.00	0.18	0.18	0.00
2076	0.00	0.00	0.00	0.18	0.18	0.00
2077	0.00	0.00	0.00	0.18	0.18	0.00
2078	0.00	0.00	0.00	0.18	0.18	0.00
2079	0.00	0.00	0.00	0.18	0.18	0.00
2080	0.00	0.00	0.00	0.18	0.18	0.00
2081	0.00	0.00	0.00	0.18	0.18	0.00
2082	0.00	0.00	0.00	0.18	0.18	0.00
2083	0.00	0.00	0.00	0.18	0.18	0.00
2084	0.68	0.68	0.00	0.18	0.18	0.00
2085	1.37	1.37	0.00	0.18	0.18	0.00
2086	4.11	4.11	0.00	0.18	0.18	0.00
2087	6.16	6.16	0.00	0.18	0.18	0.00
2088	18.49	18.49	0.00	0.18	0.18	0.00
2089	18.49	18.49	0.00	0.18	0.18	0.00
2090	19.18	19.18	0.00	0.18	0.18	0.00
Salvage Value	4.78	4.78	0.00	0.00	0.00	0.00
PV @ 5.05%	$ 477.79	$ 243.42	$ 234.37	$ 256.89	$ 2.26	$ 254.63

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.3.3; Page No.: 24

PREAMBLE: Chapter 9, page 24 states that "this tax (the capital tax) is applied at a rate of 0.5% to capital invested by Manitoba Hydro in the province".

QUESTION:

Does this mean that Manitoba Hydro would not pay capital tax to the province on any investment it makes in the US portion of the 750 MW interconnection?

RESPONSE:

As the capital tax treatment for the US portion of the interconnection is uncertain at this time, the financial analysis included the capital tax on the total paid up capital of the corporation, including the US portion of the 750 MW interconnection. The capital tax was also included on capital costs assumed to be funded directly during construction for the US portion of the 750MW interconnection in the economic analysis.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.3.3; Page No.: 24

PREAMBLE: Chapter 9, page 24 states that "this tax (the capital tax) is applied at a rate of 0.5% to capital invested by Manitoba Hydro in the province".

QUESTION:

What would be the NPV value of the payments if Manitoba Hydro did have to pay capital tax to the province on its investment in US transmission under the 40% and 66.67% investments assumptions?

RESPONSE:

Please refer to Manitoba Hydro's response to CAC/MH I-119a.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.3.2.3; Page No.: 21

PREAMBLE: During the September 5-6 Technical Conference Manitoba Hydro indicated that WPS was still interested in pursuing the 300 MW contract but was not interested in investing in the 750 MW interconnection.

QUESTION:

Please provide the NPV for a "Plan 16" - similar to Plan 15 except Manitoba Hydro is responsible for 2/3's of the capital and O&M costs for the U.S. portion of the 750 MW interconnection. Please also provide the associated economic summary table (per Appendix 9.3).

RESPONSE:

The proposed “Plan 16” would be identical to Plan 15. Plan 15 assumes that Manitoba Hydro is responsible for 2/3's of the capital and O&M costs for the US portion of the 750 MW interconnection.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.3.2.3; Page No.: 21

QUESTION:

Please recalculate the NPV for this "Plan 16" using real discount rates of 8% and 10%.

RESPONSE:

In Order 119/13, the PUB directed that Manitoba Hydro will not have to respond to this Information Request.

REFERENCE: Chapter 9: Economic Evaluations - Reference Scenario; Section: 9.2.3; Page No.: 8

QUESTION:

Please calculate the NPVs for Plans 2, 4, 5, 6, 7, 10, 11,12,13,14 and 15 using 8% and 10% real discount rates. Please provide the associated Economic Summary tables similar to those in Appendix 9.3, Table 001.

RESPONSE:

In Order 119/13, the PUB directed that Manitoba Hydro will not have to respond to this Information Request.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.1.1.1; Page No.: 3

PREAMBLE: The reference case assumes that water rental rates stay constant over the study period.

QUESTION:

Please provide a history of water rental rates over the past 20 years (i.e., when have they changed and by how much?)

RESPONSE:

The water rental rates are provided in the table below. Water rentals are assessed for each hydro-electric generating station on a calendar year basis and are calculated based on the greater of:

30) a fixed rate (in $ per installed horsepower) multiplied by the installed capacity;

31) a fixed rate (in $ per horsepower year) multiplied by the electric output for the year.

In almost all circumstances, the second calculation is higher and therefore determines the water rental assessment. The current rate of $20.32/hp-year is equivalent to 3.3426 mills per KWh.

WATER RENTAL RATES.

Fiscal Year	Per Installed Horsepower		Per Horsepower Year Generated	
	Rate	Change in Rate	Rate	Change in Rate
1993-1994	3.96		9.90	
1994-1995	3.96	-	9.90	-
1995-1996	3.96	-	9.90	-
1996-1997	3.96	-	9.90	-
1997-1998	3.96	-	9.90	-
1998-1999	3.96	-	9.90	-
1999-2000	3.96	-	9.90	-
2000-2001	3.96	-	9.90	-
2001-2002*	8.13	4.17	20.32	10.42
2002-2003	8.13	-	20.32	-
2003-2004	8.13	-	20.32	-
2004-2005	8.13	-	20.32	-
2005-2006	8.13	-	20.32	-
2006-2007	8.13	-	20.32	-
2007-2008	8.13	-	20.32	-
2008-2009	8.13	-	20.32	-
2009-2010	8.13	-	20.32	-
2010-2011	8.13	-	20.32	-
2011-2012	8.13	-	20.32	-
2012-2013	8.13	-	20.32	-

Note * Effective April 1, 2001.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.1.1.1; Page No.: 4

QUESTION:

For purposes of Figure 10.1 what assumption were made regarding the low and high values for water rentals?

RESPONSE:

For the purpose of Figure 10.1, a sensitivity to the water rental rate was performed for the All Gas development plan and the Preferred Development Plan whereby the rate was adjusted by +/- $1/MW.h relative to the 3.34 $/MW.h reference scenario rate.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.1; Page No.: 43

PREAMBLE: Appendix 9.3, page 43 states the "the mean and variance of the levelized electricity price are 22.3 and 45.6 respectively".

QUESTION:

Please describe further what the 22.3 is the mean for (i.e., what electricity price, levelized over what period, etc.).

RESPONSE:

The 22.3 is the mean of the 9-point representation in Figure 2.3 of Appendix 9.3 of the levelized on-peak electricity price forecasts over a 20 year forecast period. The calculation of the mean is a step in the methodology to develop probabilities associated with the Energy Prices factor used in the probabilistic analysis.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.2; Page No.: 56

QUESTION:

Do the interest rates set out in Figure 2.12 include the 1% debt guarantee fee?

RESPONSE:

The interest rates in Figure 2.12 on page 56 of Appendix 9.3 do not include the 1% debt guarantee fee.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.2; Page No.: 56

QUESTION:

If yes, please reconcile the material difference between the expected value of 5.09% and the most likely value of 6.3%.

RESPONSE:

Please see Manitoba Hydro's response to CAC/MH I-125a.

REFERENCE: Volume: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.2; Page No.: 55

PREAMBLE: Appendix 9.3, page 7 indicates the Reference value Manitoba Hydro's nominal cost of debt is 6.3%.

QUESTION:

Please reconcile the difference between the 4.65% Reference value for nominal interest rates set out in Figure 2.12 with the 5.3% Reference value (i.e. 6.3% less 1% debt guarantee) set out in Appendix 9.3, page 7

RESPONSE:

Please see the response to CAC/MH I-104.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.2; Page No.: 56

QUESTION:

Please provide a schedule setting out the determination of the Low and High real discount rates of 3.35% and 6.5% respectively. In doing so, please indicate how the calculation account for the apparent correlation between real interest rates and inflation (per Table 2.10).

RESPONSE:

The schedule below demonstrates the derivation of the low and high discount rate or weighted average cost of capital (WACC), both in nominal and real terms, utilized in the NFAT analysis. The same methodology was used for each range, as well as the reference case, such that low nominal rates were adjusted using low inflation, and high nominal rates were adjusted using high inflationary values. The values for inflation were 1% for the low case and 3% for the high case to reflect the Bank of Canada's inflation target bounds.

Capital Source	Target Capital Structure	Nominal Rates				Real Rates			
		Low	High	Low	High	Low	High	Low	High
		Rate		*Weighted Rate*		*Rate*		*Weighted Rate*	
CDN 10 Year+Bond Yield		2.30%	7.00%						
10 Year+ Credit Spread		0.35%	0.95%						
Provincial Guarantee Fee		1.00%	1.00%						
Long-Term Debt	75%	3.65%	8.95%	2.74%	6.71%	2.62%	5.78%	1.97%	4.33%
Long Term Debt		3.65%	8.95%						
Imputed Cost of Equity		3.00%	3.00%						
Equity	25%	6.65%	11.95%	1.66%	2.99%	5.59%	8.69%	1.40%	2.17%
Total	100%			4.40%	9.70%			3.35%	6.50%

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 2.3.3; Page No.: 59

PREAMBLE: At the September 5-6, 2013 Technical Conference Manitoba Hydro indicated that it assumed the three impact factors were not correlated.

QUESTION:

Please discuss the likely correlation if any between the high/reference/low real capital cost escalation factors used (page 59) and the high/medium/low CPI forecasts underlying the determination of the discount rate probability distribution. Won't the same factors that influence capital cost escalation also affect CPI?

RESPONSE:

Capital cost escalation refers to “real” rather than “nominal” increases in construction costs. By real, Manitoba Hydro defines this as over and above general inflation reflected in the CPI. This real capital cost escalation is separate from the general inflation reflected in CPI, and is typically driven by different factors such as global demand for particular commodities or project components.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.1.4; Page No.: 17

QUESTION:

Please re-do Tables 10.5, 10.6 and 10.7 to include a development plan similar to Plan 15 but where Manitoba Hydro is responsible for 2/3's of the capital and O&M cost of the US portion of the 750 MW interconnection.

RESPONSE:

Plan 15 assumes that Manitoba Hydro is responsible for 2/3's of the capital and O&M costs for the US portion of the 750MW interconnection. Plan 15 is included in Tables 10.5, 10.6, and 10.7.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.1.4.2; Page No.: 27

QUESTION:

Please re-do Figure 10.14 to also include this development plan.

RESPONSE:

Please refer to Manitoba Hydro's response to CAC/MH I-120a. Plan 15 is already included with Plans 5 and 14 in Figure 10.17.

REFERENCE: Volume: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.1.4.2; Page No.: 30

QUESTION:

Please re-do Figures 10.17 and 10.20, removing Plan 14 and replacing it with this development plan.

RESPONSE:

Please refer to Manitoba Hydro's response to CAC/MH I-129a. This development plan is Plan 15 which is already included in Figures 10.17 and 10.20.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.2.1; Page No.: 41

QUESTION:

Does the sensitivity analysis assume that all long-term export contract commitments continue to be met during the drought period? If not, which contracts are met in each case?

RESPONSE:

Yes. The drought sensitivity analysis in Chapter 10 Section 10.2.1 assumes that Manitoba Hydro fulfills all its obligations to deliver firm power in accordance with the terms and conditions of the export contracts.

The drought sensitivity analysis in Chapter 10 does not contemplate a drought worse than the drought of record. In such an event Manitoba Hydro has the right to reduce export deliveries without penalty to the extent necessary to meet its obligation to serve Manitoba load first.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.2.3; Page No.: 52

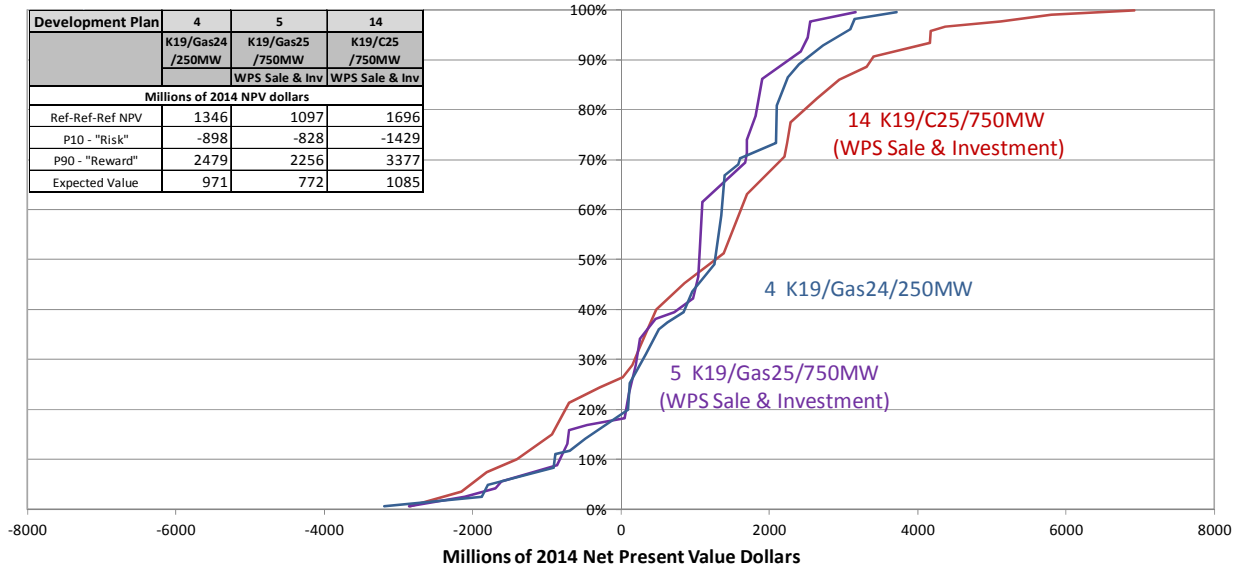
QUESTION:

Please provide a revised version of Figures 10.13 and 10.14 that also includes Plan #4.

RESPONSE:

An updated version of Figure 10.14 is included below. Please note that Figure 10.13 already includes Plan 4. For additional information, Figure 10.19 provides a comparison of Plans 4 and Plan 5.

Development Plan	4	5	14
	K19/Gas24 /250MW	K19/Gas25 /750MW	K19/C25 /750MW
		WPS Sale & Inv	WPS Sale & Inv
Millions of 2014 NPV dollars			
Ref-Ref-Ref NPV	1346	1097	1696
P10 - "Risk"	-898	-828	-1429
P90 - "Reward"	2479	2256	3377
Expected Value	971	772	1085



REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: 10.2.4; Page No.: 53

QUESTION:

The second last sentence (lines 18-19) suggests that the costs savings from the deferral are greater than the value of the lost revenues. However, the last sentence (lines 19-21) suggests the opposite. Please reconcile.

RESPONSE:

The second last sentence (lines 18-19) does not suggest that the costs savings from the deferral are greater than the value of the lost revenues. It states that "These lower revenues <u>will be partially offset</u> by the capital cost savings from the deferral" meaning that the capital cost savings are less than the value of reduced export revenues created by the in service dates deferral of Keeyask and Conawapa generating stations.

As clarification, the last sentence (lines 19-21) may be better understood as follows, "The decrease in NPV is attributable to the decrease in export revenues being more than the savings of delaying the capital expenditures by one year."

REFERENCE: Appendix 11.5 Enlarged Figures 11.1 – 11.7

QUESTION:

Please provide similarly enlarged full page figures for the S-Curves in Chapter 10 (Figures 10.11-10.21) and for any S-Curves provided in response to interrogatories.

RESPONSE:

Please see Figures 2.7.7 through to 2.7.24 of Appendix 9.3 (beginning at p. 73) for larger size figures of the s-curves provided in Chapter 10.

REFERENCE: Appendix 11.1 Net Capital Expenditures; Page No.: 9

PREAMBLE: Appendix 2.4 (page 27) shows 2019 In-Service Keeyask Generation costs of $5.8 B.

QUESTION:

Please reconcile the Appendix 2.4 capital costs for Keeyask generation with the $5.5 B cost provided in Appendix 11.1.

RESPONSE:

In-service costs for Keeyask Generating Station (2019 ISD) in Appendix 2.4 are $6.0B.

Net Capital expenditures for Keeyask Generating Station (2019 ISD) in Appendix 11.1 are $5.5B based on the reference case. These numbers are different because this value does not include the labour reserve and the escalation reserve amount applied to the labour reserve.

1

	Keeyask 2019/20 (Billions of Dollars)	
	Project Control Budget	***NFAT Scenarios (Capital Costs and Economic Indicators)***
	CEF12/IFF12	Reference
Generating Station		
Point Estimate	3.05	3.05
Contingency	0.53	0.53
Management Reserve		
Labour Reserve	0.38	0.00
Escalation Reserve	0.12	0.10
Total Base Dollars	**4.1**	**3.7**
Total Dollars Spent As of March 31, 2012	0.50	0.50
2012 Base Estimate	4.08	3.68
Escalation @ CPI	0.40	0.37
Capitalized Interest	0.85	0.79
In-Service Cost:	**5.8**	**5.3**
Interest on MH Equity	**0.20**	**0.17**
Total In-Service Cost:	**6.0**	**5.5**

REFERENCE: Appendix 11.1 Net Capital Expenditures; Page No.: 13

PREAMBLE: Appendix 2.4 (page 13) shows 2025 In-Service Conawapa Generation costs of $10.2 B.

QUESTION:

Please reconcile the Appendix 2.4 capital costs for Conawapa generation with the $9.3 M cost provided in Appendix 11.1.

RESPONSE:

In-service costs for Conawapa Generating Station (2025 ISD) in Appendix 2.4 are $10.2B.

Net Capital expenditures for Conawapa Generating Station (2025 ISD) in Appendix 11.1 are $9.3B based on the reference case. These numbers are different because this value does not include the labour reserve and the escalation reserve amount applied to the labour reserve.

1

	Conawapa 2025/26 (Billions of Dollars)	
	Project Control Budget	***NFAT Scenarios (Capital Costs and Economic Indicators)***
	CEF12/IFF12	Reference
Generating Station		
Point Estimate	4.53	4.53
Contingency	0.75	0.75
Management Reserve		
Labour Reserve	0.51	0.00
Escalation Reserve	0.34	0.31
Total Base Dollars	**6.1**	**5.6**
Total Dollars Spent As of March 31, 2012	0.23	0.23
2012 Base Estimate	6.13	5.58
Escalation @ CPI	1.24	1.14
Capitalized Interest	2.59	2.40
In-Service Cost:	**10.2**	**9.3**
Total In-Service Cost:	**10.2**	**9.3**

REFERENCE: Appendix 11.1 Net Capital Expenditures; Page No.: 5

QUESTION:

Does the $134 M shown under Trans-US T/L represent the cost of the Manitoba portion of the 250 MW line? If not, please explain what the cost represents.

RESPONSE:

The $134 million amount shown under Trans-US T/L represents the projected costs for the Manitoba portion of the 250 MW tie line. The 250 MW tie line option does not require any investment in the U.S.

REFERENCE: Appendix 11.1 Net Capital Expenditures; Page No.: 6

QUESTION:

Does the cost shown on page 6 under Trans-US T/L represent 40% of the cost of the US portion of the 750 MW line plus the cost of the Manitoba portion. If not, what does it represent.

RESPONSE:

The $628 million cost shown on page 6 under Trans-US T/L reflects 100% of the Manitoba portion (including the replacement of the Canadian station as described in the response to CAC/MH I-138) and 18% of the total capital cost of the US portion.

REFERENCE: Appendix 11.1 Net Capital Expenditures; Page No.: 6

QUESTION:

Please explain why the 2050-2056 costs for Trans-US T/L are the same on pages 6 and 7 when Manitoba Hydro's investment in the U.S. portion is 40% in one case and 66.67% in the other.

RESPONSE:

The costs included in the column labeled “Trans – US T/L” for the period 2050 to 2056 reflect the replacement of substation assets on the Manitoba portion of the interconnection that have reached the end of their service life. These costs are entirely the responsibility of Manitoba Hydro regardless of Manitoba Hydro’s investment in the U.S. portion of the interconnection. Please see the response to CAC/MH I-151a for a breakdown of capital costs for the Manitoba and U.S. portions of the 250 MW and 750 MW interconnections.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.2; Page No.: 7

QUESTION:

Please provide a schedule that sets out Manitoba Hydro's approved Residential rates for the last 13 years and the effective date for each change.

RESPONSE:

The Residential rates in effect between 2001 and 2013 are as follows:

2001 – 2007: There were four rate increases during this time. All incorporated a first block energy amount of 175 kWh and all were based on a declining block structure meaning that the first block charge was higher than the tail block charge.

Effective Date:	Nov 1, 2001	Aug 1, 2004	Apr 1, 2005	Mar 1, 2007
Monthly Basic Charge:				
<200 Amp	$6.25	$6.25	$6.25	$6.24
>200 Amp	$12.50	$12.50	$12.50	$12.48
Energy Charge:				
First 175 kWh @	$0.05780	$0.05780	$0.05780	$0.05940
Balance of kWh @	$0.05160	$0.05496	$0.05654	$0.05790

2008 – 2010: There were three rate changes during this time. All incorporated a first block energy amount of 900 kWh and all were based on an inverted rate structure meaning that the first block charge was lower than the tail block charge.

Effective Date:	July 1, 2008	Apr 1, 2009	Apr 1, 2010
Monthly Basic Charge:			
<200 Amp	$6.60	$6.85	$6.85
>200 Amp	$13.20	$13.70	$13.70
Energy Charge:			
First 900 kWh @	$0.06080	$0.06250	$0.06380
Balance of kWh @	$0.06123	$0.06300	$0.06570

2011 – 2013: There were four rate changes during this time, all based on a single energy charge.

Effective Date:	**Apr 1, 2011**	**Apr 1, 2012**	**Sep 1, 2012**	**May 1, 2013**
Monthly Basic Charge:				
<200 Amp	$6.85	$6.85	$6.85	$7.09
>200 Amp	$13.70	$13.70	$13.70	$14.18
Energy Charge:				
All kWh @	$0.06620	$0.06770	$0.06940	$0.07183

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.2; Page No.: 8

QUESTION:

Based on the average annual rate increases associated with each of the eight plans and Manitoba Hydro's current rate design practices, please provide projections of the Residential rates (i.e. service charge and volumetric charge) for years set out in Figure 11.1 under each Plan.

RESPONSE:

Manitoba Hydro's current Residential rate design as of May 1, 2013 consists of a monthly Basic Charge ($7.09) and a single Energy Charge ($0.07183). Assuming this rate design was to remain constant over the next 50 years, and that both components of the rate (Basic Charge and Energy Charge) increased or decreased equally based on the overall projected percentage change in General Consumer rates, then the following Residential rates would be indicative for each of the eight development plans. Please note that actual rate increases will vary from those projected in this analysis, and will be dependent upon future revenue requirements. For simplicity purposes, only rates for each 10 year period are shown in the following tables.

1

	Projected Residential Monthly Basic Charge					
	2013	**2023**	**2033**	**2043**	**2053**	**2063**
All Gas	$7.09	$9.95	$11.11	$14.31	$16.99	$19.74
K22 Gas	$7.09	$9.99	$11.31	$13.87	$15.65	$17.27
Gas C26	$7.09	$10.32	$11.67	$13.16	$15.19	$16.17
K19 Gas 250mw	$7.09	$9.95	$10.97	$13.56	$15.46	$17.61
K19 C25 250mw	$7.09	$10.42	$11.66	$12.66	$14.06	$14.49
K19 Exp C25 750mw	$7.09	$10.41	$11.35	$12.51	$13.88	$14.14
K19 Imp C31 750mw	$7.09	$10.27	$11.20	$13.12	$14.24	$14.41
K19 Imp Gas 750mw	$7.09	$10.04	$11.10	$13.49	$15.52	$17.39

	Projected Residential Energy Charge ($/kWh)					
	2013	**2023**	**2033**	**2043**	**2053**	**2063**
All Gas	$0.07183	$0.1004	$0.1122	$0.1443	$0.1712	$0.1989
K22 Gas	$0.07183	$0.1013	$0.1148	$0.1408	$0.1591	$0.1757
Gas C26	$0.07183	$0.1045	$0.1182	$0.1332	$0.1538	$0.1636
K19 Gas 250mw	$0.07183	$0.1004	$0.1107	$0.1366	$0.1558	$0.1775
K19 C25 250mw	$0.07183	$0.1056	$0.1182	$0.1282	$0.1424	$0.1468
K19 Exp C25 750mw	$0.07183	$0.1052	$0.1147	$0.1263	$0.1401	$0.1428
K19 Imp C31 750mw	$0.07183	$0.1039	$0.1132	$0.1325	$0.1439	$0.1456
K19 Imp Gas 750mw	$0.07183	$0.1013	$0.1121	$0.1363	$0.1571	$0.1760

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.2; Page No.: 7

QUESTION:

Please provide a schedule that for each of the eight plan's (per page 3) Reference case financial projection shows for each year of the 50 year study period: a) the Additional General Consumers Revenue; b) the net present value of the additional revenue; and c) the cumulative value of the net present value from 2013 to the year concerned. Note: The discount rate used should be the nominal equivalent to the Reference case's real value of 5.05%.

RESPONSE:

Please refer to the response to PUB/MH I-149(a).

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.2; Page No.: 7

QUESTION:

Based on the results from part (a) please provide a graph that shows the year to year change in the cumulative net present value of Additional General Consumers Revenues for each of the eight development plans over the study period.

RESPONSE:

Please refer to Manitoba Hydro's response to PUB/MH I-149(a).

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.2; Page No.: 8

QUESTION:

Please provide the equivalent of Figure 11.1 but instead of showing cumulative percentage rate increase please show the cumulative net present value of Additional General Consumers Revenue.

RESPONSE:

Please refer to the response to PUB/MH I-149(a).

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.3; Page No.: 13

PREAMBLE: Appendix F contains Manitoba Hydro's projected growth for provincial GDP.

QUESTION:

Please provide a schedule that, for each of the eight plans, sets out Manitoba Hydro's net debt as a percentage of provincial GDP for each year in the study period.

RESPONSE:

The ratio of net tax-supported provincial debt as a percent of provincial GDP is a measure used by organizations such as credit rating agencies in their review of provincial debt levels. However, as Manitoba Hydro's long-term debt advances are considered to be self-supporting, the Corporation's net debt levels are excluded from this ratio. Therefore, the ratio of Manitoba Hydro's net debt as a percentage of provincial GDP for each year in the study period is not an appropriate measure when reviewing Manitoba Hydro's debt levels, and organizations such as credit rating agencies do not use this measure in their analysis of Manitoba Hydro.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.3; Page No.: 13

QUESTION:

Please provide a schedule that sets out Manitoba Hydro's historical borrowing for each of the last 20 years.

RESPONSE:

The following table shows the historical borrowings (net of long term debt retirements and sinking fund transactions) as reported in the Consolidated Statement of Cash Flows within the Manitoba Hydro-Electric Board Annual Reports:

Fiscal Year	(millions)
2013	528
2012	627
2011	562
2010	614
2009	301
2008	391
2007	127
2006	(26)
2005	136
2004	647
2003	79
2002	(27)
2001	51
2000	262
1999	(66)
1998	(54)
1997	178
1996	68
1995	(283)
1994	388

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.3; Page No.: 13

QUESTION:

Please provide a schedule that sets out the required annual borrowing over the study for each of the eight plan's Reference cases.

RESPONSE:

Please see the attached table that shows the projected borrowings (net of long term debt retirements and sinking fund transactions) for the values corresponding with P10/P25/P50/P75/P90.

Projected Borrowings
(net of long term debt retirements and sinking fund transactions)

Fiscal Year Ending	Development Plan	P10	P25	P50	P75	P90
2014	All Gas	1,340	1,540	1,540	1,540	1,540
	K22 Gas	1,340	1,540	1,540	1,540	1,540
	Gas C26	1,340	1,540	1,540	1,540	1,540
	K19 Gas 250mw	1,340	1,540	1,540	1,540	1,540
	K19 C25 250mw	1,340	1,540	1,540	1,540	1,540
	K19 Exp C25 750mw	1,340	1,540	1,540	1,540	1,540
	K19 Imp C31 750mw	1,340	1,540	1,540	1,540	1,540
	K19 Imp Gas 750mw	1,340	1,540	1,540	1,540	1,540
2017	All Gas	653	659	665	844	858
	K22 Gas	650	659	844	850	858
	Gas C26	664	844	856	858	861
	K19 Gas 250mw	1,438	1,447	1,458	1,646	1,652
	K19 C25 250mw	1,491	1,637	1,652	1,837	1,850
	K19 Exp C25 750mw	1,542	1,641	1,652	1,837	1,850
	K19 Imp C31 750mw	1,444	1,452	1,596	1,638	1,651
	K19 Imp Gas 750mw	1,439	1,450	1,457	1,646	1,652
2020	All Gas	(11)	11	12	179	179
	K22 Gas	813	813	980	981	1,014
	Gas C26	212	254	395	413	462
	K19 Gas 250mw	634	651	836	993	995
	K19 C25 250mw	849	1,033	1,036	1,233	1,400
	K19 Exp C25 750mw	1,035	1,048	1,232	1,246	1,402
	K19 Imp C31 750mw	832	835	851	1,000	1,087
	K19 Imp Gas 750mw	651	833	836	995	1,036
2023	All Gas	(53)	98	115	115	135
	K22 Gas	512	683	690	876	882
	Gas C26	1,301	1,329	1,529	1,697	1,732
	K19 Gas 250mw	65	68	104	248	256
	K19 C25 250mw	1,072	1,240	1,421	1,441	1,815
	K19 Exp C25 750mw	1,244	1,316	1,437	1,624	1,660
	K19 Imp C31 750mw	63	69	104	248	263
	K19 Imp Gas 750mw	(128)	47	68	243	260
2026	All Gas	(138)	(135)	(127)	63	67
	K22 Gas	(266)	(262)	(78)	(72)	86
	Gas C26	544	703	896	1,087	1,093
	K19 Gas 250mw	(387)	(383)	(368)	(188)	(91)
	K19 C25 250mw	298	472	482	858	1,034
	K19 Exp C25 750mw	386	478	661	855	1,044
	K19 Imp C31 750mw	38	209	220	224	329
	K19 Imp Gas 750mw	(379)	(378)	(358)	(186)	(141)
2029	All Gas	27	179	209	376	401
	K22 Gas	(53)	(48)	112	158	319
	Gas C26	(128)	(98)	(88)	59	72
	K19 Gas 250mw	(76)	(53)	135	151	310
	K19 C25 250mw	(369)	(353)	(223)	(182)	(150)
	K19 Exp C25 750mw	(379)	(344)	(227)	(181)	(158)
	K19 Imp C31 750mw	1,213	1,324	1,514	1,860	1,897
	K19 Imp Gas 750mw	(299)	(272)	(261)	(238)	(90)

Projected Borrowings
(net of long term debt retirements and sinking fund transactions)

Fiscal Year Ending	Development Plan	P10	P25	P50	P75	P90
2032	All Gas	(240)	(232)	(199)	(192)	(115)
	K22 Gas	(300)	(262)	(253)	(105)	(64)
	Gas C26	(358)	(346)	(304)	(292)	(266)
	K19 Gas 250mw	(286)	(128)	(79)	(61)	(30)
	K19 C25 250mw	(447)	(406)	(363)	(324)	(239)
	K19 Exp C25 750mw	(456)	(433)	(390)	(367)	(338)
	K19 Imp C31 750mw	(149)	(138)	(12)	34	76
	K19 Imp Gas 750mw	(300)	(262)	(85)	(50)	84
2035	All Gas	66	80	262	281	409
	K22 Gas	(568)	(501)	(368)	(291)	(239)
	Gas C26	(337)	(296)	(257)	(239)	(124)
	K19 Gas 250mw	(267)	(235)	(169)	(137)	(98)
	K19 C25 250mw	(820)	(537)	(390)	(333)	(315)
	K19 Exp C25 750mw	(1,032)	(817)	(447)	(347)	(306)
	K19 Imp C31 750mw	(629)	(572)	(437)	(376)	(344)
	K19 Imp Gas 750mw	(249)	(216)	(161)	(107)	(70)
2038	All Gas	123	248	321	331	389
	K22 Gas	(38)	16	30	51	239
	Gas C26	(88)	(24)	3	79	195
	K19 Gas 250mw	(11)	33	89	172	243
	K19 C25 250mw	(400)	(364)	(269)	(244)	(198)
	K19 Exp C25 750mw	(487)	(406)	(291)	(227)	(221)
	K19 Imp C31 750mw	(542)	(487)	(382)	(312)	(266)
	K19 Imp Gas 750mw	138	237	316	384	442
2041	All Gas	(85)	59	100	156	228
	K22 Gas	151	197	227	385	508
	Gas C26	111	253	288	356	425
	K19 Gas 250mw	190	200	243	435	514
	K19 C25 250mw	(222)	(214)	(178)	(100)	(70)
	K19 Exp C25 750mw	(19)	(10)	7	103	287
	K19 Imp C31 750mw	(178)	(25)	(5)	99	121
	K19 Imp Gas 750mw	(203)	(175)	(85)	(1)	71
2044	All Gas	112	193	334	421	603
	K22 Gas	(53)	84	224	286	402
	Gas C26	(151)	(115)	(100)	(32)	157
	K19 Gas 250mw	22	99	224	418	534
	K19 C25 250mw	(256)	(211)	(152)	(25)	51
	K19 Exp C25 750mw	(286)	(214)	(147)	(16)	25
	K19 Imp C31 750mw	(287)	(237)	(192)	(77)	2
	K19 Imp Gas 750mw	51	190	238	420	652
2047	All Gas	(125)	(75)	(24)	123	164
	K22 Gas	(270)	(225)	(198)	(145)	(15)
	Gas C26	(406)	(323)	(236)	(184)	(151)
	K19 Gas 250mw	(368)	(257)	(173)	(12)	4
	K19 C25 250mw	(244)	(195)	(97)	(24)	(14)
	K19 Exp C25 750mw	(327)	(195)	(75)	(14)	5
	K19 Imp C31 750mw	(491)	(444)	(432)	(373)	(269)
	K19 Imp Gas 750mw	(255)	(209)	(187)	(29)	14

Projected Borrowings
(net of long term debt retirements and sinking fund transactions)

Fiscal Year Ending	Development Plan	P10	P25	P50	P75	P90
2050	All Gas	(495)	(460)	(267)	(149)	(29)
	K22 Gas	(343)	(295)	(188)	(70)	(28)
	Gas C26	(537)	(328)	(274)	(184)	(72)
	K19 Gas 250mw	(535)	(320)	(248)	(120)	(26)
	K19 C25 250mw	(353)	(339)	(299)	(219)	(114)
	K19 Exp C25 750mw	(468)	(306)	(276)	(215)	(70)
	K19 Imp C31 750mw	(1,102)	(897)	(791)	(674)	(597)
	K19 Imp Gas 750mw	(305)	(282)	(264)	(176)	(59)
2053	All Gas	(248)	(174)	(78)	(22)	42
	K22 Gas	(642)	(296)	(221)	(151)	13
	Gas C26	(268)	(256)	(118)	(40)	(10)
	K19 Gas 250mw	(286)	(222)	(213)	(152)	22
	K19 C25 250mw	(662)	(585)	(290)	(258)	(197)
	K19 Exp C25 750mw	(650)	(415)	(285)	(266)	(207)
	K19 Imp C31 750mw	(835)	(517)	(471)	(430)	(310)
	K19 Imp Gas 750mw	(376)	(258)	(227)	(173)	(155)
2056	All Gas	(439)	(393)	(265)	(176)	(61)
	K22 Gas	(622)	(476)	(382)	(236)	(120)
	Gas C26	(507)	(442)	(391)	(275)	(232)
	K19 Gas 250mw	(525)	(419)	(303)	(201)	(156)
	K19 C25 250mw	(1,588)	(1,047)	(684)	(270)	(165)
	K19 Exp C25 750mw	(1,372)	(1,050)	(717)	(276)	(134)
	K19 Imp C31 750mw	(605)	(543)	(410)	(228)	(199)
	K19 Imp Gas 750mw	(395)	(332)	(201)	(80)	105
2059	All Gas	(153)	(61)	15	200	398
	K22 Gas	(304)	(141)	(25)	154	239
	Gas C26	(607)	(489)	(434)	(411)	(353)
	K19 Gas 250mw	(278)	(201)	(76)	57	250
	K19 C25 250mw	(572)	(514)	(437)	(394)	(218)
	K19 Exp C25 750mw	(611)	(526)	(442)	(236)	(216)
	K19 Imp C31 750mw	(778)	(659)	(500)	(457)	(365)
	K19 Imp Gas 750mw	(514)	(439)	(371)	(257)	(178)
2062	All Gas	(626)	(560)	(411)	(383)	(230)
	K22 Gas	(90)	107	220	666	1,138
	Gas C26	(636)	(616)	(568)	(418)	(340)
	K19 Gas 250mw	(300)	(239)	(50)	204	219
	K19 C25 250mw	(629)	(492)	(440)	(305)	(200)
	K19 Exp C25 750mw	(585)	(549)	(442)	(203)	(122)
	K19 Imp C31 750mw	(302)	(171)	(10)	76	214
	K19 Imp Gas 750mw	(286)	(199)	(55)	209	353

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.3; Page No.: 13

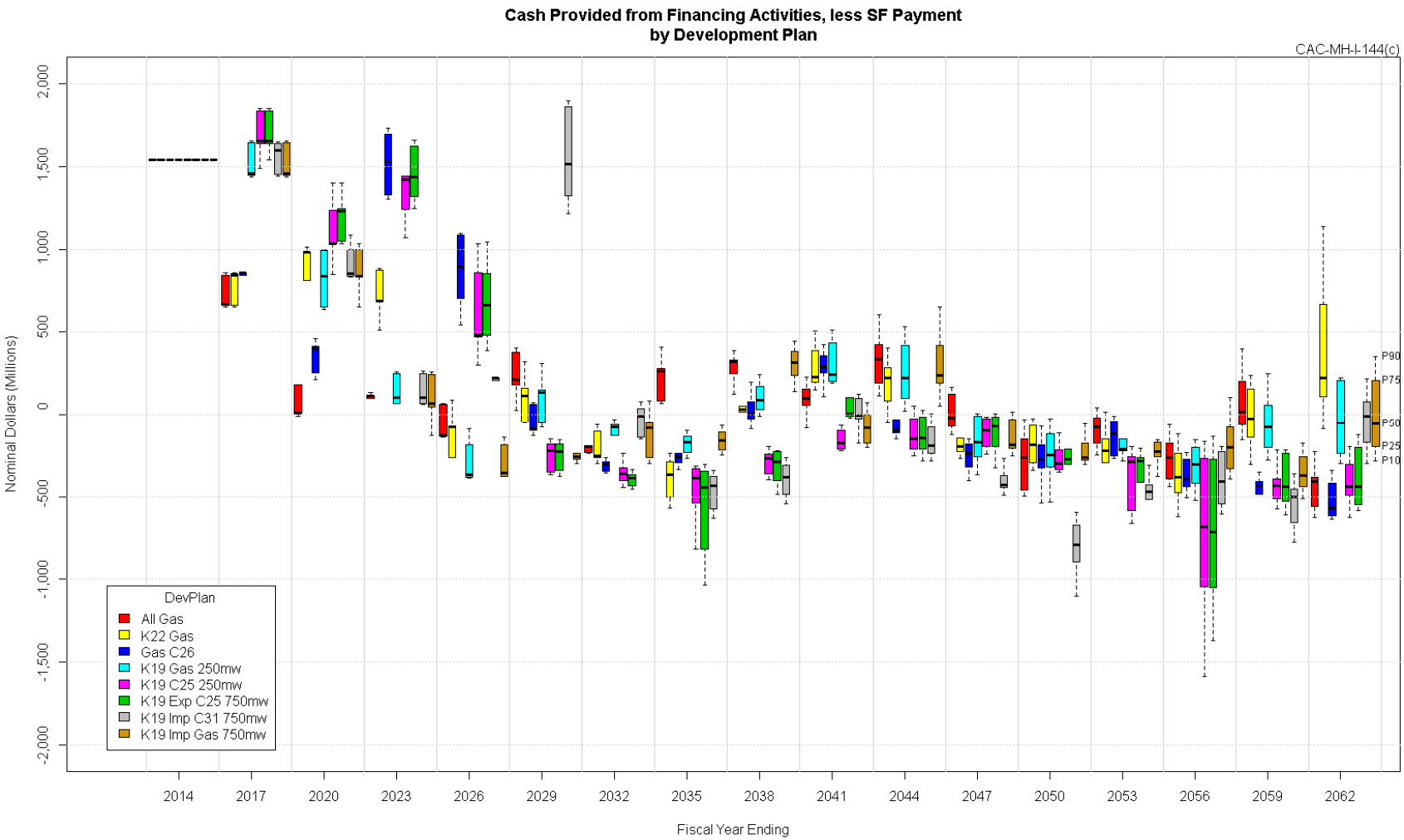
QUESTION:

Please provide a graphic similar to Figure 11.4 but based on annual borrowing as opposed to net debt.

RESPONSE:

The following plot provides the Figure 11.4 with projected borrowings (net of long term debt retirements and sinking fund transactions) for the values corresponding with P10/P25/P50/P75/P90.

1


Cash Provided from Financing Activities, less SF Payment
by Development Plan
CAC-MH-I-144(c)
Nominal Dollars (Millions)
2,000
1,500
1,000
500
0
-500
-1,000
-1,500
-2,000
2014
2017
2020
2023
2026
2029
2032
2035
2038
2041
2044
2047
2050
2053
2056
2059
2062
Fiscal Year Ending
P90
P75
P50
P25
P10
DevPlan
All Gas
K22 Gas
Gas C26
K19 Gas 250mw
K19 C25 250mw
K19 Exp C25 750mw
K19 Imp C31 750mw
K19 Imp Gas 750mw

2

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.3; Page No.: 16

QUESTION:

Has Manitoba Hydro reviewed the projected financial requirements and financial metrics of the various developments plans with its credit rating agencies? If yes, what has been their reaction as to whether the plans could impact the Corporation's or the Province's credit ratings?

RESPONSE:

Manitoba Hydro has reviewed the projected financial requirements and financial metrics of the Preferred Development Plan with the credit rating agencies as it was forecasted within IFF12.

There are a multitude of potential factors that may impact the credit ratings and the cost of debt to the Province of Manitoba within the financial markets. For example, the credit rating agencies identify numerous rating considerations and factors within their reports (for the credit rating reports for the Manitoba Hydro-Electric Board and the Province of Manitoba, please see the response to PUB/MH I-085(a)-(b)). The causal role, if any, associated with Manitoba Hydro's capital investment program upon the future credit ratings and the cost of debt is indeterminable.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.3; Page No.: 16

QUESTION:

Is it acceptable to the credit rating agencies, Manitoba Hydro's lenders and the provincial government for Manitoba Hydro to have a debt/equity ratio in excess of 85% for more than 10 consecutive years? Please provide any comments from credit rating agencies and lenders that support your contention.

RESPONSE:

For credit rating agency comments regarding Manitoba Hydro's debt/equity ratio, please see the response to PUB/MH I-0085(a)-(b) for the credit rating reports for the Manitoba Hydro-Electric Board and the Province of Manitoba. Notable excerpts from the Manitoba Hydro reports are as follows:

DBRS: "Continued significant capex levels are expected to lead to an increase in debt levels, which will likely cause credit metrics to decline moderately over the medium term." [DBRS report on the Manitoba Hydro-Electric Board dated September 16, 2013; page 1]

S&P: "We believe Manitoba Hydro's monopoly, gas and electric franchises, and related regulatory frameworks provide satisfactory cash flow stability. Furthermore, the utility's owner, Manitoba, strongly supports its creditworthiness. In our opinion, exposure to significant hydrology risk and its highly leveraged financial risk profile offset these strengths." [S&P report on the Manitoba Hydro-Electric Board dated September 11, 2013; page 2]

Moody's: "Given the uptick in capex and corresponding debt, financial metrics are predicted to fall below targets in the next three fiscal years. The equity ratio, in particular, will

be challenged and not likely to return to target until FY2032. The weakening financial profile restricts financial flexibility and adds risk in case of unexpected events such as low water levels, cost overruns and construction delays, given the nature of a hydroelectric plant's long construction cycle before cash generating begins. However, we view Manitoba Hydro as being capable of prudently managing debt and mitigating such risks by seeking rate increases and curtailing capital spending to continue as a self-supporting corporation." [Moody's Investors Service report on the Manitoba Hydro-Electric Board dated September 23, 2013; page 2]

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.1; Page No.: 4

QUESTION:

Please provide Manitoba Hydro's most recent analysis/review confirming the appropriateness of a target 75:25 debt: equity ratio.

RESPONSE:

The Manitoba Hydro-Electric Board reaffirmed Manitoba Hydro's existing targets for debt/equity (75:25), interest coverage (>1.20) and capital coverage (>1.20) in November 2012 based on the projections included in the 2012 Integrated Financial Forecast (IFF12).

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.4; Page No.: 20

QUESTION:

Please re-do Figure 11.8 setting out the incremental retained earnings impacts as a percent of retained earnings at the start of the drought period.

RESPONSE:

Please see response to MIPUG/MH I-6(c)(ii).

REFERENCE: Appendix A Integrated Financial Forecast (IFF12); Page No.: 33

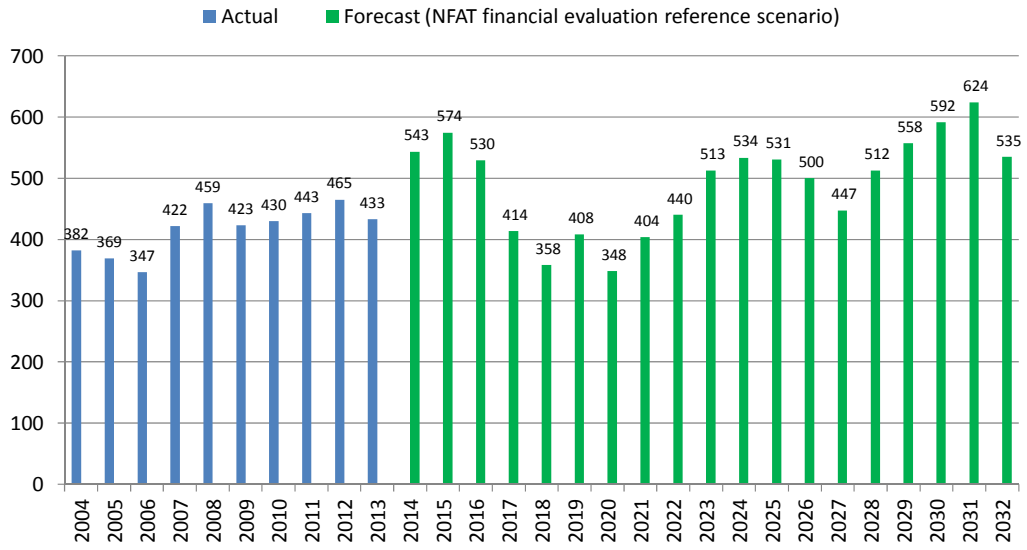
QUESTION:

Please provide a schedule that sets out Manitoba Hydro's historic annual capital spending over the past 10 years and projected through to 2032 on projects other than Major New Generation and Transmission.

RESPONSE:

The following graph shows Manitoba Hydro's historic annual capital spending over the past 10 years, as well as projected annual capital expenditures of Manitoba Hydro's base capital (projects other than Major New Generation and Transmission) under the reference scenario.

Electricity Base Capital Expenditures
For the year ended March 31
millions of dollars



REFERENCE: Appendix A Integrated Financial Forecast (IFF12); Page No.: 33

QUESTION:

Has Manitoba Hydro undertaken any assessment as to the degree of uncertainty associated with its projected capital requirements for purposes other than major New Generation and Transmission?

RESPONSE:

The identification of the Corporation's planned financial support for its aging infrastructure requirements are described in the Capital Expenditure Forecast (CEF) which is updated an annual basis.

Manitoba Hydro makes ongoing capital investments in its existing system. To further support this commitment, over the last several years, Manitoba Hydro has also initiated an extensive review of its existing assets. During this review, work has begun to develop models and capabilities to methodically undertake condition assessments and to determine long term replacement plans for its assets on a prioritized basis.

REFERENCE: Chapter 12: Economic Evaluations - 2013 Update On Selected Development Plans; Section: 12.1.2; Page No.: 4

QUESTION:

Is the reduction in DSM due to the reduction in the Load Forecast or as a result of other factors? If other factors, please explain what they are.

RESPONSE:

The reduction in DSM is due to a change in the forecast DSM energy and capacity savings in the updated 2013-2016 Power Smart Plan. The differences in energy and capacity savings are primarily due to both decreases and increases in energy savings for programs due to modifications to the program offering based on updated market activity (e.g. changes to participation, product mix, etc.) and exclusion of potential new programs (i.e. programs added as placeholders and which may be subject to further assessment and approvals). For information on the key differences in expected energy and demand savings, please refer to the responses to PUB/MH I-214(d) and PUB/MH I-214(b) respectively.

REFERENCE: Chapter 12: Economic Evaluations - 2013 Update On Selected Development Plans; Section: 12.1.7; Page No.: 8

QUESTION:

Please provide the equivalent to Appendix 11.2 based on the 2013 Update.

RESPONSE:

The following table provides a comparison between the economic indicator assumptions used in the Reference Scenario (Chapter 9) and 2013 Update (Chapter 12) economic analyses.

Comparison of the Projected Economic Variables
Reference Scenario

2012 Assumptions (Chapter 9)

Fiscal Year Ending	2013	2014	2015	2016	2017	2018	2019	2020 & on
Cdn GDP Deflator - % chg	1.90	2.00	2.20	1.80	1.80	1.80	1.80	1.80
US GDP Deflator - % chg	1.60	1.80	2.00	1.80	1.80	1.80	1.80	1.80
US - Cdn Exchange Rate (Cdn $/US $)	1.00	0.99	1.02	1.03	1.04	1.04	1.04	1.04
Real Weighted Avg. Cost of Capital (%)	<----------	----------	----------	----------	5.05	----------	----------	---------->

2013 Update (Chapter 12)

Fiscal Year Ending	2014	2015	2016	2017	2018	2019	2020 & on
Cdn GDP Deflator - % chg	1.80	1.80	1.80	1.80	1.90	1.90	1.90
US GDP Deflator - % chg	1.90	2.10	1.90	2.00	2.00	2.00	1.90
US - Cdn Exchange Rate (Cdn $/US $)	1.02	1.01	1.01	1.03	1.03	1.03	1.03
Real Weighted Avg. Cost of Capital (%)	<----------	----------	----------	5.40	----------	----------	---------->

REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates; Page No.: 27

QUESTION:

Please provide the capital cost of the 250 and 750 MW interconnection in a similar format (i.e., Base Estimate, Escalation and Capitalized Interest) as set out in Table 3 for Keeyask and Conawapa. In each case, please show the cost of the US and Manitoba portions separately.

RESPONSE:

The attached schedules provide a breakdown of the capital costs for the 250MW and 750MW interconnections. The costs of the Manitoba portion and US portion (where applicable) have been shown separately.

Capital Costs of the 250 MW Interconnection
Manitoba Portion
Development Plans: K19 Gas 250 MW, K19 C25 250 MW
(In Millions of Dollars)

Economics:	**Reference**
Market Prices:	**Reference**
Capital Costs:	**Reference**

Fiscal Year Ending	Spent to Date	2012 Constant Dollar Cash Flows	Capitalized Interest	Escalation	Total
2012	1	-	-	-	1
2013	-	0	0	-	0
2014	-	3	0	0	3
2015	-	4	0	0	4
2016	-	3	1	0	3
2017	-	4	1	0	5
2018	-	6	1	1	8
2019	-	17	2	2	21
2020	-	17	3	3	23
2021	-	18	5	3	26
2022	-	-	-	-	-
2023	-	-	-	-	-
2024	-	-	-	-	-
2025	-	-	-	-	-
2026	-	-	-	-	-
2027	-	-	-	-	-
2028	-	-	-	-	-
2029	-	-	-	-	-
2030	-	-	-	-	-
2031	-	-	-	-	-
2032	-	-	-	-	-
2033	-	-	-	-	-
2034	-	-	-	-	-
2035	-	-	-	-	-
2036	-	-	-	-	-
2037	-	-	-	-	-
2038	-	-	-	-	-
2039	-	-	-	-	-
2040	-	-	-	-	-
2041	-	-	-	-	-
2042	-	-	-	-	-
2043	-	-	-	-	-
2044	-	-	-	-	-
2045	-	-	-	-	-
2046	-	-	-	-	-
2047	-	-	-	-	-
2048	-	-	-	-	-
2049	-	-	-	-	-
2050	-	0	0	0	0
2051	-	0	0	0	1
2052	-	1	0	1	2
2053	-	1	0	2	3
2054	-	4	1	5	10
2055	-	4	1	5	11
2056	-	4	2	6	12
2057	-	-	-	-	-
2058	-	-	-	-	-
2059	-	-	-	-	-
2060	-	-	-	-	-
2061	-	-	-	-	-
2062	-	-	-	-	-
Total	**1**	**86**	**18**	**29**	**134**

Capital Costs of the 750 MW Interconnection
Manitoba Portion
Development Plans: K19 Sales C25 750 MW,
K19 Imp C31 750 MW & K19 Imp Gas 750 MW
(In Millions of Dollars)

Economics:	**Reference**
Market Prices:	**Reference**
Capital Costs:	**Reference**

Fiscal Year Ending	Spent to Date	2012 Constant Dollar Cash Flows	Capitalized Interest	Escalation	Total
2013	1	0	0	-	1
2014	-	0	0	-	0
2015	-	3	0	0	3
2016	-	5	0	0	6
2017	-	16	1	1	19
2018	-	24	3	3	29
2019	-	72	6	10	88
2020	-	72	12	11	95
2021	-	75	3	13	91
2024	-	-	-	-	-
2025	-	-	-	-	-
2026	-	-	-	-	-
2027	-	-	-	-	-
2028	-	-	-	-	-
2029	-	-	-	-	-
2030	-	-	-	-	-
2031	-	-	-	-	-
2032	-	-	-	-	-
2033	-	-	-	-	-
2034	-	-	-	-	-
2035	-	-	-	-	-
2036	-	-	-	-	-
2037	-	-	-	-	-
2038	-	-	-	-	-
2039	-	-	-	-	-
2040	-	-	-	-	-
2041	-	-	-	-	-
2042	-	-	-	-	-
2043	-	-	-	-	-
2044	-	-	-	-	-
2045	-	-	-	-	-
2046	-	-	-	-	-
2047	-	-	-	-	-
2048	-	-	-	-	-
2049	-	-	-	-	-
2050	-	1	0	1	1
2051	-	1	0	1	3
2052	-	4	0	4	9
2053	-	6	1	7	14
2054	-	18	3	21	42
2055	-	18	5	22	45
2056	-	18	1	24	43
2057	-	-	-	-	-
2058	-	-	-	-	-
2059	-	-	-	-	-
2060	-	-	-	-	-
2061	-	-	-	-	-
Total	**1**	**333**	**35**	**118**	**488**

Capital Costs of the 750 MW Interconnection
US Portion with WPS Sale
Development Plan: K19 Sales C25 750 MW
(In Millions of Dollars)

Economics:	**Reference**
Market Prices:	**Reference**
Capital Costs:	**Reference**

Fiscal Year Ending	Spent to Date	2012 Constant Dollar Cash Flows	Capitalized Interest	Escalation	Total
2012	-	-	-	-	-
2013	-	-	-	-	-
2014	-	-	-	-	-
2015	-	1	0	0	1
2016	-	1	0	0	1
2017	-	0	0	0	1
2018	-	-	0	-	0
2019	-	27	1	4	32
2020	-	10	3	2	14
2021	-	77	1	14	91
2022	-	-	-	-	-
2023	-	-	-	-	-
2024	-	-	-	-	-
2025	-	-	-	-	-
2026	-	-	-	-	-
2027	-	-	-	-	-
2028	-	-	-	-	-
2029	-	-	-	-	-
2030	-	-	-	-	-
2031	-	-	-	-	-
2032	-	-	-	-	-
2033	-	-	-	-	-
2034	-	-	-	-	-
2035	-	-	-	-	-
2036	-	-	-	-	-
2037	-	-	-	-	-
2038	-	-	-	-	-
2039	-	-	-	-	-
2040	-	-	-	-	-
2041	-	-	-	-	-
2042	-	-	-	-	-
2043	-	-	-	-	-
2044	-	-	-	-	-
2045	-	-	-	-	-
2046	-	-	-	-	-
2047	-	-	-	-	-
2048	-	-	-	-	-
2049	-	-	-	-	-
2050	-	-	-	-	-
2051	-	-	-	-	-
2052	-	-	-	-	-
2053	-	-	-	-	-
2054	-	-	-	-	-
2055	-	-	-	-	-
2056	-	-	-	-	-
2057	-	-	-	-	-
2058	-	-	-	-	-
2059	-	-	-	-	-
2060	-	-	-	-	-
2061	-	-	-	-	-
2062	-	-	-	-	-
Total	**-**	**117**	**5**	**19**	**141**

Capital Costs of the 750 MW Interconnection

US Portion without WPS Sale
Development Plans:
K19 Imp C31 750 MW & K19 Imp Gas 750 MW
(In Millions of Dollars)

Economics: Reference
Market Prices: Reference
Capital Costs: Reference

Fiscal Year Ending	Spent to Date	2012 Constant Dollar Cash Flows	Capitalized Interest	Escalation	Total
2013	-	-	-	-	-
2014	-	-	-	-	-
2015	-	2	0	0	3
2016	-	3	0	0	3
2017	-	1	0	0	2
2018	-	-	0	-	0
2019	-	69	3	9	80
2020	-	25	6	4	35
2021	-	193	1	34	229
2022	-	-	-	-	-
2023	-	-	-	-	-
2024	-	-	-	-	-
2025	-	-	-	-	-
2026	-	-	-	-	-
2027	-	-	-	-	-
2028	-	-	-	-	-
2029	-	-	-	-	-
2030	-	-	-	-	-
2031	-	-	-	-	-
2032	-	-	-	-	-
2033	-	-	-	-	-
2034	-	-	-	-	-
2035	-	-	-	-	-
2036	-	-	-	-	-
2037	-	-	-	-	-
2038	-	-	-	-	-
2039	-	-	-	-	-
2040	-	-	-	-	-
2041	-	-	-	-	-
2042	-	-	-	-	-
2043	-	-	-	-	-
2044	-	-	-	-	-
2045	-	-	-	-	-
2046	-	-	-	-	-
2047	-	-	-	-	-
2048	-	-	-	-	-
2049	-	-	-	-	-
2057	-	-	-	-	-
2058	-	-	-	-	-
2059	-	-	-	-	-
2060	-	-	-	-	-
2061	-	-	-	-	-
2062	-	-	-	-	-
Total	**-**	**293**	**12**	**47**	**352**

REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates; Page No.: 27

QUESTION:

Is the cost of the 750 MW US interconnection the same after the 2013 Update assuming the in-service date is unchanged? If not, please provide a revised response to part a).

RESPONSE:

The base cost estimate for the US portion of the 750 MW US interconnection in the 2012 analysis is the same as the 2013 Update. The base cost estimate for the Manitoba portion was updated for the 2013 Update.

Changes to the treatment of real escalation for the US portion of the 750 MW US interconnection resulted in a reduction in the estimated total project cost in 2014$.

The updated base cost estimate for the Manitoba portion of the 750 MW US interconnection included a change in the capital cost distribution. The change in capital cost distribution also resulted in a small sunk cost to be removed from the cashflow in the economic analysis as a cost spent prior to June 2014.

The following tables include the base cost estimates (2014$) included in the 2012 and 2013 updates for the costs for which Manitoba Hydro would be responsible under the Preferred Development Plan.

The in-service costs, including interest and escalation, are not available for the 2013 Update capital costs as financial analysis was not completed for any of the 2013 update information.

750 MW US Interconnection 2012

Capital & Related Costs (Millions of 2014$)		
	Transmission	
FYB	US Portion of Transmission Line	Manitoba Portion of Transmission Line
2013		
2014	1.00	2.77
2015	1.21	5.55
2016	0.52	16.64
2017	0.00	24.95
2018	28.48	74.86
2019	10.30	74.86
2020	80.22	77.63
2021		
Total	121.73	277.26

750 MW US Interconnection 2013 Update

Capital & Related Costs (Millions of 2014$)		
	Transmission	
FYB	US Portion of Transmission Line	Manitoba Portion of Transmission Line
2013		
2014	0.99	17.83
2015	1.17	3.57
2016	0.50	27.99
2017	0.00	92.73
2018	26.49	46.24
2019	9.43	46.21
2020	72.31	36.65
2021	0.00	0.40
Total	110.90	271.61

REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates; Page No.: 27

QUESTION:

Is the cost of the 250 MW US interconnection the same after the 2013 Update assuming the in-service date is unchanged? If not, please provide a revised response to part a).

RESPONSE:

The Manitoba and U.S. base cost assumption of the 250 MW U.S. interconnection in the analysis based on 2012 assumptions is the same as the 2013 Update. For the 2013 Update, the Canadian portion of the interconnection had an additional $2.80 million in sunk costs as compared to the analysis based on the 2012 assumptions..

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.1.1; Page No.: 2

QUESTION:

Please provide a link to or a copy of the Marvin Shaffer paper - Multiple Account Benefit-Cost Analysis.

RESPONSE:

The book *Multiple Account Benefit-Cost Analysis* was published by University of Toronto Press in 2010. It can be purchased from the publisher, some university bookstores or through amazon.ca.

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.1.1; Page No.: 2

QUESTION:

Please provide a link to or a copy of the Treasury Board of Canada document referred to in footnote #2.

RESPONSE:

The link to the Treasury Board Secretariat Guidelines is: http://www.tbs-sct.gc.ca/rtrap-parfa/analys/analystb-eng.asp.

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis.

QUESTION:

Please provide a copy of Dr. Shaffer's CV and list any regulatory proceedings in which he has given expert evidence.

RESPONSE:

Dr. Shaffer's resume and list of assignments is attached. He has appeared in hearings before the National Energy Board, BC Utilities Commission, Manitoba Clean Environment Commission, and Canadian and joint federal-provincial Environmental Assessment panels.

MSA

Marvin Shaffer & Associates Ltd.
Consulting Economists

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MARVIN SHAFFER & ASSOCIATES LTD.

Marvin Shaffer & Associates Ltd. (MSA) is a British Columbia-based consulting firm which specializes in energy, transportation and natural resource economics, as well as general project and economic policy analysis. In all undertakings, the primary objective is to apply sound economic principles and theory to practical problems in a rigorous yet readily comprehensible manner.

Dr. Marvin Shaffer, the principal consultant, has a Ph.D. in Economics from the University of British Columbia. He received his B.A., Honours in Economics, from McGill University. Dr. Shaffer has managed MSA for over thirty years, undertaking consulting assignments for both public and private sector clients across Canada. He has successfully negotiated major agreements in the energy and transportation fields. He has held senior positions with the Government of British Columbia (head of the Crown Corporations Secretariat and Chief Executive Officer of the British Columbia Transportation Financing Authority). Dr. Shaffer is currently an Adjunct Professor in the Public Policy program at Simon Fraser University, lecturing on multiple account benefit-cost analysis. As well, he has lectured in economics at the University of British Columbia, and the University of Queensland and the University of Tasmania in Australia.

Dr. Shaffer's resume and a list of representative clients are attached.

MARVIN SHAFFER, Ph.D.

RÉSUMÉ

DATE OF BIRTH: May 1, 1949

PLACE OF BIRTH: Winnipeg, Manitoba

CITIZENSHIP: Canadian

EDUCATION: McGill University, Montreal, Quebec
B.A. (Honours) Economics, 1970.

University of British Columbia, Vancouver, B.C.
Ph.D. Economics, 1974.
Ph.D. Dissertation Topic: The Role of Competition in Macro Models
Areas of Specialization: Industrial Organization - Labour Economics

AWARDS: Woodrow Wilson Fellowship, 1970
U.B.C. Fellowships, 1970-1972
Canada Council Fellowships, 1972-1974

MAJOR ACCOMPLISHMENTS:

- ***Greater Vancouver Transportation Authority:***
  - Negotiated agreement and co-chaired transition team transferring responsibility for BC Transit from the Province to Greater Vancouver within a newly created multi-modal, integrated transportation authority.

- ***Columbia River Treaty:***
  - Negotiated agreements for the return of the power benefits owed to British Columbia under the ***Columbia River Treaty*** in a manner which minimizes transmission costs and maximizes market opportunities for the province.

- ***Multiple Account Benefit-Cost Analysis:***
  - Developed framework now widely used within British Columbia for the evaluation of major policies and projects, recognizing financial, customer service, environmental and economic development objectives of government.

  - Wrote a book for students and practitioners ***Multiple Account Benefit-Cost Analysis: A Practical Guide for the Systematic Evaluation of Project and Policy Alternatives***, published by University of Toronto Press in 2010.

EMPLOYMENT:

1976-1992, 1995-Present	***Consulting Economist*** - President and senior consultant for Marvin Shaffer & Associates Ltd., a consulting firm specializing in energy, transportation and environmental economics.
2004-Present	***Adjunct Professor, Public Policy Program, Simon Fraser University*** **–** lecture on benefit-cost analysis.
1987, 1989, 1997-2003	***Sessional Lecturer in Economics, University of British Columbia*** **-** macroeconomics and benefit-cost analysis.
1985,1988,1992,2000,2003	***Visiting Senior Lecturer in Economics, University of Tasmania and University of Queensland*** -Lectured in benefit-cost analysis, natural resource economics, macroeconomics, econometrics and other subjects.
June 1994-June 1995	***Chief Executive Officer, British Columbia Transportation Financing Authority***, a Crown corporation responsible for integrated transportation planning and the financing of provincial highway and other transportation infrastructure investments.
Aug. 1993-June 1995	***Secretary Responsible for the British Columbia Crown Corporations Secretariat***, a central agency responsible for reviewing strategic and business plans, and monitoring the performance of British Columbia's Crown corporations.
June 1992-Aug. 1993	***Assistant Secretary, Capital Evaluation and Economic Analysis, British Columbia Crown Corporations Secretariat*** -- Developed Multiple Account Guidelines for British Columbia's Crown corporations to ensure systematic evaluation of major investments; served as British Columbia's Chief Negotiator for the return of the Downstream Benefits owed to British Columbia under the Columbia River Treaty.
1976-present	***Freelance Writer*** **-** Freelance writer on economics and energy issues for major newspapers in Western Canada
1974-1976	***Senior Economist, B.C. Energy Commission*** - Researched and prepared reports on a wide range of energy topics, including future energy demand, utility rate structure, energy supply, field pricing and resource taxation.

MARVIN SHAFFER & ASSOCIATES LTD.

REPRESENTATIVE CLIENTS

Governments

Federal
Auditor General
Employment and Immigration Canada
Energy, Mines & Resources Canada
External Affairs
Finance
Fisheries & Oceans Canada
Health & Welfare Canada
Indian and Northern Affairs
Public Works Canada
Science Council of Canada
Transport Canada

Provincial
Province of British Columbia
- Crown Corporations Secretariat
- Environment & Land Use Secretariat
- Marine Resources Branch
- Ministry of Agriculture
- Ministry of Economic Development
- Ministry of Employment and Investment
- Ministry of Energy, Mines & Petroleum Resources
- Ministry of Environment
- Ministry of Forests
- Ministry of Lands, Parks & Housing
- Ministry of Social Services & Housing

Government of the Northwest Territories
Manitoba Energy Authority
Yukon Territorial Government

Other
City of Kitimat
City of Surrey
Greater Vancouver Regional District
GVTA (Translink)

Public Sector / Crown Corporations

B.C. Ferries
B.C. Hydro
B.C. Resources Investment Corp.
B.C. Transportation Financing Authority
Columbia Power Corporation
Manitoba Hydro
New Brunswick Electric Power Commission
Ontario Waste Management Corporation
Partnerships B.C.
Powerex
Saskatchewan Crown Investments Corporation
Saskatchewan Power Corporation
Vancouver Public Library

Indian Organizations

Ft. Nelson Indian Band
Gitxsan Tribal Coucil
Lake Babine Band
Lax Kw'alaams Indian Band
Musqueam Indian Band
Nisga'a Tribal Council
Katzie First Nation
Tahltan Tribal Council

Public Task Forces and Inquiries

B.C.-Environment Assessment Office
- Salmon Aquaculture Review

B.C.-Gasoline Pricing Inquiry
B.C.-Port Hardy Ferrochrominium Review Panel
B.C.-States Oil Spills Task Force
B.C. Utilities Commission
Ontario Energy Board
West Coast Oil Ports Inquiry
Western Grid Study Agreement

Private Sector Firms and Associations

Alcan Ltd.
Amoco Canada Ltd.
Arlon Tussing & Associates
Berger & Nelson, Barristers & Solicitors
BC Gas
Cassels, Brock & Blackwell, Barristers & Solicitors
Golder & Associates
Gulf Canada Ltd.
Industrial Gas Users Associaton
Inland Pacific Energy Services (B.C. Gas)
Mobil Oil Inc.
Monenco Consultants Ltd.
Montenay Inc
Natural Gas Pipeline Company of America
Niagara Mohawk Power Corporation
Petro-Canada Inc.
Progas Limited
RBC Dominion Securities
Reid Crowther & Partners Inc.
Sandwell, Swan Wooster
Shell Canada Ltd.
SNC Lavalin
Westcoast Transmission Ltd.
Western Gas Marketing Limited

Non-Profit Organizations

BC Public Interest Advocacy Centre
Canada West Foundation
Canadian Wildlife Service
Canadian Energy Research Institute
Friends of Nemaiah Valley
YWCA

MSA

ASSIGNMENTS COMPLETED SINCE 1990

Energy

AECOM:-Analyzed the economics of alternative waste management strategies in MetroVancouver, including waste-to-energy plants, 1999.

BC Gas:- Analyzed the implications and provided policy advice on alternative regulatory policies respecting the pricing of natural gas and electricity, 2000-2001.

BC Hydro:-With Alchemy Consulting and Constable Consultants, analyzed the opportunities and economic efficiency of NOx offset measures for the Burrard Thermal Power plant, 1999.

_____:- Prepared a report on the implications of commitments in the B.C. government's New Era document in relation to the Burrard Thermal plant, and reviewed and helped draft a response to a critique of BC Hydro's proposed Vancouver Island gas pipeline, 2001.

BC Ministry of Employment and Investment:- Provided advice on long term sales opportunities for the downstream power benefits owed to the province under the Columbia River Treaty. Also advised on the costs and benefits of long term power sales to proposed aluminum smelters in the province, 2001.

_____:- Analyzed the economic implications for the energy and mines sectors in a multiple account evaluation of alternative Mackenzie area land and resource management plans, 2000.

_____:- Reviewed analyses of the economic impacts, costs and benefits to the province and BC Hydro of a proposed aluminum smelter at Port Alberni, 2001.

BC Ministry of Energy, Mines and Petroleum Resources:- Acted as an advisor in the preparation of MEMPR's Energy Policy Paper "Our Energy Future", March, 1991.

____:- Prepared a report "Integrating Environmental and Energy Values -- An Economic Perspective on Energy Policy for the 90's", April, 1990.

____:- Prepared a report "Environmental and Economic Issues Related to Fuel Choice in Space and Water Heating in British Columbia", December, 1990.

BC Ministry of Environment, Lands & Parks:- Undertook a study entitled "Supply and Price Impact of Cleaner Gasoline Standards in British Columbia" 1995.

BC Ministry of Finance:- With Alchemy Consulting and Constable Consultants, prepared a multiple account benefit-cost evaluation of alternative strategies with respect to the operation or closure of the Burrard Thermal Power plant, 2000-2001.

BC Ministry of Small Business and Economic Development:- Prepared a report on the economic and social benefits associated with the development of a Cold Water Release Facility at or near Kenney Dam on the Nechako Reservoir, 2004.

BC Ministry of Water Lands and Air Protection:- Prepared a report on the economic implications of alternative Kyoto implementation scenarios on Tech Cominco's Trail smelter and Elkford mine, 2002.

BC Public Interest Advisory Centre:- Prepared a report and appeared as an expert witness on marginal cost pricing at the BCUC Hearing on BC Hydro's Rate Design Application, 2007.

____:- Prepared a report and testified at a BC Utilities Commission hearing on the rationale, impacts, economic efficiency and equity of BC Hydro's Power Smart program, 2004.

BC Utilities Commission:- Acted as Head of Inquiry Research in the BC Utility Commission Inquiry into Gasoline Pricing in British Columbia, 1996

Berger & Nelson, Barristers & Solicitors:- Reviewed and advised on a report by Fisher Energy Consultants entitled "Economics for the Development of Oil and Gas Resources in Lot 9 and 27 of the Former Fort St. John Indian Reserve No. 172" in preparation for a trial -- Apsassin v. The Queen, 1997.

Canadian Office and Professional Employees Union:- Prepared a series of policy papers *(Lost in Transmission)* critiquing the self-sufficiency, pricing and supply side provisions in the BC Government's Energy Plan, 2007.

_____:- Prepared evidence and testified as an expert at a BC Utilities Commission hearing on BC Hydro's 2008 Long Term Acquisition Plan, 2009.

City of Kitimat:- Analyzed the provisions in the BC Hydro-Alcan LTEPA+ and 2007 Energy Purchase Agreements and appeared as an expert witness at BCUC's hearings reviewing those contracts, 2006 and 2007.

Columbia Power Corporation:- Reviewed evidence and assisted in the preparation for Columbia Power's intervention at a BC Utility Commission hearing into BC Hydro's Integrated Electricity and Long Term Acquisition Plans, 2006.

_____:- Prepared a report and testified at a BC Utility Commission hearing on BC Transmission Corporation's proposed Open Access Transmission Tariff, 2005.

_____:- Analyzed the financial and environmental costs of a proposed coal-fired power plant compared to gas-fired combined cycle and hydro alternatives available in British Columbia, 1999.

_____:-Reviewed assumptions, methodology and report on a benefit-cost analysis of the Keenleyside 150 MW Power Plant project, 1998.

Electricity Table-National Climate Change Process:- Prepared a report on the environmental and health-related impacts of various options to meet target reductions in greenhouse gas emissions, 1999.

Greater Vancouver Regional District (MetroVancouver):- Reviewed existing provisions and alternatives respecting an agreement with BC Hydro to use water from the Coquitlam reservoir for domestic purposes. Prepared a report on specific alternatives for detailed discussion and negotiation with BC Hydro. Assisted in the renegotiation of the Coquitlam water purchase arrangements 2003-2006.

_____:- Provided advice on the market pricing of the electricity output from a proposed municipal waste incinerator turbogenerator project, 2001.

Inland Pacific Enterprises Corporation:- Provided strategic advice on electricity marketing, independent power project developments, public-private partnerships, and other related matters, 1995-1997

Manitoba Hydro:- Developed a multiple account framework for the analysis of alternative resource development plans, in preparation for submission to a Manitoba government Needs for and Alternative Hearing, 2011-12.

_____:- Prepared a presentation and led a workshop on Triple Bottom Line Assessment and Accounting, 2005.

_____:- Prepared a multiple account benefit-cost report on the development of a cooling tower at the Selkirk gas-fired thermal plant, 2004.

_____:- Prepared a multiple account benefit-cost comparison of developing the Wuskwatim hydro project versus a comparable amount of wind capacity, 2004.

_____:- Prepared a multiple account benefit-cost report on advancing the Wuskwatim hydro project for export, 2003

_____:- Reviewed participation and benefit agreements between energy sector companies and First Nations and advised on participation options for Manitoba Hydro's hydro projects, 2001-2006.

_____:- Prepared a contingent valuation study with the assistance of Prairie Research Associates Inc. entitled "Transmission Line Impacts on Wilderness Values – Phase III Report", March, 1992.

____:- Prepared a report "Environment and Economic Trade-Offs of Alternative Expansion Plans", March, 1990.

Mobil Oil Inc.:- With Brent Friedenberg & Associates, prepared a benefit-cost analysis and testified before an Environmental Assessment Panel on Mobil Oil's Sable Offshore Energy Project and the Maritime and Northeast Pipeline Project, 1997.

Powerex:- Chief Negotiator for the Province of British Columbia leading to agreements regarding the return of the Downstream Power Benefits under the *Columbia River Treaty*, 1995-1998.

_____:- Prepared report on the evolution of western North America electricity markets in support of an application for a provincial energy removal certificate, 1999.

____:- Facilitated discussions between Whatcom County, Intalco and Powerex leading to commercial negotiation of a power supply contract, 2001.

____:- Reviewed application of risk capital concepts to the evaluation of gas plant tolling opportunities, 2003.

____:- Helped organize workshops on risk management, trading strategies, and accountability framework presented to Hydro Tasmania Board and staff, 2003.

RBC Dominion Securities:- Assisted in the economic and financial evaluation of alternative natural gas pipeline proposals and other matters, including the restructuring of BC Hydro and proposed purchases of energy sector firms, 1999-2001.

SNC Lavalin:- Reviewed a multi-criteria analysis of power supply options in Central Equatorial Africa that SNC prepared for the World Bank, 2005.

Tsawwassen First Nation:-Prepared a multiple account benefit-cost assessment of a proposed waste-to-energy project on Tsawwassen lands, 2012.

Fisheries

British Columbia Environmental Assessment Office:- Prepared a report and advised the Salmon Farming Review Committee on the Social and Economic Impacts from Current Salmon Farming Activity in B.C., 1997.

Fisheries & Oceans Canada, Pacific Region:- Prepared a study identifying linkages between the ***Pacific Salmon Treaty*** and Salmon Rebuilding Efforts in the Pacific Northwest, 1997-1998.

_____- Participated in an evaluation of DFO's Response to the **Report of the Fraser River Sockeye Public Review Board**, 1996.

_____:-Prepared a report "Columbia River Salmon Rebuilding Program" that documented the objectives, nature and costs of United States efforts to rebuild salmon (and steelhead) in the Columbia River Basin, 1996.

____:- Together with LGL Limited prepared a report on the Evaluation Framework for the At-Sea Export Program, March, 1991.

____:- Prepared an update of the report "Long Term Salmon Price Forecasting Model," March, 1991.

____:- Prepared a report "Evaluation of Pacific Licensing, License Fee Policy and Their Impact on the Catching Power and Economic Performance of the Fleet", May, 1991.

Fisheries & Oceans Canada and Indian Affairs Canada:- Prepared a report "Potential Economic Benefits of SEP for Native Indians", April, 1990.

Musqueam Indian Band:- Prepared a report on the valuation of adverse fisheries-related impacts on the Musqueam due to a new Fraser River crossing for the RAV-Canada Line rapid transit project, 2006.

Nisga'a Tribal Council:- Assisted in the negotiations for a settlement of fisheries issues in the Nisga'a Land Claim.

____:- Prepared a report "Nisga'a Long Term Economic Development Plan", April, 1990.

Transportation

BC Ferry Corporation:- Provided advice on subsidy policy issues and rate impacts related to the possible restructuring of BC Ferries Corporation, 2002.

_____- Prepared analyses of financial and regulatory requirements for achieving commercial status for BC Ferries, 1995

_____- Prepared a report on options for an explicit BC Ferry Subsidy Policy, 1992.

BC Transportation Financing Authority:- Advised on various matters including tolling policy, revenue strategy for the Vancouver Island Highway Project, 1995-1997.

Canada Ministry of Finance, Personal Income Tax Division:- Prepared a report and workshop presentation on the price elasticity of transit demand and the impacts of transit benefit tax exemptions on transit's market share, 2005.

City of Coquitlam:- Reviewed terms of access agreements in the development of the Millenium Skytrain line, 2000.

Greater Vancouver Transportation Authority:- Presented a two-day workshop on Multiple Account Benefit-Cost Analysis of major transportation projects, January, 2008.

_____:- Led technical team analyzing the feasibility, desirability, financing and implementation strategy for a new crossing of the Fraser River, 2000-2002.

_____:- Prepared paper on bus service delivery options to improve cost effectiveness and performance, 2001.

_____:- Prepared paper on the economic efficiency, potential revenues, administrative complexity and other characteristics of alternative pricing and taxation options available under the GVTA Act, 1999.

Greater Vancouver Regional District:- Co-Chaired GVTA Transition Team responsible for implementing the GVTA agreement and ***Greater Vancouver Transportation Authority Act***, 1998

_____:- Chief Negotiator for the GVRD leading to agreements creating the Greater Vancouver Transportation Authority, 1997-1998.

General Resource/ Other

BC Ministry of Agriculture and Fish:- Prepared an analysis of the principles and limitations of policy proposals to provide payments in recognition of the ecological goods and services generated by the agriculture sector, 2005.

____:- Prepared an assessment of the underlying factors and policy implications of farm income trends in British Columbia and Canada, 2005-6.

BC Ministry of Environment:- Prepared an assessment and testified at Environmental Assessment Hearings on the social and environmental impacts of a ferrochromium plant proposed by Sherwood Metallurgical British Columbia Corporation for the Port Hardy Review Panel, 1992.

____:- Prepared an evaluation of an expanded deposit/refund system and the Blue Box system for beverage container recovery, 1992.

BC Ministry of Environment, Lands & Parks:- Assisted and advised Gary Holman in his report on the methodology for estimating the economic impacts of BC Lands' Sales and Tenure Program, 1996.

BC Ministry of Forests, Old Growth Values Team of the British Columbia Old Growth Strategy Project:- Prepared a report "Socio-Economic Evaluation of Old Growth Conservation Strategies - Demonstration of a Multiple Account Approach", May, 1991.

Canadian Council of Ministers of the Environment:- With Dillon Consulting Limited prepared a study to develop and apply an evaluation methodology identifying benefits of specific environmental programs, June, 1997.

Canadian Centre for Policy Alternatives:- Prepared a multiple account benefit-cost evaluation of the Vancouver-Whistler 2010 Olympic and Paralympic Games, 2003.

City of Surrey:- Reviewed the evaluation process used in the selection of a private partner in a Water Metering Incentive Program, 2000.

CUPE:- Reviewed Partnership BC's report outlining its methodology for assessing the value for money of P3 contracts versus traditional public sector procurement of major, 2009.

Friends of Nemaiah Valley:- Prepared a report on the social benefits and costs of the proposed Prosperity mine project, 2009.

Gitxsan Tribal Council:- Prepared a report on the social benefits and costs of the proposed Kemess North Mine extension projects, 2006.

Golder Associates:- Prepared a report "Socio-Economic Assessment of Saskatchewan Wheat Pool/Cargill's Proposed Grain Terminal at Roberts Bank", 1996.

Greater Vancouver Regional District:- Provided advice on the implementation of the financial component of the comprehensive transfer station, hauling and waste disposal agreement with Wastech Services, 2003-2005.

____:- Assisted in the negotiation of a comprehensive transfer station, hauling and waste disposal agreement with Wastech Services 1997.

Greystone Properties Ltd.:- Conducted a multiple account evaluation of its proposal for a new trade and convention facility in Vancouver, 1997.

Human Early Learning Project (HELP):- Developed a multiple account framework for the evaluation of HELP's comprehensive set of proposals to reduce the number of at-risk children in British Columbia., 2010.

Indian and Northern Affairs Canada:- Provided advice on the multiple account benefit-cost analysis of alternative provisions for post-Treaty Own Source Revenues and other issues arising from Treaty negotiations, 2005- 2008.

Miramar Mining:- Reviewed a contingent valuation study to establish the value of a lake proposed to be used in a mining operation, 2004.

Montenay Inc:- Assisted in the valuation of the lifecycle unit costs of waste-to-energy management of municipal wastes and advised on related matters for Montenay's Expression of Interest to develop a new waste-to-energy facility in Greater Vancouver, 2006.

Nisga'a Tribal Council:- Developed guidelines for the assessment of the social economic and cultural impacts of major projects on Nisga'a lands, in accordance with provision 8f of the Nisga'a Treaty and assisted with the application of those guidelines to two proposed mine projects, 2010-2012.

Partnerships BC:- Prepared a report on the appropriate tipping fee for the use of Crown land for Britannia mine waste treatment sludge disposal, 2004.

____:- With Robin Hanvelt Consultants, prepared a report on the distributional implications of the relocation of St Paul's hospital and Mount St Joseph's hospital to a new centralized facility, 2004.

Tech BC:- Conducted a multiple account evaluation, including consideration of financial, university and local development impacts, of alternative facility development strategies, 1999.

YWCA:- Prepared a report on the methodology and findings in existing studies of the benefits and costs of high quality childcare, 2005.

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis.

QUESTION:

Please identify all regulators who have adopted Dr. Shaffer's multi-account benefit approach.

RESPONSE:

Dr. Shaffer is not aware of regulatory agencies that have adopted multiple account benefit-cost guidelines, but guidelines based on similar principles were developed and applied by the British Columbia government as part of its oversight of Crown Corporation investments, and the federal Treasury Board Secretariat's guidelines for the cost-benefit analysis of regulatory proposals (please see Manitoba Hydro's response to CAC/MH I-152 (b)) are based on similar principles, particularly with the stakeholder analysis called for in those guidelines.

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.1.2; Page No.: 5

QUESTION:

Apart from the use of a 6% real discount rate, is there any difference between the analysis undertaken for purposes of Market Valuation and that described in Chapter 9, Sections 9.1 through 9.3? If so, please explain what the differences are.

RESPONSE:

There is no material difference except for the discount rate. The market valuation account is defined as the net revenues or costs of the development plans from the point of view of Manitoba Hydro and its project partners.

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.3.2; Page No.: 25

PREAMBLE: In Manitoba Hydro's recent Bipole III Submission to the CEC concerns were raised about the load serving capability of Manitoba Hydro's system without Bipole I&II.

QUESTION:

Please provide a series of graphics that show the peak load forecasts prepared in both 2012 and 2013 and also sets out, for each development plan, the forecast load serving capability of Manitoba Hydro without Bipole I & II but assuming Bipole III is in-service as proposed. Please include in the peak load forecast (showing separately) any export contracts that must be met even in the event of a failure of Bipoles I& II.

RESPONSE:

The answer sought by the question is under a deterministic assumption that Bipoles I and II are out of service. The scenario of Bipole III only is not a probable normal operating condition and under this situation, a new series of operating procedures would need to be simulated for a valid study. The load carrying capability of Manitoba Hydro's system without Bipole I & II but with Bipole III is not calculated by the reliability models; instead the simultaneous loss of Bipoles I and II is one of the contingencies considered in the Monte Carlo simulation of the system. Thus the LOLE study in the appendices already probabilistically considers Manitoba Hydro's system without Bipole I&II.

No LOLE/LCC model runs have been undertaken with Bipole III and without Bipoles I & II. Nonetheless, in an attempt to provide the essence of the information sought by the question, if the model were restructured to calculate the load carrying capability without Bipoles I and II but with Bipole III, the load carrying capability would be greatly less than that submitted in the

NFAT submission; it is judged that the load carrying capability would be less than the peak loads even without any export loads.

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.3.2; Page No.: 25

PREAMBLE: In Manitoba Hydro's recent Bipole III Submission to the CEC concerns were raised about the load serving capability of Manitoba Hydro's system without Bipole I&II.

QUESTION:

Please provide a series of graphics that show the peak load forecasts prepared in 2012 and 2013 and also sets out, for each development plan, the load serving capability of Manitoba Hydro without Bipole III but assuming Bipole I & II are in-service. Please include in the peak load forecast (showing separately) any export contracts that must be met even in the event of a failure of Bipole III.

RESPONSE:

The load carrying capability of Manitoba Hydro's system without Bipole III but with Bipoles I and II is not calculated by the reliability models; instead the loss of Bipoles III is one of the contingencies considered in the Monte Carlo simulation of the system. In an attempt to provide the essence of the information sought by the question, if the model were restructured to calculate the load carrying capability without Bipole III but with Bipoles I and II, the load carrying capability would be less than those values reported in the Appendix 13.1 of Manitoba Hydro's NFAT Business Case Submission.

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.3.2; Page No.: 24

QUESTION:

Why is cumulative rate increase the appropriate measure of customer rate impact? Why wouldn't a better measure be the total amount paid by customers for electricity under each development plan?

RESPONSE:

The cumulative rate changes measure the relationship of projected rates to current rates. This measure is well understood and has been commonly used in regulatory proceedings.

In evaluating customer rate impacts, the absolute total amount paid by customers is not as useful as cumulative rate changes. Both types of measures are readily available in the pro forma financial statements, and in addition, analysis of consumers' revenue on a present value basis can be found in the response to PUB/MH I-149a.

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.3.2; Page No.: 25

QUESTION:

Please compare the four development plans using the cumulative NPV of Additional General Consumers Revenues as the measure of rate impact for each plan.

RESPONSE:

Please see the response to PUB/MH I-149(a).

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.3.2; Page No.: 10

PREAMBLE: The Manitoba Economy Account estimates the potential incremental income earned by Manitobans under each Plan.

QUESTION:

Why doesn't the Manitoba Economy Account also consider the impact on the Manitoba Economy of the difference in electricity bills that occur under each of the Plans, since the dollars spent on electricity are not available to spend/invest elsewhere in the economy?

RESPONSE:

Benefit-cost analysis is not economic impact analysis. It focuses on incremental net gains or losses. Consequently for the Manitoba economy the multiple account benefit-cost analysis focuses on direct impacts of the project where there is reason to believe there may be net gains or losses for the affected workers. It doesn’t address indirect and induced impacts from project expenditures nor spending impacts related to electricity price increases because it is not clear what, if any, incremental income consequences those impacts would have.

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.3.6; Page No.: 59

QUESTION:

Please identify the communities where the members of the four KCNs are located.

RESPONSE:

KCN members live in a number of communities, some on and some off reserve. The following are the communities with the largest number of members:

44) Tataskweyak Cree Nation: Split Lake.

45) War Lake First Nation: Ilford.

46) York Factory First Nation: York Landing.

47) Fox Lake Cree Nation: Bird and Gillam.

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.3.6; Page No.: 59

QUESTION:

What are total number of residential electricity customers currently in these communities?

RESPONSE:

As of September 2013, the number of residential electricity customers in each community is:

Tataskweyak - 376

War Lake - 34

York Factory - 125

Fox Lake - 50

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.3.6; Page No.: 59

QUESTION:

What is the average annual electricity use by residential electricity customers currently in these communities?

RESPONSE:

As of September 2013, the average annual electricity use by residential customers in each of the following communities is:

Tataskweyak - 40,113 kWh
War Lake - 28,724 kWh
York Factory - 33,390 kWh
Fox Lake - 29,368 kWh

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.3.6; Page No.: 59

QUESTION:

What is the average use for the 10% of residential accounts in these communities with the highest annual consumption?

RESPONSE:

As of September 2013, the average annual use for the 10% of residential accounts with the highest consumption in the following communities is as follows:

Tataskweyak - 61,742 kWh
War Lake - 45,495 kWh
York Factory - 60,738 kWh
Fox Lake - 45,525 kWh

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.3.6; Page No.: 59

QUESTION:

What is the current total electricity usage in these communities?

RESPONSE:

As of September 2013, the total annual electricity usage for the residential and commercial accounts in each community is as follows:

Tataskweyak - 21,184,362 kWh
War Lake - 3,064,581 kWh
York Factory - 6,859,883 kWh
Fox Lake - 3,704,746 kWh

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.3.6; Page No.: 57

QUESTION:

Please discuss the extent to which the various Plans have disproportional impacts on: a) urban vs. rural Manitobans and b) low vs. high income Manitobans.

RESPONSE:

It is not anticipated that there would be disproportional net benefits or costs for rural versus urban or low versus high income Manitobans, though there would be disproportionate effects for certain groups as noted in chapter 13 (e.g., net benefits for project partners; net costs for individuals not satisfied with right of way or other impact compensation).

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.3.7; Page No.: 66

QUESTION:

Please provide a revised version of Table 13.9 where the Customer Account effects are monetized based on the difference (from the Preferred Plan) in the Additional General Consumers Revenue net present valued using a 6% real discount rate.

RESPONSE:

The purpose of the customer account is to highlight the distributional implications between ratepayers in the short to medium versus long term. It would be incorrect to calculate the present value of the customer rate impact and add it to the other monetized accounts because it would overlap with what is already reflected in the market valuation account, Further, it would be inappropriate to discount the customer account at a 6% rate because that significantly overstates estimates of social time preference, the relevant rate to use for weighting present and future rate impacts given that the cost of capital is already reflected in the calculation of revenue requirements and rates.

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.3.8; Page No.: 69

QUESTION:

Please confirm that Manitoba Hydro Net Revenue S-Curves shown on page 69 are the same curves as the NPV S-curves presented in Chapter 10, Section 10.1.4.2. If not, what are the differences?

RESPONSE:

Confirmed.

The s-curves shown in Section 10.1.4.2 of Chapter 10 are the same as those shown on page 69 of Chapter 13.

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.3.8; Page No.: 69

QUESTION:

Please confirm that with a 66.67% Manitoba Hydro investment in the US portion of the 750 MW line, the K19/C25/750 MW curve would shift to the left.

RESPONSE:

As stated in Chapter 8 of the NFAT Business Case, for the purposes of NFAT evaluation, while Manitoba Hydro will not enter into an arrangement in which it owns more than 49% of the proposed U.S. interconnection, a conservative assumption has been used whereby Manitoba Hydro will be responsible for approximately two-thirds of the combined capital and ongoing operating costs associated with the U.S. portion of the 750 MW interconnection facilities.

Based on the above assumption, it is confirmed that the s-curve would shift to the left.

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.3.8; Page No.: 69

QUESTION:

If possible, please re-do Figure 13-3 (should labeled Figure 3-11) based on a 66.67% investment by Manitoba Hydro.

RESPONSE:

Manitoba Hydro is interpreting this information request to ask for Figure 13.3 of Chapter 13 to be redone based on a 66.67% investment by Manitoba Hydro.

As stated in Chapter 8 of the NFAT Business Case, for the purposes of NFAT evaluation, while Manitoba Hydro will not enter into an arrangement in which it owns more than 49% of the proposed U.S. interconnection, a conservative assumption has been used whereby Manitoba Hydro will be responsible for approximately two-thirds of the combined capital and ongoing operating costs associated with the U.S. portion of the 750 MW interconnection facilities.

Figure 13.3-1 below provides the s-curves as provided in Figure 13.3 on page 69 of Chapter 13. The Preferred Development Plan (Plan 14 – K19/C25/750MW (WPS Sale & Investment)) assumes Manitoba Hydro is responsible for approximately 40% of the capital costs and ongoing operating costs associated with the U.S. portion of the 750 MW U.S. interconnection facilities.

Figure 13.3-2 below re-plots the s-curves from Figure 13.3-1 to show an s-curve for an adjusted Plan 14 where Manitoba Hydro is responsible for approximately two thirds of combined capital costs and ongoing operating costs associated with the U.S. portion of the 750 MW U.S. interconnection facilities.

Figure 13.3-1: S-Curves as shown in Figure 13.3, Chapter 13

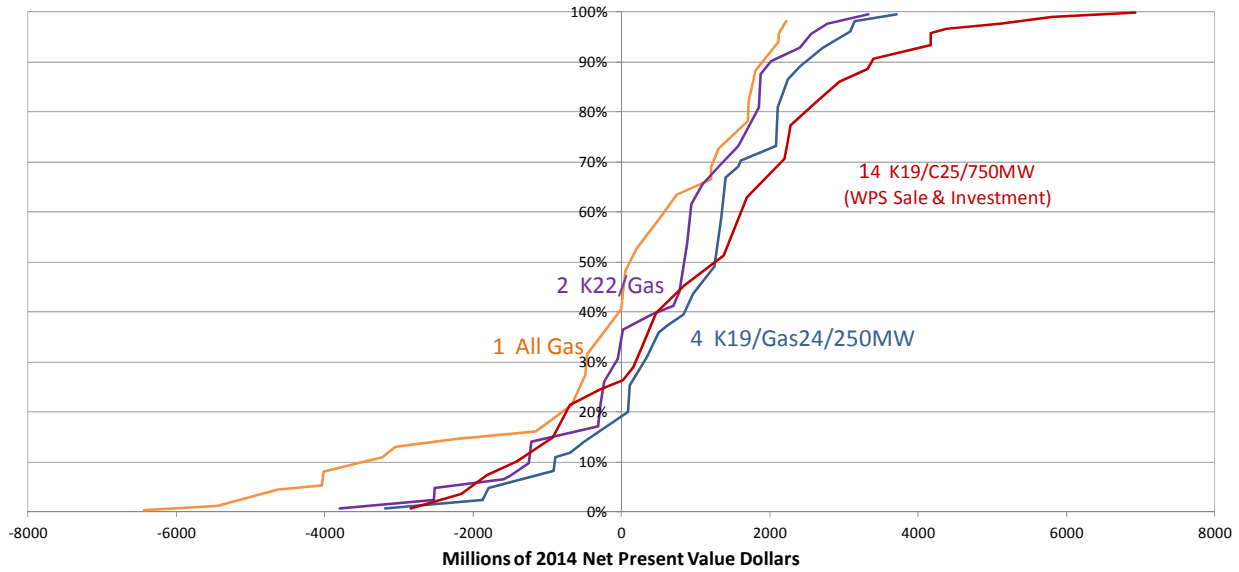
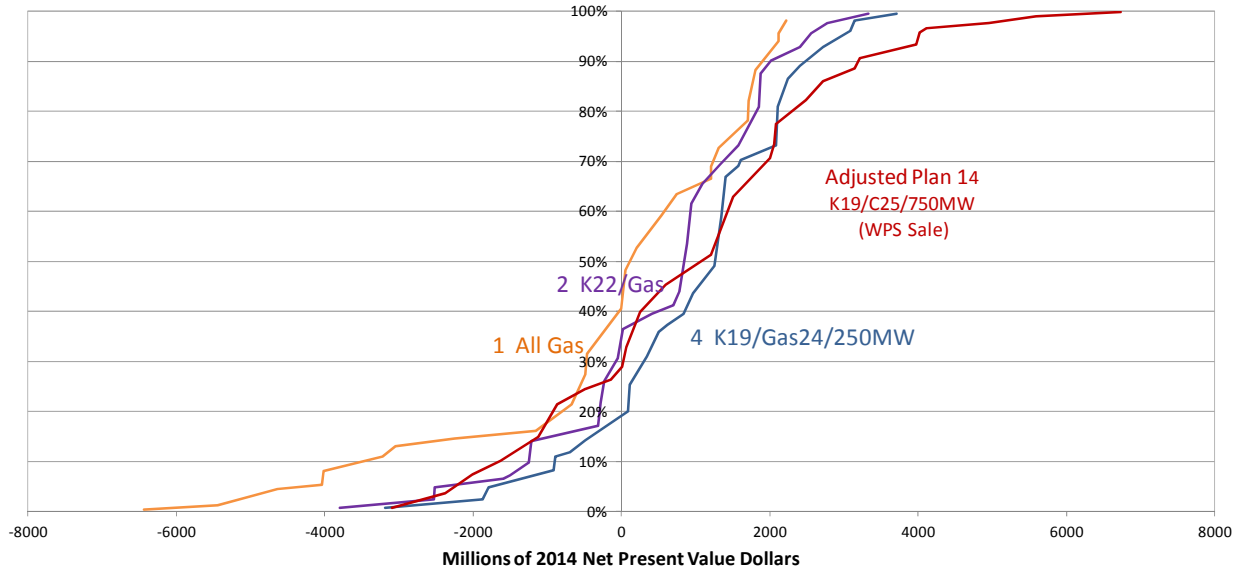


Figure 13.3-2



REFERENCE: Chapter 14: Conclusions; Section: 14.7; Page No.: 49

QUESTION:

What are the potential implications for both the cost and timing of Keeyask if Lake Sturgeon on the Nelson River are listed under the SARA? In particular, could cost increases and/or in-service delays negate the positive conclusions regarding Pathway 3 (relative to Pathway's 1 and 2) found at Chapter 14, page 43 (lines 4-8)?

RESPONSE:

Manitoba Hydro has been working extensively with the DFO during the Keeyask environmental licensing process to understand what the requirements will be for fish protection, compensation and passage overall and for Lake Sturgeon in particular. DFO has indicated that it is giving particular consideration to Lake Sturgeon, given the COSEWIC assessment from 2006, and are requiring strict protection standards for the species consistent with what could be required if it were listed. Manitoba Hydro's mitigation measures for Keeyask effects to Lake Sturgeon are designed to satisfy those strict requirements. If Lake Sturgeon were to be listed as endangered Manitoba Hydro would apply for permits to construct and operate the Project. Given the precautionary approach of the DFO on Lake Sturgeon protection, which would be incorporated into the conditions of a *Fisheries Act* authorization for the Project that Manitoba Hydro would be required to satisfy, it is expected that any cost and timing delays that could result from a potential Lake Sturgeon listing and permitting requirements would not be sufficient to negate the positive conclusions regarding Pathways 3, 4 or 5. Please refer to the response to CAC/MH I-231b for additional relevant information.

REFERENCE: Chapter 14: Conclusions; Section: 14.7; Page No.: 49

QUESTION:

Would a decision to list Lake Sturgeon on the Nelson River under the SARA have any impact on the Conawapa project?

RESPONSE:

A decision to list Lake Sturgeon on the Nelson River under the *SARA* would require strict protection and mitigation measures for Lake Sturgeon for Conawapa. Manitoba Hydro expects that, as with the Keeyask Project, DFO will give particular consideration to Lake Sturgeon during the environmental assessment and licensing process and require strict protection standards for the species consistent with what could be required if it were listed. Manitoba Hydro's mitigation measures for Conawapa effects to Lake Sturgeon will be designed to satisfy those strict requirements. Given the precautionary approach of the DFO on Lake Sturgeon protection, which would be incorporated into the conditions of a *Fisheries Act* authorization for the Project that Manitoba Hydro would be required to satisfy, it is expected that any cost and timing delays that could result from a potential Lake Sturgeon listing and permitting requirements would not be sufficient to negate the positive conclusions regarding Pathways 3, 4 or 5.

Alternatively, if a decision to list has been made by the time the Conawapa environmental licensing process is underway, the *SARA* requirements would be known and Manitoba Hydro would apply for permits to construct and operate the Project.

In both cases, Conawapa will have the benefit of lessons learned during the Keeyask environmental assessment and licensing process, as well as the results of early monitoring results from the Keeyask project, which would assist in identifying measures to meet *SARA* requirements, should Lake Sturgeon be listed.

Lastly, the optionality built into the Preferred Development Plan allows a decision on Conawapa as late as 2018 for a 2026 in-service date, by which time more information on progress in the *SARA* listing process will be available.

Please refer to the response to CAC/MH I-231b for additional relevant information.

REFERENCE: Chapter 14: Conclusions; Section: 14.7; Page No.: 49

QUESTION:

Would a decision to list Lake Sturgeon on the Nelson River under the SARA have any impact on the Conawapa project?

RESPONSE:

A decision to list Lake Sturgeon on the Nelson River under the *SARA* would require strict protection and mitigation measures for Lake Sturgeon for Conawapa. Manitoba Hydro expects that, as with the Keeyask Project, DFO will give particular consideration to Lake Sturgeon during the environmental assessment and licensing process and require strict protection standards for the species consistent with what could be required if it were listed. Manitoba Hydro's mitigation measures for Conawapa effects to Lake Sturgeon will be designed to satisfy those strict requirements. Given the precautionary approach of the DFO on Lake Sturgeon protection, which would be incorporated into the conditions of a *Fisheries Act* authorization for the Project that Manitoba Hydro would be required to satisfy, it is expected that any cost and timing delays that could result from a potential Lake Sturgeon listing and permitting requirements would be nominal.

Alternatively, if a decision to list has been made by the time the Conawapa environmental licensing process is underway, the *SARA* requirements would be known and Manitoba Hydro would apply for permits to construct and operate the Project.

In both cases, Conawapa will have the benefit of lessons learned during the Keeyask environmental assessment and licensing process, as well as the results of early monitoring results from the Keeyask project, which would assist in identifying measures to meet *SARA* requirements, should Lake Sturgeon be listed.

Lastly, the optionality built into the Preferred Development Plan allows a decision on Conawapa as late as 2018 for a 2026 in-service date, by which time more information on progress in the *SARA* listing process will be available.

Please refer to the response to CAC/MH I-231b for additional relevant information.

REFERENCE: Chapter 14: Conclusions; Section: 14.3; Page No.: 19

QUESTION:

Please revise Table 14.8 so as to include for each pathway: a) the debt/equity ratio as at 2061/62 and b) the cumulative NPV of "Additional General Consumers Revenue" as of 2031/32 and 2061/62.

RESPONSE:

Please see the response to PUB/MH I-149(a).

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 44

PREAMBLE: Manitoba Hydro states that: "To evaluate the potential for variation, historic load variability has been analyzed using a probabilistic-based approach. Variations in annual weather adjusted load that have occurred in the past are used to estimate future variation. Doing this provides an estimate of the magnitude of the potential load variation from the forecast due to population, economy and other effects. 10% and 90% confidence bands (-/+ 1.28 standard deviations) were selected to be a proxy for the Low and High Load Forecast Scenarios for use in risk analysis studies."

QUESTION:

Please provide details on the calculation of the standard deviation of load.

RESPONSE:

Using the annual year-to-year changes in weather adjusted load, the standard deviation of the annual changes (SD) as well as the autocorrelation coefficient between changes (CORR) are calculated. The standard deviation for the years of the forecast is calculated as follows:

StdDev(1) = SD

StdDev(i) = (StdDev(i-1)^2 + SD^2 + 2*CORR*SD*StdDev(i-1))^0.5

REFERENCE: Appendix D 2013 Electric Load Forecast.

QUESTION:

Please indicate if factors other than weather have been considered in the estimation of the standard deviation of load.

RESPONSE:

Only the weather effect was removed prior to determining the standard deviation. Therefore, the standard deviation includes all effects except for weather.

REFERENCE: Executive Summary; Section: Executive summary; Page No.: 1

PREAMBLE: Hydro states that: "Manitoba Hydro, a Crown Corporation, is committed to maintaining reliable, affordable and environmentally sustainable energy for its customers, while ensuring long-term financial sustainability."

QUESTION:

Please indicate how Manitoba Hydro will determine that its energy is affordable.

RESPONSE:

Manitoba Hydro strives to provide affordable energy by being fiscally responsible in managing its overall business activities. As a benchmark, Manitoba Hydro monitors the electricity rates offered in Manitoba relative to other regions.

REFERENCE: Executive Summary.

PREAMBLE: Hydro states that:; "Manitoba Hydro, a Crown Corporation, is committed to maintaining reliable, affordable and environmentally sustainable energy for its customers, while ensuring long-term financial sustainability."

QUESTION:

Please indicate if this determination of affordability will by applied to low-income households in Manitoba.

RESPONSE:

Manitoba Hydro does not assess the affordability of energy based on income. In Manitoba, the responsibility for social programs addressing basic needs (e.g. food, shelter, etc) is the responsibility of governments and specific departments.

REFERENCE: Executive Summary; Page No.: 2

PREAMBLE: Hydro states that: "A final decision on construction of Conawapa for an ISD of 2026 must be made by 2018."

QUESTION:

Please explain why there is a difference between the construction period of 10 years (Executive Summary, p.5) and the final decision time to completion of 8 years.

RESPONSE:

The Conawapa Generating Station consists of ten generating units. The earliest first unit in-service date of 2026 assumes licensing is complete by November 2017, a construction commitment decision is made early 2018 and a first unit in-service date of May 2026; approximately 8 to 8 1/2 years after the start of construction. The difference of two years "between the construction period of ten years and the final decision time to completion of 8 years" is the completion of the nine additional units, which takes an additional two years with the last unit in-service in April 2028.

REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates; Page No.: 9

PREAMBLE: Manitoba Hydro states that: "The resulting contingency is output as a range of amounts for different desired levels of confidence in achieving budget under-run. This range is represented by what is known as the contingency curve. Along this curve a larger contingency amount means a higher level of confidence in under-running the budget. Hence, contingency for a 70% confidence level or P70 estimate will be greater than the contingency for a 50% confidence level or P50 estimate. Manitoba Hydro's corporate standard is to set contingency at a P50 or 50% confidence level."

QUESTION:

Please explain the rationale for choosing to set contingency at a P50 standard.

RESPONSE:

Applying contingency to the Base Estimate at P50 provides what is considered the most likely Base Estimate amount. Statistically, a base estimate with the P50 contingency has the highest likelihood (or frequency) of occurrence compared to other amounts. A contingency amount less than P50 would result in a more overly optimistic Base Estimate, whereas a contingency amount greater than P50 would result in a more conservative Base Estimate.

Recognizing that the P50 value has an equal chance of underrun or overrun, both scenario analysis and management reserves are examined to determine the recommended project budget.

Major risk items identified that are not covered in the P50 contingency are addressed through Management Reserve funds, as is the case in the Keeyask and Conawapa Generating Station capital cost estimates.

REFERENCE: Appendix 2.4 Developing the Keeyask and Conawapa Capital Cost Estimates.

QUESTION:

Please explain why alternative standards, such as P75 or P90, could not also be presented from the contingency curves to assess the capital cost risk.

RESPONSE:

Alternative capital cost amounts are considered within the plan analysis presented in the NFAT submission. The economic and financial analysis considers Base Estimate capital costs ranging between low and high cases. This provides for a full spectrum of base capital cost scenarios. Scenarios such as P75 fall within this spectrum. As such, other specific capital cost scenarios do not require additional analysis.

REFERENCE: Chapter 4: The Need for New Resources;; Page No.: 6

PREAMBLE: Hydro states that: "Manitoba's domestic energy consumption has grown, on average, at an annual growth rate of 1.7% or 371 GWh over the past 10 years. This growth trend is forecast to continue for the next 20 years at an average annual growth rate of 1.6% or 453 GWh. On an annual-average basis, forecast load growth is consistent with the average annual historical growth trend."

QUESTION:

Would Hydro agree that Manitoba energy consumption growth has been flat (close to 0%) during the most recent period between 2007 and 2012?

RESPONSE:

The weather adjusted Manitoba energy consumption in 2007/08 was 23,934 GW.h. The 2012/13 consumption was 24,404 GW.h, or a growth of 0.4% per year.

However, energy consumption was down primarily in General Service Top Consumers due to the effects of the economic downturn and the loss of one customer. Even with the economic downturn during this period, the other sectors did not see zero growth but had closer to normal growth rates, with Residential Basic growing from 6,624 GW.h in 2007/08 to 7,219 GW.h in 2012/13 at a annual growth rate of 1.7%, and General Service Mass Market growing from 7,967 GW.h in 2007/08 to 8,406 GW.h in 2012/13 at an annual growth rate of 1.1%.

REFERENCE: Chapter 4: The Need for New Resources

QUESTION:

Would Hydro agree that the forecast energy consumption growth of 1.6% reflects the growth pattern prior to 2007 rather than the growth pattern from 2007 to 2012?

RESPONSE:

The forecast energy consumption growth reflects expected population growth, energy use changes, and economic conditions in the future. Each sector is analyzed individually and then combined to produce the overall forecast.

The forecast only reflects past growth through the determination of the relationships between population growth, growth of the economy and energy growth. For those relationships, the growth of the past 20 years is used so that it will include both periods of lower growth and periods of higher growth.

REFERENCE: Executive Summary; Page No.: 30

PREAMBLE: Manitoba Hydro states that: "Rate increases are required for all evaluated alternatives. The financial evaluation shows that higher rates are required in the medium term under all of the development plans, regardless of whether the plan is gas-based or hydro-based. New energy supply cannot be provided at the same current low rates that Manitoba Hydro customers have enjoyed over the last two decades."

QUESTION:

Would Manitoba Hydro agree that, in view of inflation forecasts of about 2% for the future, projected rate increases from 2014 to 2032 will exceed inflation by about 2% for the Preferred Development Plan (Pathway 5)?

RESPONSE:

Under the reference scenario for the period of 2014 to 2032, projected rate increases for all development plans are about 1.5% to 2.0% greater than Canadian CPI.

REFERENCE: Executive Summary

QUESTION:

Please provide forecasts from 2014 to 2032 for the growth in the real incomes of residential customers (i.e. growth in real wages and salaries) in Manitoba.

RESPONSE:

Manitoba Hydro does not have the requested information. Real incomes of residential customers in Manitoba are not projected as a part of Manitoba Hydro's annual Economic Outlook.

REFERENCE: Executive Summary; Page No.: 9

PREAMBLE: Manitoba Hydro states that: "Fuel pricing is one of the most important considerations driving electrical resource decisions and regional market prices for electricity. Recent reductions in cost due to developments in shale gas extraction have increased the attractiveness of natural gas as a supply source, particularly in relation to coal."

QUESTION:

Would Manitoba Hydro agree that higher prices discourage energy consumption for all users of energy, including hydroelectricity customers?

RESPONSE:

In accordance with economic theory, customers would increase usage in response to a reduction in price and reduce usage in response to an increase in price. While higher electricity prices may cause a reduction in electricity consumption, the extent of this reduction would depend on the level of price elasticity in the specific jurisdiction.

REFERENCE: Volume: Chapter 4: The Need for New Resources; Section: Chapter 4; Page No.: 12

PREAMBLE: Hydro states that: "The 1.2% annual increase in Residential Basic customers due to population growth combined with the 0.4% annual increase in average electricity use results in an annual growth rate of 1.6% for the Residential Basic sector over the next 20 years."

QUESTION:

Please explain how this forecast has accounted for rising hydroelectricity prices for residential ratepayers over the next 20 years, as forecast by Manitoba Hydro Please explain how rising hydroelectricity prices for residential ratepayers over the next 20 years can be expected to affect energy consumption forecasts, compared to a forecast that ignores price increases. Please explain why the annual electricity consumption growth forecast for Manitoba (1.6%) exceeds the annual electricity consumption growth forecast for the U.S. (0.9%) despite similar population growth forecasts in Manitoba and the U.S. and higher GDP growth forecasts for the U.S. compared to Manitoba.

RESPONSE:

Energy price elasticity is not a variable that is explicitly incorporated into Manitoba Hydro's load forecast. Please see Manitoba Hydro's response to PUB/MH I-256 and CAC/MH I-170.

Page 8 of the NFAT Executive Summary stated: "the U.S. Energy Information Administration's Annual Energy Outlook 2013 (AEO13) reference case projects overall U.S. load growth of 28% between 2011 and 2040 (0.9% per year)." This growth information was included to illustrate that the United States electricity load is growing overall despite their recession and planned DSM initiatives.

Manitoba Hydro forecasts a 1.6% growth rate in the 2012 Load Forecast. The AEO13 was produced in April 2013 and would more appropriately compare with the 2013 Load Forecast and its 20 year growth rate of 1.5%.

The AEO13 forecast includes all DSM initiatives. Adjusting Manitoba Hydro's Load Forecast for DSM programming would reduce the 20 year growth rate to 1.4%.

The AEO13 is an average for the United States. As well, the AEO13 admits its forecast is conservative. It compares the AEO13 forecast with the forecast of 3 other agencies, and the other agencies all forecast electricity sales to have a higher growth rate. National Renewable Energy Laboratory's forecast is 0.2% per year higher, Energy Ventures Analysis' forecast is 0.4% per year higher, and IHS Global Insight's forecast is 0.7% per year higher. This would indicate that the other three agencies are forecasting U.S. electricity growth rates to be between 1.1% and 1.6% per year. Manitoba Hydro's rate of 1.4% is within these bounds.

The report does not give specific details regarding the assumptions that led to the sectoral forecasts provided. However, it should be noted that AEO13 forecasts U.S. population to grow from 2011 to 2040 at 0.9% per year. Manitoba Hydro's 2013 Economic Outlook expects Manitoba's population to grow at a faster rate of 1.1% per year between 2011 and 2034. AEO13 gives real GDP growth at 2.5% compared to the 2013 Economic Outlook projecting 2.1% for Manitoba.

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 55

PREAMBLE: Manitoba Hydro states that: "The electricity price forecast is based on CPI and rate increase projections contained in the Integrated Financial Forecast. The real electricity price is forecast to increase by 1.7% in 2013/14, and then increase by 2.0% per year throughout the rest of the forecast period."

QUESTION:

Please indicate if Manitoba Hydro agrees that forecast real electricity price growth of 2% per year will reduce electricity consumption relative to a scenario in which real electricity prices grow at 0% per year.

RESPONSE:

Please see Manitoba Hydro's response to CAC/MH I-170.

REFERENCE: Appendix D 2013 Electric Load Forecast

PREAMBLE: Manitoba Hydro states that: "The electricity price forecast is based on CPI and rate increase projections contained in the Integrated Financial Forecast. The real electricity price is forecast to increase by 1.7% in 2013/14, and then increase by 2.0% per year throughout the rest of the forecast period."

QUESTION:

Please provide estimates of the impact on electricity consumption of forecast real electricity price growth of 2% per year compared to a scenario in which real electricity prices grow at 0% per year.

RESPONSE:

Specific price elasticities for the Manitoba load have not been determined. Please see Manitoba Hydro's response to CAC/MH I-170.

REFERENCE:

QUESTION:

Please indicate how the impact of real electricity price growth of 2% per year is reflected in the Manitoba load growth forecast.

RESPONSE:

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

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: Appendix 9.3; Page No.: 6-7

PREAMBLE: Hydro states that: "Table 1.3 demonstrates the derivation of Manitoba Hydro's weighted average cost of capital, both in nominal and real terms, for the rate used for the 2012 NFAT reference scenario economic evaluations. This results in a WACC of 7.05% in nominal terms and 5.05% in real terms. A long-term inflation rate of 1.9% is utilized to determine the WACC in real terms, i.e. without the effect of inflation."

QUESTION:

Please indicate whether Manitoba Hydro believes there are risks or uncertainties associated with the calculations in Table 1.3.

RESPONSE:

The calculations shown in Table 1.3 are for the reference case. Due to the uncertainty surrounding the macro-economic variables underlying these calculations, high and low cases were developed using the methodology outlined in Section 2.1.2 of Appendix 9.3.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation;

QUESTION:

Please itemize or, if possible, quantify any risks or uncertainties associated with the calculations in Table 1.3.

RESPONSE:

Please see response CAC/MH I-127, which defines the calculation of the low and high range for nominal and real weighted average cost of capital.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: Chapter 10; Page No.: 2-7

PREAMBLE: Hydro states that: "From an overall perspective, the Preferred Development Plan is most affected by the Energy Prices set of factors but still has significant exposure to the Discount Rate and Capital Cost sets of factors. The All Gas plan has exposure to the Discount Rate with narrow ranges of exposure to the Capital Cost and Energy Prices factors. For Plan 4 (K19/Gas24/250MW), because it has a mix of new gas and hydro resources, the impact of the three factors is moderated. The diversity provided by the mix of hydro-electric and natural gas-fired resources in the K19/Gas24/250MW development plan balances the effect of the factors and limits the significance of their effect on incremental NPV."

QUESTION:

Please indicate whether the impact of the discount rate is also significant for plans other than the All Gas and Preferred Development Plans.

RESPONSE:

The Discount Rate factor is considered to be one of the highest impact factors for all economic evaluations of development plans. Figure 10.2 in Chapter 10 provides the impact of Discount Rate in the K19/Gas24/250MW development plan (Plan 4) in addition to the All Gas and Preferred Development plans. In general terms, the Preferred Development Plan is more affected by discount rate due to the high upfront capital investment in two hydro plants. It would be expected that discount rate will have this effect on all of the development plans with two hydro plants. Where the plans have a mix of hydro development and natural gas developments, the impact of discount rate (as well as the other two factors) would be moderated.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: Chapter 10; Page No.: 18-19

PREAMBLE: Hydro states that: "For example, Plan 5 has a smaller box and shorter whiskers than the Preferred Development Plan (Plan 14): this indicates that the Preferred Development Plan has greater variability but has more upside potential."

QUESTION:

Would Hydro agree that greater variability is a measure of greater risk attached to the plan?

RESPONSE:

Manitoba Hydro does not agree that greater variability is a measure of greater risk attached to the plan. Risk is commonly used to connote downside uncertainty or variability. In this context, it is a bad thing, represents loss, and is something to be avoided. Greater variability does not necessarily correlate to greater (downside) risk. Greater variability could mean greater (upside) potential.

In the context of the referenced statement in the preamble, variability refers to the range of NPVs represented by the relative size of the box and whiskers. Per the statement above, this measure is not a direct representation of (downside) risk or loss. On the other hand, comparing the NPV between two development plans at a specified probability reflecting a worse or better than average outcome, such as P25 or P75 respectively, can demonstrate whether there is more or less risk between plans. For example, Plan 14 has a lower NPV at P25 than the corresponding NPV for Plan 5 at P25, indicating there is more risk in Plan 14 than Plan 5 at the P25 probability. That is, the downside associated with Plan 14 is worse than the downside risk associated with Plan 5. Similarly, comparing the probability associated with a specified NPV between two development plans also provides an indication of whether there is more or less risk between the plans. Plan 14 has a higher NPV at P75 than the corresponding NPV for Plan 5 at P75, indicating there is less risk in Plan 14 than Plan 5 at the P75 probability. That is, the

upside potential associated with Plan 14 is better than the upside potential associated with Plan 5. Similarly, comparing the probability associated with a specified NPV between two development plans also provides an indication of whether there is more or less risk between the plans. This type of comparison can be done more effectively using the cumulative probability curves as they provide more detailed information.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities

QUESTION:

Would Hydro agree that there is a trade-off between expected return to a plan and its risk, i.e. that plans with greater expected return may not be preferred because they involve greater risk?

RESPONSE:

Depending on the circumstances and the risk profiles of the plans in question, it could occur that plans with greater expected return may not be preferred due to their risk profile. Please also see Manitoba Hydro's response to CAC/MH I-176a.

In Manitoba Hydro's business case, from the economic perspective, careful consideration must be given to the trade-offs between plans due to the differences in the risk profiles between the plans. For example, long-life assets as opposed to assets, which in relative terms, have short lives, or large upfront capital investments and very low operating costs as opposed to smaller increments of investment over time and higher operating costs. Other perspectives beyond economics such as the financial and multiple account perspectives and considerations for optionality allow for a more fully informed business case.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Page No.: 26-27

PREAMBLE: Manitoba Hydro states that: "Below the 50th percentile, the risk profile is similar for the two plans but is driven by different factors. The downside risk of Plan 5 is due to a greater proportion of operating costs being related to thermal generation, particularly under low discount rate scenarios. As the Preferred Development Plan, which has Conawapa in 2025/26, has a large volume of surplus power, it is more sensitive to lower energy prices particularly when combined with higher discount rates and higher capital costs. Above the 50th percentile, the Preferred Development Plan lies to the right of Plan 5, reflecting significantly greater value primarily due to the availability of surplus power from the Conawapa G.S. at reference or higher energy prices."

QUESTION:

Would Manitoba Hydro agree that plans with S-curves such as Plan 5 in Fig. 10.14, which lie to the right of the S-curve for the Preferred Development Plan below P50 and to the left of the Preferred Development Plan above P50, unambiguously involve less risk?

RESPONSE:

Plan 5, as illustrated by Figure 10.14, does not "unambiguously" involve less risk than Plan 14. As stated in the preamble, "Below the 50th percentile, the risk profile is **similar** for the two plans but is driven by different factors." Below the 30th percentile, in particular, Plan 5 lies to the right of Plan 14, indicating that Plan 5 has less downside risk in this region of the graph however the curves merge so that the worst case scenario for both of these plans is essentially the same. At the 50th percentile values are essentially the same for both plans. "Above the 50th percentile, the Preferred Development Plan lies to the right of Plan 5, reflecting **significantly greater** value..." In this region, Plan 5 is not lower risk (better) and in fact is dominated by Plan 14.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Page No.: 30-31

PREAMBLE: Hydro states that: "When all five plans are considered together, there is a noticeable distinction in the upside potential (beyond the 70th percentile) for the plans with the Conawapa G.S. There is a smaller range across the five plans below the 40th percentile, with the plans with natural gas generation lying to the right of the other three plans, indicating less downside risk. Plan 12 (K19/C31/750MW) and the Preferred Development Plan are higher in expected value when compared to the other plans. On the basis of both the expected value and upside potential, the Preferred Development Plan is the most attractive plan with a "750 MW interconnection" plan. Plan 12 is a reasonably close second choice."

QUESTION:

Please explain why downside risk is not a factor, as well as expected value and upside potential, in selecting the "most attractive plan." Please explain why downside risk cannot be combined with upside potential to provide a summary measure of risk to select the "most attractive plan." Would Hydro agree that, in comparing plans, only a plan with an S-curve lying to the right at all points (at all percentiles) of the S-curve of another plan is unambiguously superior (i.e. involves no trade-off between expected return and risk)?

RESPONSE:

In comparing alternatives, Manitoba Hydro agrees that downside risk, upside opportunity and expected value should all be considered. S curves are particularly helpful for understanding and visualizing risk and opportunity. When evaluating alternatives based only on maximizing a single objective (such as NPV), an alternative with an S curve strictly to the right is clearly superior or dominant, irrespective of how much one values risk and opportunity. Choosing among alternatives whose S curves cross or overlap involves making tradeoffs; that is, one must explicitly consider the relative importance of downside risk, upside opportunity and return (expected value). Summary measures that combine downside risk and upside opportunity, such as standard deviation or 10-90 percentile ranges, are available. However, they can be

misleading when applied to asymmetric probability distributions - distributions whose downside risk and upside opportunity are considerably different. Consequently, they should be used only with great care, if at all, under such circumstances.

The observations on page 30-31 are with respect to the S curves in Figure 10.17. Alternatives with natural gas-fired generation have somewhat less downside risk; that is, they have better "worst case" outcomes and are less likely to lead to losses (vs. All Gas Ref Ref Ref). Alternatives 5, 6, 12 and 14 (Preferred Plan) are all relatively close with respect to downside risk. Alternatives with Conawapa have more upside opportunity; that is, they have better "best case" outcomes and are more likely to lead to gains (vs. All Gas Ref Ref Ref). Alternatives 12, 14 (Preferred Plan) and 15 are all relatively close with respect to upside opportunity. Among the five alternatives, the Preferred Plan has the best expected value, is close to the best in upside opportunity, and is only modestly worse than best in downside risk. On the basis of all three of these considerations, it appears to be the most attractive among these five development plans.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities; Section: Chapter 10; Page No.: 53

PREAMBLE: Hydro states that: "Table 10.14 also shows that under the low and high load sensitivities the economic ranking of the development plans studied does not change. The K22/Gas development plan continues to be more economic than the All Gas development plan, and the Preferred Development Plan continues to be the most economic of the three plans studied."

QUESTION:

Please indicate if the two plans involving gas development have more flexibility for expansion if load demand turns out to be greater than forecast (high load scenario).

RESPONSE:

The two plans involving gas development have less flexibility for expansion if load demand turns out to be greater than forecast (high load scenario). This is true for two reasons.

48) Natural gas generation (or other short lead time resource such as wind generation) can be as easily added to the other plans as it can be to the gas plans.

49) In the hydro plan (K19/C25/750MW) the 750MW interconnection would enhance the ability to arrange firm contracts for import of capacity and/or energy as required by the higher than forecast load growth. Such import contracts can be arranged with even a shorter lead time than for natural gas generation.

Furthermore, the K19/C25/750MW plan has more surplus power than the gas plans and thus would be in a better situation to accommodate higher load growth than the two gas plans.

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities

QUESTION:

Please indicate if the two plans involving gas development have more flexibility for contraction if load demand turns out to be smaller than forecast (low load scenario).

RESPONSE:

The two plans involving gas development have more flexibility for contraction if load demand turns out to be smaller than forecast (low load scenario).

REFERENCE: Chapter 10: Economic Uncertainty Analysis - Probabilistic Analysis and Sensitivities

QUESTION:

Please indicate if plan flexibility, such as altering the size of the development and its in-service dates, has been considered in comparing the All Gas and K22/Gas development plans to the Preferred Development Plan. If yes, please explain how it has been considered.

RESPONSE:

The load growth sensitivity analyses reported in Tables 10.13 and 10.14 did alter the ISDs of the natural gas generation in consideration of different load forecasts. Please refer to Table 10.12 and also Appendix 4.2. The analyses did not alter the ISDs of the hydro projects, either Keeyask or Conawapa. The ISD of Conawapa was not deferred in the low load growth sensitivity, however as discussed in Chapter 14, conditions will be continually monitored to determine if Conawapa should be constructed and for what ISD. This decision will be influenced by many factors including load growth. Low load growth projections prior to 2018 may result in the decision to delay the ISD of Conawapa.

Altering the size of the natural gas generation was not undertaken in these sensitivities because altering the ISDS was a reasonable means to respond to the differing load growth. Also, in the low load growth situation, assuming smaller sized natural gas plants would have tended to involve an overall increase in the per unit energy cost for gas generation. Altering the size of the hydro projects was not undertaken because the majority of hydro plant costs are fixed and installing less units in a dam and powerhouse would likely not be economic.

Please refer to the response to PUB/MH I-279 for a further discussion of optionality.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: Chapter 11; Page No.: 10

PREAMBLE: Hydro states that: "During this time frame, the even-annual rate increases for the Preferred Development Plan (green) are generally higher, in keeping with its higher upfront capital investment."

QUESTION:

Please indicate if the two development plans involving a Conawapa ISD of 2026 (green and purple plans 14 and 13) result in the highest rate increases from 2015 to 2032.

RESPONSE:

As indicated in Table 14.8 (Chapter 14, page 19), Plan 13 K19/C25/250 and the Preferred Development Plan 14 K19/C25/750 result in even-annual rate increases of 3.98% and 3.95% from 2014/15 to 2031/32 under the reference scenario, respectively. The other six development plans result in even-annual rate increases from 3.42% to 3.86% under the reference scenario.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans

QUESTION:

Please indicate if the two development plans involving Keeyask with gas development in place of Conawapa (light blue and brown plans 4 and 6) result in lower rate increases from 2015 to 2032 than all plans except the All Gas plan.

RESPONSE:

As indicated in Table 14.8 (Chapter 14, page 19), Plan 4 K19/Gas/250 and Plan 6 K19/Imp/Gas/750 result in even-annual rate increases of 3.42% and 3.50% from 2014/15 to 2031/32 under the reference scenario, respectively. Plan 1 All Gas results in even-annual rate increases of 3.43% under the reference scenario.

REFERENCE: Chapter 12: Economic Evaluations - 2013 Update On Selected Development Plans; Section: Chapter 12; Page No.: 14

PREAMBLE: Hydro states that: "As demonstrated in the fourth column of Table 12.5, the change in discount rate from 5.05% to 5.40% significantly decreases the NPVs for all development plans relative to the All Gas plan. The 0.35% increase in discount rate has a greater impact on development plans with higher levels of capital investment, with the Preferred Development Plan experiencing the largest relative decrease to NPV of $663 million ($2,125 million minus $1,462 million). The relative decreases in NPVs for the other development plans are: Plan 2: $232 million; Plan 4: $304 million; and Plan 12: $559 million."

QUESTION:

Please indicate if this modest change to the discount rate from 5.05% to 5.40% indicates that the plans involving Keeyask and Conawapa (plans 12 and 14) are more sensitive to the discount rate (and therefore interest rate) assumptions than the plans involving Keeyask followed by gas development (plans 2 and 4)

RESPONSE:

All development plans are sensitive to discount rates. The higher the discount rate, the less future events influence the current decision. Thus plans with a high upfront capital cost and benefits extending long into the future are affected more negatively by increases in discount rates than plans that have a lower upfront capital cost with greater operating costs and lower benefits and capital replacement costs extending out into the future.

As nominal interest rates are highly correlated with the rate of inflation, changes in interest rates would only have differential impacts on the various development plans to the extent that interest and inflation rates diverged and changed the real discount rate.

REFERENCE: Chapter 12: Economic Evaluations - 2013 Update On Selected Development Plans;

QUESTION:

Please indicate how historical data and Bank of Canada and other forecasts were used to update the discount rate projection from 5.05% to 5.40% between 2012 and 2013.

RESPONSE:

Please see the response to PUB/MH I-065 and PUB/MH I-156a.

REFERENCE: Chapter 12: Economic Evaluations - 2013 Update On Selected Development Plans; Page No.: 17

PREAMBLE: Hydro states that: "The 4.0 times DSM stress test has the effect of deferring the in-service date for Keeyask G.S. in Plan 2 by six years and defers the in-service date of the first natural gas-fired resource in Plan 4 by four years. Plan 14 in Table 12.10 is the Preferred Development Plan with fixed in-service dates for both Keeyask G.S. and Conawapa G.S. Plan 14a is a variant of the Preferred Development Plan in which the in-service date for Conawapa G.S. is deferred four years with 4.0 times DSM."

QUESTION:

Please indicate whether the impact of DSM sensitivity tests could also be realized by other reductions in load demand, such as might arise from consumer economies in response to higher electricity rates

RESPONSE:

Confirmed.

REFERENCE: Chapter 14: Conclusions; Section: Chapter 14; Page No.: 10

PREAMBLE: Hydro states that: "The third and fourth rows provide the 10th and 90th probabilistic measures of NPV from the analysis of the 27 scenarios. The 90th percentile (P90) indicates the upside benefit potential of the plans. The P90 upside benefit is the NPV benefit that occurs at the 90% probability level when considering the 27 scenarios; there is a 10% probability the benefits could be this high or higher. The P10 downside risk is the resulting NPV benefit that occurs at the 10% probability level when considering the 27 scenarios; there is a 10% probability the benefits could be this low or lower."

QUESTION:

Please indicate whether the spread between the P90 upside benefit and the P10 downside risk (i.e. the interdecile range) provides a measure of the variation in possible outcomes, or the risk, associated with each plan Please indicate how the interdecile range, or some other suitable measure of risk, compares to the expected value or return for each plan. That is, what is the nature of the trade-off between risk and expected return for the various plans?

RESPONSE:

The spread between the P90 upside benefit and the P10 downside risk (i.e. the interdecile range), along with the standard deviation, does provide a measure of the variation in possible outcomes, or the risk, associated with each plan. However, in this context, "risk" includes both the risk of having benefits lower than the expected value and having benefits higher than the expected value. Using this measure, an alternative with higher "risk" might in fact simply have higher upside rather than higher downside. A simple example can show how the interdecile range from P10 to P90 (or the standard deviation) can be misleading as a measure of downside risk. Consider two alternatives A and B with B strictly dominating A. That is, the S curve for B is strictly to the right of A. But B is "wider" or riskier. A could have an expected value of 1000 and a standard deviation or P10-90 interdecile range of 500. B could have an expected value of 1100 and a standard deviation or P10-90 interdecile range of 700. From the point of view of

expected value and standard deviation or P10-90 interdecile range, there appears to be a "risk-return tradeoff" here. It seems like a tough choice between expected value and risk. But that isn't actually true. B is strictly to the right of A, and no matter how one views the relative importance of downside risk and return, B is preferred. All the extra alternative B "risk" is on the upside. This example shows that using the P10-90 range of standard deviation to evaluate risk-return tradeoffs is inappropriate; it is really suited to symmetric distributions like normals.

Given this observation, a better measure of downside risk is actually the 10th percentile value. A lower value here indicates unambiguously that there is more downside risk. And a better way to approach the risk-return tradeoff issue is to look at the expected value and the 10th percentile downside value. This is the primary approach taken in describing the alternatives below.

Please refer to Section 10.1.4 for a generic discussion of the probabilistic analysis results and risk/reward. Section 10.1.4.2 and 10.1.5 discusses the probabilistic analysis including the trade-off between risk and expected return for the various plans utilizing the s-curves. Sections 14.2.1 to 14.2.6 provide a related discussion but not utilizing the s-curves.

With reference to Table 14.2, the discussion below will attempt to provide a summary of the trade-off between risk and expected return for the various plans.

Based on maximizing expected value, Plan 14 is preferred. It has the highest expected value. Based on minimizing downside risk (as measured by the 10th percentile outcome), Plan 5 is preferred. It has the highest 10th percentile value. With the exception of Plan 4, all the other plans are "dominated" by these two Plans; that is, they are worse than one or both of these alternatives on both expected value and downside risk. This includes:

Plan 1: worse than 5 and 14

Plan 7: worse than Plan 5

Plan 8: worse than Plan 5

Plan 2: worse than Plan 5

Plan 10: worse than Plan 5 and Plan 14

Plan 13: worse than Plan 5 and Plan 14

Plan 11: worse than Plan 5

Plan 6: worse than Plan 5

Plan 15: worse than Plan 5 and Plan 14

Plan 12: worse than Plan 14

Given these observations, there is really only a risk-return tradeoff among three alternatives: Plan 14, Plan 5 and Plan 4. All the other alternatives involve accepting inferior performance on both measures. Plan 14 is preferred if one is risk-neutral. Plan 5 is preferred if one is highly risk-averse. And Plan 4 is preferred given a particular balance of risk and return. However, as discussed in Section 14.6, the difference in downside risk between Plan14 and Plan 5 is reduced through the optionality of being able to defer or cancel Conawapa up to 2018 and thus shift from Plan 14 to Plan 5.

Plan 1, All Gas has the lowest Expected Value Benefit of the 15 plans, the lowest Upside Benefit and the largest Downside Risk. On a probabilistic basis, there is no overall tradeoff between risk and reward for Plan 1 relative to other plans; it is both low reward and high risk.

Both Plan 7 and Plan 8 have higher Expected Value Benefit than Plan 1 similar Upside Benefit but much lower Downside Risk. On a probabilistic basis, there is no overall tradeoff between risk and reward relative to Plan 1; they have both higher reward and lower risk. Relative to the plans with interconnections, Plans 7 & 8 have significantly lower Expected Value Benefit and

Upside Benefit. Their Downside Risks are variously lower, similar or higher than the interconnection plans.

Plan 10 compared to Plan 2 has significantly lower Expected Value Benefit but higher Upside Benefit and larger Downside Risk. Overall Plan 2 would be preferred to Plan 10 with no risk/reward tradeoff. Plan 2 has substantially less Expected Value Benefit and Upside Benefit without a commensurate reduction in risk relative to Plan 4.

Plan 4 has significantly higher Expected Value Benefit and a lower Downside Risk than plans 13, and 11. Of these Pathway 3, 250MW interconnection plans, Plan 4 would be preferred with no risk/reward tradeoff.

The comparison is more complicated when comparing the 250MW interconnection Pathway 3 plans (Plans 4,13 and 11) to the 750MW interconnection Pathway 4 plans (Plans 6, 15 and 12). Plan 4 has significantly higher Expected Value Benefit and lower Downside Risk than Plans 6, 15 and 12. On the other hand, Plan 4 has a lower Reference Scenario benefit and Upside Benefit than Plan 15 and a lower Upside Benefit than Plan 12. Considering only these factors Plan 4 would likely be preferred but there would be a tradeoff of reduced upside potential.

Furthermore, when comparing the 250MW Interconnection plans of Pathway 3 with the 750MW Interconnection plans of Pathway 4, consideration must be given to the real possibility of Conawapa being developed because of other export contract opportunities not considered in these evaluations (refer to Section 14.5). Should it be assumed that Conawapa would be developed because of these other opportunities, Pathway 4 is not of consideration and instead the Pathway 3 plans of 13 and 11 must also be compared to the Pathway 4 plans of 15 and 12, all of which include Conawapa. In such a comparison, the 750MW interconnection Plans 15 and 12 have slightly higher Expected Value Benefit and Reference Scenario benefit but with a

slightly larger Downside Risk. Considering this situation, 750MW Interconnection Plans 15 or 12 would likely be preferred to 750MW Interconnection Plans 13 and 11 but there would be a tradeoff of increased risk.

Plan 14 of Pathway 5 has the highest Expected Value Benefit and Reference Scenario benefit of any of the plans. However, Plan 4 of Pathway 3 has the second highest Expected Value Benefit with lower risk as measured by Downside Risk. Plans 14 would likely be preferred to Plan 4 but there would be a tradeoff of increased risk.

As concluded in Chapters 14, page 17:

> "The economic evaluations undertaken conclusively demonstrate that Pathways 3, 4 and 5 plans are clearly preferred to Pathways 1 and 2 plans. However, a clear and decisive preference between the 250 MW and 750 MW interconnection plans (Pathways 3, 4 and 5) cannot be established on the basis of only these evaluations, but must consider additional information. Such additional information would include:
>
> - qualitative consideration of factors not currently included in economic (and financial) evaluations, such as updates to interconnection capital costs, outcome of WPS negotiations and possible alternate or additional export agreements
> - financial and multiple accounts evaluations
> - flexibility and risks
> - reliability and energy security
> - environmental and socio-economic impacts and benefits."

Consideration also needs to be given to the risk reduction available through the optionality within the pathways as discussed in the submission, Section 14.6. Please also refer to Manitoba Hydro's response to Round 1, PUB-0279.

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 42

PREAMBLE: To determine low income rate impact CAC MB requires the following information.

QUESTION:

Please provide a schedule that sets out the Heating and Cooling Degree Days for Winnipeg, by month for Jan. 2000 to Dec. 2012. Please provide in both hard copy and accessible Excel spreadsheet formats.

RESPONSE:

Monthly Degree Days Heating History in Winnipeg (base 14'C)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2012	767.8	698.9	371.3	244.3	82.7	9.9	.0	.0	89.1	310.9	601.1	889.6	4,066
2011	1,031.2	788.9	698.8	286.8	110.3	12.9	.0	.0	60.8	204.0	481.2	683.6	4,359
2010	860.1	793.6	451.1	173.5	108.8	10.3	.0	9.0	79.9	188.7	520.6	878.1	4,074
2009	1,052.3	800.9	676.4	321.4	177.1	47.4	3.8	2.4	19.8	330.1	396.9	895.9	4,724
2008	962.2	933.1	696.6	319.8	180.9	21.3	.0	3.0	56.3	227.9	546.4	1,033.0	4,981
2007	931.0	919.6	592.5	296.6	82.7	15.5	.0	4.0	66.8	231.8	540.3	903.2	4,584
2006	662.6	841.1	624.1	150.3	105.2	3.5	.5	.0	70.3	330.7	556.9	734.3	4,080
2005	1,042.3	775.2	684.8	204.3	145.1	7.6	.0	.7	48.3	222.0	506.9	717.2	4,354
2004	1,106.8	745.3	616.8	311.8	207.9	36.7	5.4	32.0	36.5	253.0	446.3	882.9	4,681
2003	916.8	934.0	688.7	260.2	67.8	10.8	1.3	4.9	98.8	241.0	634.6	733.8	4,593
2002	886.5	671.1	795.2	362.9	210.4	11.5	.0	2.6	75.9	449.7	585.8	698.0	4,750
2001	825.0	905.0	625.0	278.5	74.9	19.5	2.9	5.4	52.9	300.9	392.7	758.8	4,242
2000	969.3	664.1	435.7	300.5	102.1	32.6	3.6	4.4	90.0	234.3	579.8	1,117.2	4,534

Monthly Degree Days Cooling History in Winnipeg (base 18'C)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2012	.0	.0	.5	.0	5.0	39.9	137.0	59.9	12.9	.0	.0	.0	255
2011	.0	.0	.0	.0	.5	32.0	109.0	78.5	19.0	10.6	.0	.0	250
2010	.0	.0	.0	.0	7.6	17.5	75.5	72.7	.0	.0	.0	.0	173
2009	.0	.0	.0	.0	.0	41.4	13.0	23.3	40.9	.0	.0	.0	119
2008	.0	.0	.0	.0	.0	15.8	36.7	68.2	2.7	.0	.0	.0	123
2007	.0	.0	.0	.0	6.2	32.2	110.8	37.3	12.4	.0	.0	.0	199
2006	.0	.0	.0	.6	10.5	40.6	120.0	65.1	16.6	.0	.0	.0	253
2005	.0	.0	.0	.0	3.6	40.6	92.1	39.6	21.7	.0	.0	.0	198
2004	.0	.0	.0	.0	.0	7.9	48.1	1.0	14.8	.0	.0	.0	72
2003	.0	.0	.0	.0	2.4	23.2	60.7	130.7	17.9	.0	.0	.0	235
2002	.0	.0	.0	.0	4.8	50.2	95.9	43.3	12.9	.0	.0	.0	207
2001	.0	.0	.0	1.7	2.8	29.7	92.6	72.2	12.1	.0	.0	.0	211
2000	.0	.0	.0	.0	.0	7.5	69.9	57.6	2.1	.0	.0	.0	137

The spreadsheet is provided as an attachment.

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 59

PREAMBLE: To determine low income rate impact CAC MB requires the following information.

QUESTION:

Based on the 2009 Residential Survey, what is the breakdown of total Residential customers as between: i) Single Family Dwellings; ii) Multi-Family Attached Dwellings and iii) Individually Metered Apartments for the province overall?

RESPONSE:

See Manitoba Hydro's response to CAC/MH I-186b.

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 59

PREAMBLE: To determine low income rate impact CAC MB requires the following information.

QUESTION:

For each housing type, what is the number of dwellings by heating type (i.e. Electric Heat Billed vs. Non-electric Heat Bills) for the province overall?

RESPONSE:

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

Dwelling Type	Electric Heat Billed	Non-Electric Heat Billed	Total
Single Detached	126,531	223,368	349,899
Multi-Attached	8,504	24,820	33,324
Apartment Suite*	19,908	35,965	55,873
Total Residential	154,943	284,153	439,096

*individually metered

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 59

PREAMBLE: To determine low income rate impact CAC MB requires the following information.

QUESTION:

Based on the 2009 Residential Survey, what is the breakdown of total Residential customers as between: i) Single Family Dwellings; ii) Multi-Family Attached Dwellings and iii) Individually Metered Apartments for the Winnipeg area?

RESPONSE:

Based on the 2009 Residential Survey, the breakdown of the total numbers of Residential dwelling types in the Winnipeg area are as follows:

Dwelling Type	**# of Customers**
Single Detached	163,033
Multi-Attached	26,579
Apartment Suite	46,481
Total Winnipeg	236,093

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 59

PREAMBLE: To determine low income rate impact CAC MB requires the following information.

QUESTION:

For each housing type, what is the number of dwellings by heating type (i.e. Electric Heat Billed vs. Non-electric Heat Bills) in the Winnipeg area?

RESPONSE:

Based on the 2009 Residential Survey, the breakdown of total numbers of Residential heating types by dwelling types in the Winnipeg area are as follows:

Dwelling Type	Electric Heat Billed	Non-Electric Heat Billed	Total
Single Detached	6,023	157,010	163,033
Multi-Attached	5,325	21,254	26,579
Apartment Suite	14,782	31,699	46,481
Total Winnipeg	26,130	209,963	236,093

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 59

PREAMBLE: To determine low income rate impact CAC MB requires the following information.

QUESTION:

What is the typical electricity use by month for an Electric Billed Customer in the Winnipeg area for each of the three housing types?

RESPONSE:

The following chart shows the typical electricity use (kilowatt hours) by month for an **Electric Billed Customer** in the Winnipeg area across each of the three housing types.

Month	Single Detached	Multi-Attached	Apartment Suite
January	4,279	2,812	1,463
February	3,328	2,065	1,072
March	3,096	1,939	1,019
April	2,431	1,502	794
May	1,493	843	471
June	1,169	746	409
July	1,056	537	399
August	848	588	413
September	1,067	518	439
October	1,430	919	551

November	1,950	985	563
December	2,774	1,589	859

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 59

PREAMBLE: To determine low income rate impact CAC MB requires the following information.

QUESTION:

What is the typical electricity use by month for a Non-Electric Billed Customer in the Winnipeg area for each of the three housing types?

RESPONSE:

The following chart shows the typical electricity use (kilowatt hours) by month for a **Non-Electric Billed Customer** in the Winnipeg area across each of the three housing types.

Month	Single Detached	Multi-Attached	Apartment Suite
January	1,190	861	353
February	984	754	314
March	921	661	306
April	885	705	299
May	731	513	280
June	795	612	284
July	861	646	319
August	824	645	344
September	858	672	325
October	827	644	307

November	785	585	283
December	886	677	298

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 59

PREAMBLE: To determine low income rate impact CAC MB requires the following information.

QUESTION:

Does Manitoba Hydro have any data as to the number of dwelling types or heating types for residential customers by income level?

RESPONSE:

Data as to the number of dwelling types or heating types for residential customers by income level is available based upon the 2009 residential survey. Please see Manitoba Hydro's response to CAC/MH I-189 (b).

REFERENCE: Volume: Appendix D 2013 Electric Load Forecast; Section: N/A; Page No.: 59

PREAMBLE: To determine low income rate impact CAC MB requires the following information.

QUESTION:

If yes, please provide the following for the Winnipeg area and for the total province: i) breakdown of Housing type by income; ii) breakdown of Heating type by Income; and iii) a breakdown of Housing/Heating type by income.

RESPONSE:

(i) Based on the 2009 Residential Survey, the breakdown of the total numbers of Residential dwelling types by annual household income for the Winnipeg area are as follows:

Income Range	Single Detached	Multi-Attached	Apartment Suite	Total
Under $25,000	16,924	3,497	12,876	33,298
$25,000-$49,999	39,361	7,975	16,883	63,219
$50,000-$74,999	38,075	8,726	10,906	57,707
$75,000-$99,999	29,092	3,788	4,099	36,979
$100,000 Plus	40,581	2,593	1,717	44,891
Total Winnipeg	163,033	26,579	46,481	236,093

Based on the 2009 Residential Survey, the breakdown of the total numbers of Residential dwelling types by annual household income for the Total Province are as follows:

Income Range	Single Detached	Multi-Attached	Apartment Suite	Total
Under $25,000	48,507	6,048	16,607	71,163
$25,000-$49,999	97,681	10,205	20,996	128,882
$50,000-$74,999	81,891	9,575	11,375	102,841
$75,000-$99,999	55,116	4,208	4,736	64,060
$100,000 Plus	66,704	3,287	2,159	72,150
Total Province	349,899	33,324	55,873	439,096

(ii) Based on the 2009 Residential Survey, the breakdown of the total numbers of Residential heating types by annual household income for the Winnipeg area are as follows:

Income Range	Electric Heat Billed	Non-Electric Heat Billed	Total
Under $25,000	4,747	28,551	33,298
$25,000-$49,999	8,080	55,139	63,219
$50,000-$74,999	7,725	49,982	57,707
$75,000-$99,999	3,609	33,370	36,979
$100,000 Plus	1,969	42,922	44,891
Total Winnipeg	26,130	209,963	236,093

Based on the 2009 Residential Survey, the breakdown of the total numbers of Residential heating types by annual household income for the Total Province are as follows:

Income Range	Electric Heat Billed	Non-Electric Heat Billed	Total
Under $25,000	30,715	40,448	71,163
$25,000-$49,999	49,721	79,161	128,882
$50,000-$74,999	36,657	66,184	102,841
$75,000-$99,999	19,881	44,179	64,060
$100,000 Plus	17,969	54,181	72,150
Total Province	154,943	284,153	439,096

(iii) Based on the 2009 Residential Survey, the breakdown of the total numbers of Residential **Electric Heat Billed** across dwelling types by annual household income for the Winnipeg area are as follows:

Income Range	Single Detached	Multi-Attached	Apartment Suite	Total
Under $25,000	646	547	3,554	4,747
$25,000-$49,999	1,830	1,844	4,406	8,080
$50,000-$74,999	1,361	1,532	4,832	7,725
$75,000-$99,999	1,005	1,183	1,421	3,609
$100,000 Plus	1,181	219	569	1,969
Total Winnipeg Electric Heat Billed	6,023	5,325	14,782	26,130

Based on the 2009 Residential Survey, the breakdown of the total numbers of Residential **Non-Electric Heat Billed** across dwelling types by annual household income for the Winnipeg area are as follows:

Income Range	Single Detached	Multi-Attached	Apartment Suite	Total
Under $25,000	16,279	2,950	9,322	28,551
$25,000-$49,999	36,531	6,131	12,447	55,139
$50,000-$74,999	36,713	7,194	6,075	49,982
$75,000-$99,999	28,087	2,605	2,678	33,370
$100,000 Plus	39,400	2,374	1,148	42,922
Total Winnipeg Non-Electric Heat Billed	157,010	21,254	31,699	209,963

Based on the 2009 Residential Survey, the breakdown of the total numbers of Residential **Electric Heat Billed** across dwelling types by annual household income for the Total Province area are as follows:

Income Range	Single Detached	Multi-Attached	Apartment Suite	Total
Under $25,000	23,112	1,841	5,762	30,715
$25,000-$49,999	39,981	2,806	6,934	49,721
$50,000-$74,999	29,629	2,001	5,027	36,657
$75,000-$99,999	16,813	1,452	1,616	19,881
$100,000 Plus	16,996	404	569	17,969
Total Province Electric Heat Billed	126,531	8,504	19,908	154,943

Based on the 2009 Residential Survey, the breakdown of the total numbers of Residential **Non-Electric Heat Billed** across dwelling types by annual household income for the Total Province area are as follows:

Income Range	**Single Detached**	**Multi-Attached**	**Apartment Suite**	**Total**
Under $25,000	25,396	4,208	10,844	40,448
$25,000-$49,999	57,700	7,400	14,061	79,161
$50,000-$74,999	52,262	7,572	6,350	66,184
$75,000-$99,999	38,302	2,757	3,120	44,179
$100,000 Plus	49,708	2,883	1,590	54,181
Total Province Non-Electric Heat Billed	223,368	24,820	35,965	284,153

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 59

PREAMBLE: To determine low income rate impact CAC MB requires the following information.

QUESTION:

For those months when Manitoba Hydro had inverted residential rates in place please indicate: i) the total number of Electric Heat customers and the number with usage in the second block and ii) the total number of non-Electric Heat customers and the number with usage in the second block.

RESPONSE:

Manitoba Hydro had inclining block rates for Residential customers during the period July 1, 2008 to March 31, 2011. The rates in effect during this time all had a first block amount of 900 kWh. The table on the following page provides the total number of actual customers (for both all-electric (electric space heat) and standard (non-electric space heat)) and the number and percentage of those which exceeded the 900 kWh first block amount.

1

REVENUE MONTH	All-Electric Customers			Standard Customers		
	Total # Accounts	# Exceeding 900 kWh	% >900 kWh	Total # Accounts	# Exceeding 900 kWh	% >900 kWh
2011 MAR	146,051	129,277	88.5%	302,002	128,442	42.5%
2011 FEB	145,792	129,389	88.7%	301,887	126,107	41.8%
2011 JAN	145,426	131,896	90.7%	302,087	154,797	51.2%
2010 DEC	145,158	126,793	87.3%	302,027	123,794	41.0%
2010 NOV	144,885	112,460	77.6%	301,809	101,754	33.7%
2010 OCT	144,437	87,727	60.7%	301,588	80,698	26.8%
2010 SEP	144,086	77,778	54.0%	301,450	95,066	31.5%
2010 AUG	143,768	76,204	53.0%	301,291	137,350	45.6%
2010 JUL	143,509	75,525	52.6%	301,147	130,395	43.3%
2010 JUN	143,344	79,045	55.1%	300,983	85,178	28.3%
2010 MAY	143,163	99,951	69.8%	300,842	84,187	28.0%
2010 APR	143,027	113,436	79.3%	300,824	100,825	33.5%
2010 MAR	142,858	122,424	85.7%	300,764	111,978	37.2%
2010 FEB	142,643	126,075	88.4%	300,773	124,528	41.4%
2010 JAN	142,321	128,811	90.5%	300,810	155,062	51.5%
2009 DEC	141,901	121,384	85.5%	300,963	115,294	38.3%
2009 NOV	141,388	111,754	79.0%	301,071	95,633	31.8%
2009 OCT	140,538	98,297	69.9%	301,457	105,670	35.1%
2009 SEP	139,802	66,620	47.7%	301,603	100,644	33.4%
2009 AUG	139,319	66,209	47.5%	301,619	97,243	32.2%
2009 JUL	139,161	69,113	49.7%	301,463	102,871	34.1%
2009 JUN	139,017	93,588	67.3%	301,251	93,715	31.1%
2009 MAY	138,936	105,067	75.6%	301,082	84,407	28.0%
2009 APR	138,870	118,131	85.1%	300,911	114,197	38.0%
2009 MAR	138,798	122,824	88.5%	300,722	118,107	39.3%
2009 FEB	138,706	123,986	89.4%	300,645	129,375	43.0%
2009 JAN	138,486	126,851	91.6%	300,517	160,894	53.5%
2008 DEC	138,270	121,279	87.7%	300,449	118,597	39.5%
2008 NOV	137,949	109,730	79.5%	300,277	100,328	33.4%
2008 OCT	137,647	87,901	63.9%	299,997	81,381	27.1%
2008 SEP	137,321	73,958	53.9%	299,608	103,657	34.6%
2008 AUG	136,940	64,738	47.3%	299,478	115,266	38.5%
2008 JUL	136,585	63,208	46.3%	299,389	102,502	34.2%

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 59

PREAMBLE: To determine low income rate impact CAC MB requires the following information.

QUESTION:

Does Manitoba Hydro have any data as to how usage by dwelling type (or simply overall) varies by income for Electric Heat Billed residential customers?

RESPONSE:

Data as to how usage by dwelling type (or simply overall) varies by income for Electric Heat Billed residential customers is available upon the information collected under the 2009 residential survey. Please see Manitoba Hydro's response to CAC/MH I-191 (b).

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 59

PREAMBLE: To determine low income rate impact CAC MB requires the following information.

QUESTION:

If yes, please provide and breakdown by dwelling type if possible.

RESPONSE:

The following table shows how average annual usage (kilowatt hours) varies by income across dwelling type (or simply overall) for **Electric Heat Billed** residential customers.

Income Range	Single Detached	Multi-Attached	Apartment Suite	Overall
Under $25,000	23,233	16,152	7,946	19,941
$25,000-$49,999	28,146	15,261	8,847	24,727
$50,000-$74,999	29,316	17,271	9,330	25,918
$75,000-$99,999	31,902	17,546	10,711	29,131
$100,000 Plus	32,254	15,882	12,668	31267
Overall	28,574	16,346	8,969	25,384

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 59

PREAMBLE: To determine low income rate impact CAC MB requires the following information.

QUESTION:

Does Manitoba Hydro have any data as to how usage by dwelling type (or simply overall) varies by income for non-Electric Heat Billed residential customers?

RESPONSE:

Data as to how usage by dwelling type (or simply overall) varies by income for Non-Electric Heat Billed residential customers is available based upon information collected under the 2009 residential survey. Please see Manitoba Hydro's response to Round 1 CAC-0192 (b).

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 59

PREAMBLE: To determine low income rate impact CAC MB requires the following information.

QUESTION:

If yes, please provide and breakdown by dwelling type if possible.

RESPONSE:

The following table shows how average annual usage (kilowatt hours) varies by income across dwelling type (or simply overall) for **Non-Electric Heat Billed** residential customers.

Income Range	Single Detached	Multi-Attached	Apartment Suite	Overall
Under $25,000	7,820	6,836	3,453	6,547
$25,000-$49,999	9,894	6,964	3,701	8,520
$50,000-$74,999	11,897	8,227	4,372	10,755
$75,000-$99,999	12,154	10,247	8,949	11,808
$100,000 Plus	14,636	10,850	8,607	14,257
Overall	11,570	8,143	4,417	10,365

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 59

PREAMBLE: To determine low income rate impact CAC MB requires the following information.

QUESTION:

Does Manitoba Hydro have any data regarding home-ownership by dwelling and/or by heating type?

RESPONSE:

Data regarding home ownership for residential customers by dwelling type and space heating type is available based upon information collected under the 2009 residential survey. Please see Manitoba Hydro's response to CAC/MH I-193 (b).

REFERENCE: Appendix D 2013 Electric Load Forecast; Page No.: 59

PREAMBLE: To determine low income rate impact CAC MB requires the following information.

QUESTION:

If yes, please provide the following for the Winnipeg area and for the total province: i) breakdown of Housing type by ownership vs. rental; ii) breakdown of Heating type by ownership vs. rental; and iii) a breakdown of Housing/Heating type by ownership vs. rental.

RESPONSE:

(i) Based on the 2009 Residential Survey, the breakdown of the total numbers of Residential dwelling types by home ownership for the Winnipeg area are as follows:

Ownership	Single Detached	Multi-Attached	Apartment Suite	Total
Own	159,015	21,007	13,722	193,744
Rent	4,018	5,572	32,759	42,349
Total Winnipeg	163,033	26,579	46,481	236,093

Based on the 2009 Residential Survey, the breakdown of the total numbers of Residential dwelling types by home ownership for the Total Province are as follows:

Ownership	Single Detached	Multi-Attached	Apartment Suite	Total
Own	338,902	24.301	16,906	380,110
Rent	10,997	9,023	38,967	58,986
Total Province	349,899	33,324	55,873	439,096

(ii) Based on the 2009 Residential Survey, the breakdown of the total numbers of Residential heating types by home ownership for the Winnipeg area are as follows:

Ownership	Electric Heat Billed	Non-Electric Heat Billed	Total
Own	15,032	178,712	193,744
Rent	11,098	31,251	42,349
Total Winnipeg	26,130	209,963	236,093

Based on the 2009 Residential Survey, the breakdown of the total numbers of Residential heating types by home ownership for the Total Province are as follows:

Ownership	Electric Heat Billed	Non-Electric Heat Billed	Total
Own	133,034	247,076	380,110
Rent	21,909	37,077	58,986
Total Province	154,943	284,153	439,096

(iii) Based on the 2009 Residential Survey, the breakdown of the total numbers of Residential **Electric Heat Billed** across dwelling types by annual homeownership for the Winnipeg area are as follows:

Ownership	Single Detached	Multi-Attached	Apartment Suite	Total
Own	5,882	3,465	5,685	15,032
Rent	141	1,860	9,097	11,098
Total Winnipeg Electric Heat Billed	6,023	5,325	14,782	26,130

Based on the 2009 Residential Survey, the breakdown of the total numbers of Residential **Non-Electric Heat Billed** across dwelling types by homeownership for the Winnipeg area are as follows:

Ownership	Single Detached	Multi-Attached	Apartment Suite	Total
Own	153,133	17,542	8,037	178,712
Rent	3,877	3,712	23,662	31,251
Total Winnipeg Non-Electric Heat Billed	157,010	21,254	31,699	209,963

Based on the 2009 Residential Survey, the breakdown of the total numbers of Residential **Electric Heat Billed** across dwelling types by homeownership for the Total Province area are as follows:

Ownership	Single Detached	Multi-Attached	Apartment Suite	Total
Own	120,939	4,807	7,288	133,034
Rent	5,592	3,697	12,620	21,909
Total Province Electric Heat Billed	126,531	8,504	19,908	154,943

Based on the 2009 Residential Survey, the breakdown of the total numbers of Residential **Non-Electric Heat Billed** across dwelling types by homeownership for the Total Province area are as follows:

Ownership	Single Detached	Multi-Attached	Apartment Suite	Total
Own	217,963	19,494	9,618	247,075
Rent	5,405	5,326	26,347	37,078
Total Province Non-Electric Heat Billed	223,368	24,820	35,965	284,153

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Page No.: 7

PREAMBLE: In chapter 3, page 7 Manitoba Hydro suggests there are linkages between electricity prices and demand.

QUESTION:

Please provide a summary of residential electrical tariff charges by block for the years 2000 through 2013.

RESPONSE:

Please see Manitoba Hydro's response to CAC/MH I-139.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.1; Page No.: 5

QUESTION:

Please confirm that the same capital cost for Bipole III is included in all Plans.

RESPONSE:

The same Bipole III costs are common to all development plans.

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.1; Page No.: 5

QUESTION:

What is the cost of Bipole III as included in the Financial Evaluations and is it the same as the cost presented to the CEC in the recent hearings regarding Bipole III?

RESPONSE:

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

REFERENCE: Chapter 11: Financial Evaluation of Development Plans; Section: 11.1; Page No.: 5

QUESTION:

What level of cost contingency is built into the capital cost estimate used for Bipole III (e.g. is it P50)?

RESPONSE:

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

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply.

PREAMBLE: Chapter 3, page 1, lines 21-23 and Chapter 5, page 56, lines 21-24 present EIA's reference case load growth for the U.S. (0.9% annual). The West North Central division (ND, SD, NE, KS, MN, IA, and MO) has a 0.6% annual growth rate in EIA's reference case. The East North Central division (WI, IL, MI, IN, OH) has a 0.3% annual growth rate in EIA's reference case.

QUESTION:

Would the load growth rates for the West North Central and East North Central census divisions be a more appropriate indicator? If not, why not?

RESPONSE:

The West North Central and East North Central are US Census Divisions used for data aggregation and reporting purposes by the US Energy Information Administration (EIA). Neither division is wholly representative of Manitoba Hydro's US export market and/or the MISO RTO, thus neither division would be considered more appropriate for evaluating projected electricity load growth rates. For instance, the West North Central division represents North Dakota and Minnesota, among other states; the East North Central division represents Wisconsin, among other states.

While useful as a publicly-available source of information, the US EIA Annual Energy Outlook presents only one view of future energy supply/demand trends. The NFAT business case utilizes a consensus approach that includes outlooks of a variety of respected and independent consulting organizations.

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: 3.1; Page No.: 1

PREAMBLE: It is understood that the EIA produces load forecasts for the various regions of the US

QUESTION:

What is/are the EIA reference case projection(s) for the regions of the US that MISO incorporates? In particular, for those specific regions that encompass Minnesota and Wisconsin.

RESPONSE:

As noted in the response to CAC/MH I-196a, the EIA does not provide a reference case projection that is wholly representative of the regions of the US that MISO incorporates.

REFERENCE:

QUESTION:

Does the EIA reference case load forecast assume that there are costs associated with CO2 emissions? If so, what are the assumptions?

RESPONSE:

The EIA reference case does not incorporate any future changes in policy directed at carbon emissions or other environmental issues, but does include projected impacts from existing legislation such as the federal light duty vehicle GHG and Corporate Average Fuel Economy (CAFE) standards, and California's Global Warming Solutions Act (AB32).

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.6.1.2; Page No.: 56

PREAMBLE: Chapter 5, page 56, line 21 and Chapter 6, page 7, lines 7-10 give the MISO annual load growth rate of 0.91-0.95%.

QUESTION:

Does MISO produce demand forecasts for the various load resource zones? If so, what are MISO's base-case demand growth assumption for the zones/regions that Manitoba Hydro exports to?

RESPONSE:

Table 4.3-1 of the MISO Transmission Expansion Plan 2012 (MTEP) contains the following summer peak loads by region. Manitoba Hydro is interconnected with the West Sub Region.

Scenario	West Sub Region Load	Central Sub Region Load	East Sub Region Load	Total MISO Load
2014 Summer Peak (MW)	42,061	35,186	24975	102,222
2022 Summer Peak (MW)	45,454	37,112	26,495	109,061
Increase (MW)	3,393	1,926	1,520	6,839
Calculated Compounded Annual Growth Rate (%)	0.97	0.67	0.74	0.81

Manitoba Hydro notes that these sub-region load forecasts are directly based on MISO member data, and vary slightly from the MISO aggregated forecasts referenced in Chapter 5, page 56 and Chapter 6, page 7 of the NFAT Business Case.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.6.1.2; Page No.: 56

PREAMBLE: It is understood that the EIA produces various load forecasts that do include CO2 cost assumptions.

QUESTION:

What would be the load growth projections for the US overall and for the specific EIA regions incorporating MISO regional markets that Manitoba Hydro exports to using the EIA case that is most similar to the situation assumed in Manitoba Hydro's export market price forecast?

RESPONSE:

The Energy Information Administration of the US Department of Energy (DOE EIA) produced over 25 cases as part of their 2013 Annual Energy Outlook (AEO). Manitoba Hydro has not conducted a detailed review and comparison of these AEO cases with that used in the export market price forecast, and therefore it is not in a position to identify which, if any, case in the AEO would be most similar to that of the consensus of the electricity price forecast consultants. Manitoba Hydro would not be able to publically identify such a case, should it actually exist, as to do so would give significant insights into the electricity price forecast.

Information on the load growth projections is contained with the export market price forecast and supporting documents. Manitoba Hydro's export market price forecasts and related supporting documents are considered Commercially Sensitive Information pursuant to the Terms of Reference - Needs For and Alternatives To (NFAT) Review and have been filed as such in these proceedings.

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.2.1; Page No.: 7

PREAMBLE: Chapter 6, pages 7-9 present load growth projections from resource plans for Minnesota Power and Northern States Power as well as the Wisconsin Strategic Energy Assessment.

QUESTION:

Are the load growth projections prior to (or after) the effect of any demand-side management options that may be chosen as a resource in the plans?

RESPONSE:

It is confirmed that the load growth projections quoted in Section 6.2.1 (Chapter 6, pages 7-9) of the NFAT Filing would incorporate the net load impact of approved demand side management programs

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.2.1; Page No.: 7

PREAMBLE: The market price forecast appears to include costs associated with CO_2 emissions, yet the load growth assumptions may not. The EIA reference case load growth does not have CO_2 costs (EIA has a number of separate cases with CO_2 costs included). The load growth projections reported for MISO, the Minnesota utilities, and Wisconsin do not state whether CO_2 costs are assumed.

QUESTION:

What are the CO_2 cost assumptions underlying the load growth projections cited for MISO, Minnesota Power, Northern States Power and the State of Wisconsin on pages 7-8?

RESPONSE:

The basis for Manitoba Hydro's export price forecasts are the independent consultant price forecast as detailed in Section 1.5 of Appendix 9.3 of the NFAT Filing. The load growth assumptions for the EIA, MISO, and the Minnesota utilities are provided for comparison purposes only.

MISO's load forecast is based on their Business As Usual case which assumes a $0/ton carbon price. MISO does apply a carbon price of $50/ton in only one of five "futures" scenarios they run (i.e. "Combined Policy Future"). Northern States Power did not use a carbon price in their base case however did run sensitivities with mid-and-high pricing levels ($21.50/ton and $34/ton respectively) consistent with what was directed by the Minnesota Public Utility Commission. Minnesota Power applied a price of $2.50/ton in 2013 to $3.50/ton in 2027. Similar to NSP, Minnesota Power also undertook a sensitivity case with carbon prices starting at the Minnesota PUC's midpoint analysis of $21.50/ton beginning in 2017.

The State of Wisconsin's Strategic Energy Assessment document does not have any direct references to carbon dioxide or carbon pricing in their report or associated analysis. Unlike their Minnesota counterparts, Wisconsin utilities are not obligated to incorporate carbon pricing in their resource plan assessments. As Wisconsin utilities resource plans are not publicly available, it is not clear if or at what level, carbon cost considerations are being taken into account by Wisconsin utilities.

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: 3.3.4; Page No.: 21

PREAMBLE: It is understood that, while unsuccessful, legislation has recently been introduced in a number of states (including Minnesota and Wisconsin) to repeal their RPS. Information on attempts to repeal RPS can be found at http://www.midwestenergynews.com/2013/06/04/state-renewable-energy-laws-survive-repeal-attempts-so-far/

QUESTION:

Please reconcile this trend with the outlook for RPS described on pages 21-22 of Chapter 3

RESPONSE:

The article quoted was a short news article rather than a comprehensive review of all legislative proposals related to Renewable Portfolio Standards. The news article does note that, "At least a half-dozen states saw an introduction of legislation to repeal or weaken RPS laws, though none has been enacted. And renewable proponents were able to go on the offense in a few states like Colorado, where legislators voted to strengthen an existing RPS."

A much more comprehensive review of all legislative proposals related to RPS' up to April 2013 was produced by Jason and Chelsea Barnes from the legal firm Keyes, Fox and Wideman. The paper is available at:

www.cleanenergystates.org/assets/2013-Files/RPS/2013RPSLegislationKFWBarnes.pdf.

The Keyes, Fox and Wideman paper provides a much more broad analysis related to the numerous active legislative proposals related to both strengthening and weakening RPS standards. Their detailed analysis shows that there is a relatively equal number of RPS strengthening and weakening legislation currently being considered, in a few cases with dueling

proposals in the same state. They also note that the historical record shows that no RPS has been successfully repealed, despite a less supportive legislative environment in the recent years.

The data shows that there are only 6 active proposals to repeal RPS standards, with none of the states contained within the MISO market region. This is contrasted with 25 active proposals to establish or expand RPS standards. Also the paper notes that of the nine RPS repeal efforts between 2011-2013, none have succeeded.

Further it should be noted that 2/3 of the active "weakening" proposals are related to expansion of existing technology definitions or expansion of geographic eligibility, both that would be considered positive developments for Canadian hydropower resources. The paper notes specifically that there are 17 pending legislative proposals across nine states to expand their definition of eligible hydropower facilities either related to size, age or geographic location of the resource. Contrast this with only 6 proposals to tighten geographic or resource eligibility standards across all technologies and regions (with no indication any relate directly to hydropower).

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Page No.: 42

QUESTION:

How sensitive is the range of electricity prices generated in Appendix 9.3 (pages 42-43) to carbon price assumptions (e.g. is it natural gas prices or carbon pricing that creates the greater uncertainty)?

RESPONSE:

It can be stated that variability across future natural gas prices (i.e. range between high and low values) is the primary uncertainty (relative to carbon) across the various cases (Low, Reference & High) of the export electricity price forecast.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Page No.: 42

PREAMBLE: It is also understood that there have been attempts at the Federal level in the U.S. to block the U.S. EPA from producing greenhouse gas regulations. Manitoba Hydro states it believes "some form of significant climate change action in the U.S. is likely within the next 10 years" (Chapter 3, page 35).

QUESTION:

Does the low carbon price case assume some form of carbon pricing within the next 10 years?

RESPONSE:

The low carbon price case for the Reference Scenario and the 2013 Update assumes no value (i.e. $0/tonne CO2) for carbon across the forecast horizon.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Page No.: 42

PREAMBLE: It is also understood that there have been attempts at the Federal level in the US to block the US EPA from producing greenhouse gas regulations. Manitoba Hydro states it believes "some form of significant climate change action in the US is likely within the next 10 years" (Chapter 3, page 35).

QUESTION:

What is the difference in the timing of the introduction of carbon pricing as between the low and high carbon cost forecasts?

RESPONSE:

Manitoba Hydro's export market price forecasts and related supporting documents are considered Commercially Sensitive Information pursuant to the Terms of Reference - Needs For and Alternatives To (NFAT) Review.

As a point of reference, The Brattle Group's assumptions regarding carbon prices in their various scenarios can be found on Appendix 3.1 – Page 28 of the NFAT submission.

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: 3.4.2; Page No.: 30

PREAMBLE: Figure 3.12 shows significant natural gas prices spikes around 2005 and 2008.

QUESTION:

Please comment on the underlying reasons for these gas price spikes and, in particular, whether they were related to major hurricanes in the Gulf of Mexico in 2005 (Katrina and Rita) and 2008 (Gustav and Ike).

RESPONSE:

According to the U.S. Department of Energy (DOE), the natural gas price spikes of 2005 and 2008 were significantly related to the impact of the major hurricanes which struck the Gulf of Mexico at those times causing supply disruption and infrastructure damage. As Hurricane Katrina approached the Gulf of Mexico in late August 2005, 88% of total Gulf natural gas production (nearly 20% of total U.S. production at the time) was shut down as a precaution. As Hurricane Gustav approached the Gulf in late August-early September 2008, 95% of total Gulf natural gas production was shut down. After each hurricane season, undamaged production facilities were quickly restored to service, but damage to production platforms, pipelines, and processing facilities was extensive.

It should also be noted that there are many other factors that drove the natural gas price movements of that period. During this time, the price of energy commodities was impacted by worries over rapidly growing demand from the developing world, perceptions of general scarcity of supplies in the future and heavy speculative financial interest in commodities in general from the money management community.

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: 3.4.2; Page No.: 30

PREAMBLE: Figure 3.12 shows significant natural gas prices spikes around 2005 and 2008.

QUESTION:

Does the increasing reliance on shale gas make a repeat of the past supply disruptions less likely and, thereby, reduce the future volatility of natural gas prices?

RESPONSE:

According to the U.S. EIA, disruptions to oil and natural gas production from hurricanes in the Gulf of Mexico have declined in recent years because of regional shifts in production; that is, a greater proportion of production is now taking place in inland shale basins. The EIA notes that in 1997, 26% of U.S. natural gas production occurred in the federal Gulf of Mexico; in 2012 that proportion had declined to 6%.

It may be possible that if current regional production trends continued in the future, increased reliance on shale gas would have the potential to reduce the portion of natural gas price volatility associated with hurricanes.

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: 3.6; Page No.: 41

PREAMBLE: The Submission states that utilities will seek to mitigate expected natural gas price uncertainty and volatility.

QUESTION:

How volatile have natural gas prices been in recent years (e.g. the last 5) as compared to historically and what level of volatility is "expected" in the future?

RESPONSE:

A study of historical natural gas price volatility completed by the U.S. Energy Information Administration (EIA) in 2007 concluded that annual price volatility at Henry Hub has been high for the past decade, but did not exhibit a consistent increasing or decreasing trend. Examination of post-2006 data reveals that trend volatility has been gradually declining since the time of the study, but results will vary depending on the specific North American natural gas hub chosen.

There remains substantial uncertainty related to future environmental policy and with the ultimate size and load shape of new demand sources (LNG, power sector, transportation etc.). Due to these and many other influencing factors, the future levels of natural gas price volatility are inherently uncertain.

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: 3.4.2; Page No.: 32

PREAMBLE: The Submission indicates that the high prices of natural gas liquids are currently offsetting the extraction cost of natural gas.

QUESTION:

Please comment on Manitoba Hydro's understanding as to whether the primary financial driver for hydraulic fracturing is the liquids or the natural gas (i.e. is the true relationship really that the natural gas production helps offset the cost of the liquids?).

RESPONSE:

The production of associated natural gas liquids contributes positively to the economics of natural gas production due to their current higher market prices relative to dry gas on an equivalent unit of energy basis.

However, each individual natural gas production decision is based on multiple factors that include not only liquids potential, but basin geology, relative drilling efficiencies, proximity to end-use markets and capital availability.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1; Page No.: 8

QUESTION:

Does the EIA produce wholesale electricity price forecasts? If so, please provide its most recent reference forecast for those regions including Minnesota and Wisconsin.

RESPONSE:

It is Manitoba Hydro's understanding that the EIA does not produce wholesale electricity price forecasts.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1; Page No.: 8

QUESTION:

Please also provide any alternative wholesale electricity price forecasts by the EIA for these regions and indicate the carbon and natural gas pricing assumptions underlying each.

RESPONSE:

As noted in response to CAC/MH I-207a, it is Manitoba Hydro's understanding that the EIA does not produce wholesale electricity price forecasts.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1; Page No.: 8

QUESTION:

How do the EIA's price forecasts compare with those prepared by Manitoba Hydro?

RESPONSE:

As noted in the response to CAC/MH I-207a, it is Manitoba Hydro's understanding that the EIA does not produce wholesale electricity price forecasts that would be comparable to the forecasts utilized by Manitoba Hydro.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1; Page No.: 8

QUESTION:

If the EIA does not produce wholesale electricity price forecasts, does it produce retail electricity price forecasts? If yes, please provide its most recent reference case forecast for those regions including Minnesota and Wisconsin.

RESPONSE:

Yes, the EIA produces a retail price forecast. It is included in its 2013 Annual Energy Outlook. This is a publicly available document that can be access by any individual through the EIA's web portal at: http://www.eia.gov/forecasts/aeo/

Wholesale electricity prices are only one component of average retail prices paid by various sector customers across the different regions of the US. A number of factors beyond wholesale electricity prices, including distribution system costs, the mix of competitive versus cost-of-service pricing, and the number of customers who purchase power directly from wholesale power markets also influence the retail price forecast. It is unclear how one would infer regional wholesale energy market prices trends from retail values averaged across all customer sectors without any additional methodology or assumptions being available.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1; Page No.: 8

QUESTION:

In the case of the EIA's most recent retail electricity reference case price forecast, what are the underlying natural gas price and carbon pricing assumptions?

RESPONSE:

The referenced U.S. Energy Information Administration (EIA) retail electricity price forecast is a publicly available document which Manitoba Hydro accesses at the EIA's website http://www.eia.gov. Manitoba Hydro does not have specific insights or knowledge of the forecast beyond what can be garnered from the website, hence it would not be appropriate to comment on underlying modeling assumptions.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1; Page No.: 8

QUESTION:

Please provide any alternative retail electricity price forecasts produced by the EIA for these regions and indicate the natural gas/carbon pricing assumption associated with each.

RESPONSE:

As noted in response to CAC/MH I-208b, it is not appropriate that Manitoba Hydro comment on underlying modeling assumptions used by the EIA.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1; Page No.: 8

QUESTION:

Which retail electricity price case uses natural gas/carbon pricing assumptions most closely aligned with Manitoba Hydro's export price forecast?

RESPONSE:

As noted in response to CAC/MH I-208b, it is not appropriate for Manitoba Hydro to comment on underlying modeling assumptions used by the EIA.

Manitoba Hydro has filed the 2012 and 2013 Electricity Export Price Forecast reports for review as part of the NFAT's CSI process.

REFERENCE: Appendix 9.3 Economic Evaluation Documentation; Section: 1.5.1; Page No.: 8

QUESTION:

Do the consultant's export price forecasts factor in Manitoba Hydro's proposed hydroelectric generation developments into their models and analysis?

RESPONSE:

Manitoba Hydro's proposed hydroelectric development plans are made available to the price forecast consultants that they may incorporate them as they deem appropriate.

It should be noted that the long term forecasting models analyze the cost of generation over large market regions. New exports from Manitoba will tend to displace the construction of other dispatchable generation capacity, in quantities that are relatively small relative to the large market region. Therefore the impact that new Manitoba Hydro generation would have on the overall long term regional price is minimal as long as there are no transmission constraints.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.5; Page No.: 55

PREAMBLE: Chapter 5 indicates that Manitoba Hydro's long term export price forecast includes the value of RECs.

QUESTION:

Is this done as an adder? If so, how does Manitoba Hydro insure the value is not already captured in the component market price forecasts?

RESPONSE:

The statement in Chapter 5, Section 5.5 at page 55 “As such Manitoba Hydro’s long-term export price forecast does include the value of RECs” should have read “As such Manitoba Hydro’s long-term export price forecast does not include the value of RECs”. Therefore the REC value is not already captured in the component market price forecasts.

The export price consultants generally do incorporate compliance with state mandated renewable portfolio standards (RPSs) into their models. The impact of such state RPSs will have on stimulating new wind generation or other specified generation and any resulting effects on the construction of other generation resources and in turn energy prices will be considered within their price forecasting models. However, there is no explicit REC price forecast within the Electricity Export Price Forecast.

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.1.4; Page No.: 5

PREAMBLE: Chapter 6 suggests that either RPS or transmission rate of return incentives may have less influence in the future.

QUESTION:

Is it also not feasible that these factors could have more of an influence in the future such that the incentives will increase (not decrease)? If not, why not?

RESPONSE:

The current pressure on U.S. RPS and transmission rate of return incentives is in the direction of reducing their influence on future US transmission construction and there is at present no sign of a reversal of that trend. Current federal U.S. wind power incentives, particularly the Production Tax Credit, have stimulated wind generation construction in the U.S. to the point where more wind power has now been constructed than required to meet current renewable portfolio standards. For example, Minnesota Power stated in their 2013 Resource Plan filing that "With 400 MW of competitive wind projects already present in its portfolio, Minnesota Power is ahead of its renewable energy standard ("RES") requirements and is closely monitoring the need for additional intermittent renewable energy." A reduced need for wind generation in the future would likely create less demand for transmission construction to meet RPS requirements.

As explained in Manitoba Hydro's response to CAC/MH I-212, the November 15, 2012 FERC Policy Statement titled Promoting Transmission Investment Through Pricing Reform effectively set the bar to receive such incentives higher, and creates uncertainty as to what types of steps FERC will require to mitigate risks of a transmission project before an applicant can seek an incentive return on equity. The greater uncertainty/ difficulty in obtaining incentive ROEs and

downward pressure on transmission ROE in general combine to reduce incentives for new transmission construction.

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.1.4; Page No.: 6

PREAMBLE: Chapter 6 discusses the FERC incentives on electric transmission infrastructure and indicates that FERC issued a policy statement in November 2012 to provide further guidance on transmission incentives.

QUESTION:

What in the November 2012 policy statement leads to Manitoba Hydro's concern that there will be "reduced transmission incentives for investor-owned utilities in the US" (lines 18-20)?

RESPONSE:

There is a constituency in the U.S. which is pushing for both reduced base transmission rates of return on equity (ROEs) for utilities as well as reduced transmission incentive policies/ ROEs for new transmission projects. When FERC issued a notice of inquiry on May 19, 2011 on the scope and implementation of transmission incentive regulations and policies, it received over 1,500 pages of comments reflecting a wide range of perspectives under Order No. 679.

A number of comments were not supportive of the transmission incentive policies. For example, ELCON, the national U.S. association representing large industrial consumers of Electricity, stated “In the five years since FERC issued its current transmission incentives policy in Orders 679 and 679-A, it has become clear that the policy has failed to adequately protect consumer interests”.

The subsequent November 15, 2012 FERC Policy Statement titled Promoting Transmission Investment Through Pricing Reform provided guidance regarding FERC’s own evaluation of applications for electric transmission incentives. The general tone of this FERC Policy Statement was to reframe and focus requirements from previous Order 679 titled Promoting Transmission

Investment through Pricing Reform. FERC now expects applicants for transmission incentives to take all reasonable steps to mitigate the risks of a project including requesting those incentives designed to reduce the risk of a project, before seeking an incentive return on equity (ROE) based on a project's risks and challenges. This effectively set the bar to receive such incentives higher, and creates uncertainty as to what types of steps FERC will require to mitigate risks of a transmission project before an applicant can seek an incentive return on equity.

In addition, FERC continues to utilize a discounted flow analysis in determining ROE's resulting in lower ROE's and thus a disincentive to construct new transmission facilities. There are cases currently before FERC challenging existing ROE's and some market participants have asked FERC to take a generic look what they feel are generous ROE policies through a formal rulemaking.

Debate on transmission incentives and returns on equity continues in the U.S. For example, on July 12, 2013, a group of U.S. public utility commissions, industrial electric customers, public power systems, rural electric cooperatives, state consumer advocates and associated trade associations, nonprofit consumer advocacy organizations, and environmental organizations collectively known as the Joint Signatories filed comments on the issue of Transmission Rates of Return on Equity stating:

"Our primary message is simple—the Commission [FERC] should continue to scrutinize public utilities' transmission rates to ensure that all elements, including ROE allowances, remain just and reasonable in light of changing economic conditions and factors, as the Federal Power Act requires. The FPA allows public utilities to earn a return sufficient to attract capital from investors; it does not require the continued payment of ROE allowances that are unduly high given changed economic conditions, simply because at some point in the past, the Commission found such an ROE just and reasonable under then-prevailing circumstances. The Commission also should not abandon the Discounted Cash Flow ("DCF") methodology it now uses to

determine ROE allowances just because it no longer produces the same ROE awards that it did prior to 2008. Economic conditions throughout the Nation (if not the world) have fundamentally changed since that time. In the past five years, electric consumers have suffered through decreased employment, shrinking paychecks, home foreclosures, and myriad other economic losses. Industrial consumers also have faced extraordinary economic challenges, including decreased demand and aggressive foreign competition. EEI's arguments that its members' high pre-2008 ROE allowances cannot be reduced without disappointing investors must be weighed against these hard facts."

REFERENCE: Chapter 6: The Window of Opportunity; Section: 6.3.1; Page No.: 23

PREAMBLE: The Wind Synergy Study indicates that there will be a reduction in locational marginal energy prices.

QUESTION:

Does this mean the Manitoba Hydro will receive a lower price for its exports into the US market? Apart for increased wind imports in the off-peak, what are the benefits to Manitoba Hydro's customers?

RESPONSE:

MISO's Manitoba Hydro Wind Synergy Study (MHWSS) showed that prices will be affected by Manitoba Hydro's Preferred Development Plan. However the new transmission line allows more surplus on peak energy sales and more low cost off peak energy purchases than without the line. As a result overall net export revenues increase for the benefit of Manitoba Hydro.

The MHWSS indicated that the new transmission line will more closely connect the Manitoba system which has surplus generation to Minnesota bringing the market prices in the two areas closer together.

The market price in the importing area will be slightly reduced by the availability of more market priced energy and the market price in the exporting area would be slightly increased as its energy is being sold at market prices higher than in its domestic region.

Any large additional supply of market priced energy will tend to reduce the cost of energy for customers but this effect is small because the MISO market is very large compared to the amount of new generation being made available by Manitoba Hydro.

Where the generator and MISO load are selling and buying energy at market prices, both can expect to benefit as the generator receives a higher price than if its energy could not reach the MISO load and the MISO load benefits by paying a lower price than it would without access to the additional market-priced energy.

The average price Manitoba Hydro receives for its exports to the US market is a blend of MISO day-ahead and real-time market prices for surplus energy and contracted prices for energy sales. The new interconnection allows Manitoba Hydro to sell a long term product of capacity and dependable energy on firm transmission at negotiated prices that are at a premium to expected market prices for energy.

Other benefits to Manitoba Hydro indicated from the modeling in MHWSS associated with the addition of new hydropower in Manitoba and a new 500 kV transmission line include:

a) Increased revenue from exported energy because more energy can be delivered to US markets when it is most valuable (on-peak) and less energy need be delivered to US markets off-peak when it would compete with wind generation in northern MISO

b) Increased revenue from selling ancillary services to the MISO market

c) Increased revenue from increased opportunities to sell generation capacity into the MISO market which were not evaluated in the MHWSS

Additional benefits to Manitoba Hydro's domestic customers which were beyond the scope of the MHWSS but which also result from new hydropower in Manitoba and a new 500 kV transmission line include:

a) Favorable recognition in US markets of the complementary nature of new renewable hydropower in Manitoba and planned wind power development in MISO. As a result new hydro is not seen as a competitor to US wind but rather as necessary to enable additional wind

development. This recognition may result in US decision makers and regulators being even more supportive of imports from Manitoba Hydro. The substantial Load Cost Savings identified by the MHWSS and the displacement of carbon-based energy in MISO with carbon-free energy from Manitoba are two significant benefits for US consumers which are important to US decision makers and regulators.

b) Increased import opportunities which includes access to a greater volume of inexpensive off-peak energy from MISO reducing the cost to supply customer load in Manitoba.

c) Increased reliability resulting from an increased ability for Manitoba Hydro to import energy on a larger interconnection in emergencies and in droughts. A larger interconnection also reduces the risk of a power system blackout for both Manitoba and MISO when severe power system disturbances occur as a result of weather, major equipment failure or sabotage.

d) Reduced lost opportunity costs (such as lost export revenues) during outages will result with two 500 kV transmission lines to the US instead of just one because it will be less disruptive to take a 500 kV line out of service for maintenance when there are two such lines.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.1; Page No.: 37

PREAMBLE: The EIA provides data on generation sources by state.

QUESTION:

Please confirm that in 2011 Minnesota generated 53% of its electricity from coal and for Wisconsin the proportion was 63%.

RESPONSE:

It is confirmed that the percentages of electricity generated by facilities within those two specific states are correct. However it must be noted that MISO does not dispatch generation within a state to meet only the loads within a state. Rather MISO dispatches the entire regional generation fleet to meet the aggregate load of the region, subject to transmission limits, and without regard to state boundaries.

For example, Minnesota generated 53 terawatt hours (TWh) of electricity in 2011 while retail sales in the state were 68 TWh, meaning they generated only 77% of their state electricity needs domestically. Conversely, in 2011 North Dakota generated electricity equivalent to over 250% of their state's retail sales, therefore had to export much of their generation to neighboring regions, namely Minnesota. It should also be noted that North Dakota generated 77% of their electricity with coal in 2011.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.2.4; Page No.: 46

PREAMBLE: The Submission claims that coal-fired resources set energy prices in 93% of the intervals (Chapter 5, page 45) and that wind generators set prices only in small transmission-constrained areas (Chapter 5, page 46)

QUESTION:

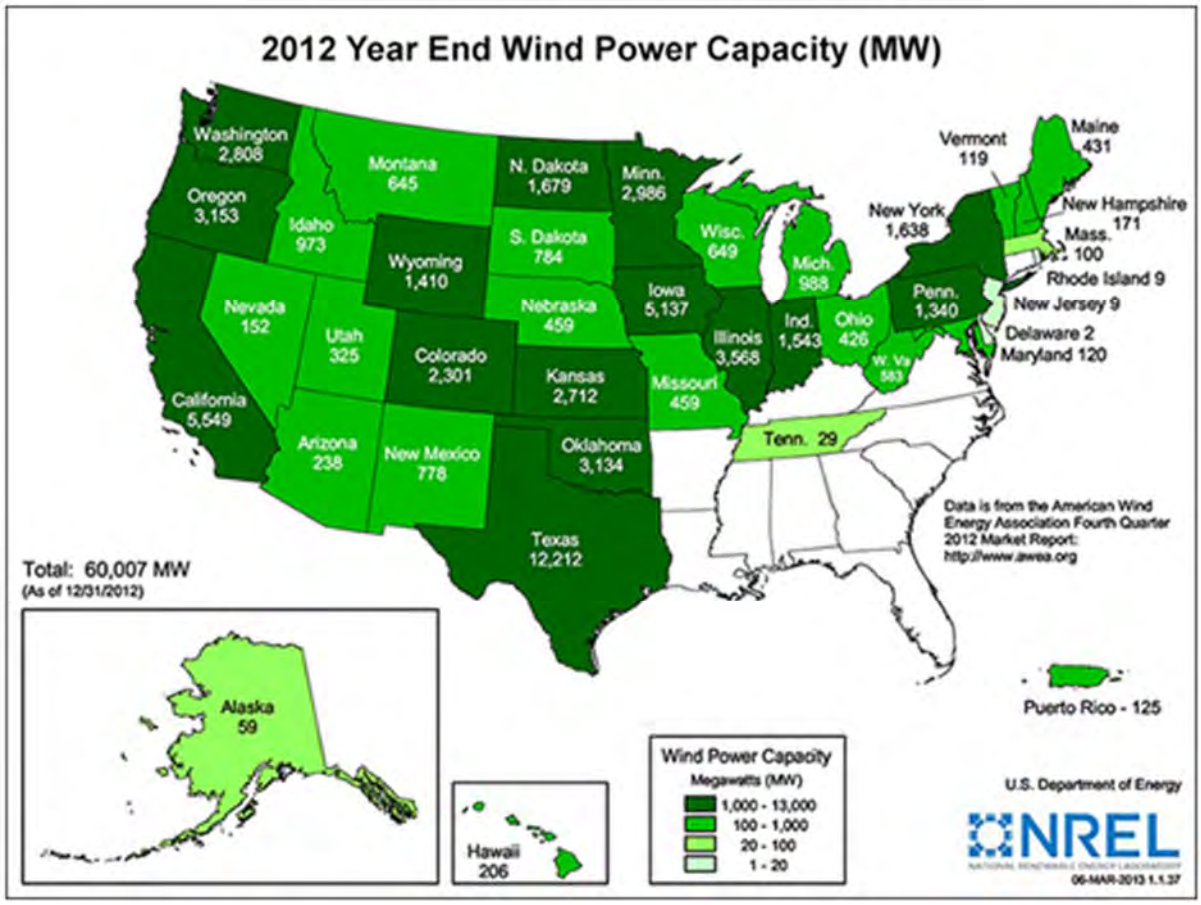
Please confirm that most of the wind generation is in the areas that Manitoba Hydro is selling into and comment on how relevant wind-generation is in setting prices in these markets.

RESPONSE:

Manitoba Hydro cannot confirm that most of the wind generation is in the areas that Manitoba Hydro is selling into based upon our review of wind generation data available at the state level for the areas that Manitoba Hydro is selling into. This includes Minnesota, North Dakota and Wisconsin as well as for the US EIA regions of the East North Central and West North Central which is representative of the MISO market in 2012.

According to EIA 2012 net generation statistics, the East North Central and West North Central regions produced a total of 51,856 GWh of wind generation. Of that total, only 27% was generated in Minnesota, North Dakota and Wisconsin combined.

The graphic below provides installed capacity of wind generation by US state which is consistent with the 2012 generation statistics. The majority of wind generation in MISO is southeast of the Minneapolis load center in the Iowa and Illinois region.



Overall, additional wind generation has a slight suppression effect on overall MISO electricity prices, the extent of which is considered within the electricity export price forecast analysis. The precise impact of wind generation on setting market prices at any particular grid location is harder to quantify. Hourly resolution data with regard to which specific generator is setting the marginal market price at any particular pricing node which could be used to determine when wind generation is setting the market price in various regions is not publically available as far as Manitoba Hydro is aware.

The 2012 MISO IMM noted[7] regarding wind generation that wind resources set prices in 33 percent of intervals but usually in very small areas affected by congestion. The locational

[7] Analytic Appendix to the 2012 State of the Market Report for the MISO Electricity Markets; prepared by Potomac Economics, page A-7.

marginal price (LMP) in the small areas were set at an average price of $-16 per MWh. The negative LMP in these small areas is a result of wind resources often bidding negative incremental energy offers because of the US federal production tax credit (PTC) available to wind resources.

An analysis based on MISO hourly price data for the Minnesota Hub (MINN HUB) provided as follows shows that LMPs at the MINN HUB are below $0/ MWh less than 1% of the time. As the LMP when wind was setting the marginal price was found by the IMM to be -$16/ MWh, Manitoba Hydro has concludes that wind is only very rarely setting the LMP at MINN HUB.

Summary of Minn Hub Hourly Prices Below $10 and $0/MWh for 2010-July 2013 *Source: MISO*

MINN HUB	2010	2011	2012	YTD2013
Total # hours DA Price < $0USD	31	55	18	4
# On-Peak hours DA Price < $10USD	0	3	0	0
# Off-Peak hours DA Price < $10USD	412	669	402	82
Total # hours DA Price < $10USD	412	672	402	82
% of all hours DA Price < $0USD	0.35%	0.63%	0.20%	0.07%
% of all hours DA Price < $10USD	4.70%	7.67%	4.58%	1.54%

Further, Manitoba Hydro also notes that despite significantly increased wind generation in MISO since 2010, the number of hours that the MISO Day Ahead price at MINN HUB was negative has declined.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.2.4; Page No.: 45

PREAMBLE: The **Submission claims that coal-fired resources set energy prices in 93% of the intervals (Chapter 5, page 45) and that wind generators set prices only in small transmission-constrained areas (Chapter 5, page 46)**

QUESTION:

Given the relatively lower contributions to electricity generation made by coal in Minnesota and Wisconsin compared to MISO as a whole, do these observations regarding coal setting prices for 93% of the intervals apply to the regional markets that Manitoba Hydro is selling into?

RESPONSE:

The general observations regarding coal setting the marginal price in MISO as a whole are also applicable to Minnesota and Wisconsin.

As noted in response to CAC/MH I-214, MISO does not dispatch generation within a state to meet only the loads within a state. Rather MISO dispatches the entire regional generation fleet to meet the aggregate load of the region, subject to transmission limits, and without regard to state boundaries. Coal generation from out-of-state, particularly from North Dakota, is an important source of electricity supply to Minnesota.

The 2012 IMM report[8] reaffirmed the importance of coal generation in MISO: "Coal remained the most prevalent price-setting fuel in MISO. It was at least one of the marginal fuels (in at

[8] Analytic Appendix for the 2012 State of the Market Report for the MISO Electricity Markets; as prepared by Potomac Economics, page A-7.

least some locations) in 92 percent of all intervals and generated two thirds of all of the energy in 2012."

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.4.2.4; Page No.: 46

PREAMBLE: Manitoba Hydro currently assumes that exports displace (and its imports result in) 0.75 tonnes of CO2 / MWh.

QUESTION:

Is this estimate based on coal being the marginal fuel 93% of the time along with natural gas 23% of the time as per the MISO market overall? If yes, would the value be lower if calculated using the marginal generation characteristics for Minnesota and Wisconsin?

RESPONSE:

The 0.75 tonnes of CO_2/MW.h export GHG emission displacement factor assumed by Manitoba Hydro reflects the displacement of a mixture of fossil-fuel resources and a variety of generation technologies and efficiencies. As stated in ***Chapter 5 – The Manitoba Hydro System Interconnections and Export Markets***, Section 5.4.2.4, coal generation GHG emission are typically on the order of 0.9 to 1.1 tonnes CO_2/MWh while natural gas generation can range from about 0.3 to 0.8 tonnes CO_2/MWh depending on the specific technology and efficiency. As identified in ***Appendix 5.3 – Electricity Market Overview for Manitoba Hydro's Export Market in MISO***, prepared by The Brattle Group, these fossil fuel technologies are virtually always on the margin yielding current emissions displacement within the range of 0.5 to 1.0 tonnes CO_2/MWh and historically coal was marginal nearly all of the time (page 43). Therefore, the assumption of 0.75 tonnes CO_2/MWh export GHG emission displacement factor is currently an appropriate representation of the overall MISO region including Minnesota and Wisconsin. Note that MISO does not dispatch the generation resources of a particular state to serve only the load in that state. Rather MISO dispatches the overall resources of the market to meet the aggregate market load based on the economics of the generation offers.

The MISO Independent Market Monitor's 2011 State of the Market annual report indicates coal was on the margin 93% of all hours in the year while natural gas was the only other significant marginal fuel, on the margin 23% of the time. These specific values are not used in determining the emission displacement factor but simply illustrate that coal is on the margin a substantial portion of the time.

REFERENCE: Appendix 5.3 Electricity Market Overview for Manitoba Hydro's Export Market in MISO; Page No.: 44

PREAMBLE: Appendix 5.3, Slide 44 suggests that long-run CO2 displacement should be based on coal retirements

QUESTION:

Please explain more full why this should be the basis and why CO2 displacement should not be based on avoided new capacity which is likely to be natural gas-fired and will be required if coal is retired (per Slide 53).

RESPONSE:

Calculating displacement based on avoided new generation is often referred to as the "build margin" approach. This approach can provide a simple proxy but is most appropriate when an entity has full control that what is built will be dispatched to meet the majority of the incremental energy needs. This is not the case in a market like MISO where unit dispatch decisions are made by the system operator. Dispatch is based on marginal energy production costs, not on the order they were constructed. For instance, a new natural gas peaker added to the system would operate infrequently (only to meet peak loads), and hence has minimal impact on the average marginal emissions rate. Using an operational margin approach provides the most accurate view of actual GHG emission reductions considering how MISO would respond to additional electricity exports from Manitoba.

Manitoba Hydro assumes a marginal GHG emission displacement factor of 0.75 tonnes CO_2e/MW.h. This reflects the displacement of a mixture of fossil-fuel resources and consists of a variety of technologies and efficiencies. As stated in ***Chapter 5 – The Manitoba Hydro System, Interconnections and Export Markets***, Section 5.4.2.4, coal generation GHG emission are typically on the order of 0.9 to 1.1 tonnes CO_2/MW.h while natural gas generation can range

from about 0.3 to 0.8 tonnes CO_2/MW.h depending on the specific technology and efficiency. Because coal is on the margin a substantial portion of the time, the assumption of 0.75 tonnes CO_2/MW.h is an appropriate representation of the current GHG emission displacements associated with Manitoba Hydro's net exports. As identified in ***Appendix 5.3 – Electricity Market Overview for Manitoba Hydro's Export Market in MISO***, prepared by The Brattle Group, these fossil fuel technologies are virtually always on the margin yielding current emissions displacement within the range of 0.5 to 1.0 tonnes CO_2/MW.h and historically coal was marginal nearly all the time (page 43).

REFERENCE: Appendix 5.3 Electricity Market Overview for Manitoba Hydro's Export Market in MISO; Page No.: 56

PREAMBLE: Appendix 5.3, Slide 55 indicates that Indiana has a voluntary goal.

QUESTION:

Please confirm that Indiana has an opt-in provision such that if a utility opts-in the RPS is mandatory and it if does not opt-in then the RPS does not apply. Please also confirm that to date no Indiana utility has opted-in.

RESPONSE:

Indiana's Clean Energy Portfolio is a voluntary program. Manitoba Hydro is not in a position to confirm whether any Indiana utilities have opted-in as of yet.

REFERENCE: Chapter 5: The Manitoba Hydro System Interconnections and Export Markets; Section: 5.6.2; Page No.: 61

QUESTION:

Please confirm that the Fermi nuclear plant is located in Michigan (not Ohio). Please indicate whether it is within the MISO market footprint.

RESPONSE:

According to U.S. Nuclear Regulatory Commission (NRC) data, the Fermi unit is located in Newport, MI, some 25 miles north east of Toledo, OH. The Fermi unit is listed as being a MISO nuclear plant.

REFERENCE: Executive Summary; Page No.: 2

PREAMBLE: "The concern of the NFAT review is not the long term sustainable provisioning of electricity in Manitoba. The review is fundamentally about how best to ensure that the electrical energy system, including generation, delivery and use, provides lasting maximum social, economic and biophysical benefits, while avoiding adverse effects. . Electricity is simply a means to social ends. As energy strategy experts have observed many times, people do not want energy, but rather the services provided by energy – comfortable homes, personal transportation, entertainment, etc. (Lovins 1977; Science Council of Canada 1977; Bott et al. 1983; Brooks and Newman 2004). This understanding is evident in Manitoba's Energy Act, especially in the specifics of obligations associated with the principles of sustainable development (s.3). It seems also to be recognized in Manitoba Hydro's in the NFAT filing statement that it (Manitoba Hydro 2013, Executive Summary p.2): "has been created, and its activities governed, by The Manitoba Hydro Act. According to the Act, the purpose of Manitoba Hydro is to "provide for the continuance of a supply of power adequate for the needs of the province, and to engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and end-use of power"" (emphasis added). Likewise, in the Manitoba Clean Energy Strategy (Manitoba 2012, p.6) notes that one of its Strategic Objectives is to "ensure that energy is used efficiently, for environmental and economic reasons." Finally, the Terms of Reference for the NFAT (Manitoba 2013, p.2-3) require an assessment of the socio-economic impacts and benefits of the Plan and alternatives to northern and aboriginal communities", where socio-economic impacts have been defined by the Public Utilities Board as being (PUB 2013, p.14): A critical analysis of the socio-economic impacts and benefits of Manitoba Hydro's Preferred Development Plan and alternative Plans. Specifically, a high level summary of potential effects to people in Manitoba, especially Northern and Aboriginal communities, including such things as employment, training and business opportunities; infrastructure and services; personal family and community life; and resource use. " All of these requirements make it clear that beyond simply discussing the provisioning of electricity in Manitoba, it is important for Manitoba Hydro to consider the extent to which the electricity is to be used, as well as generated and delivered, for constructive ends. Unfortunately, there does not appear to be any such discussion provided in the NFAT, which focuses instead on a set of forecasted energy demands with no analysis of whether meeting all of these demands would be consistent with the broader strategic objectives and review scope noted above. Ultimately, the question before the review is whether the conclusions of Manitoba Hydro's comparative evaluation of alternatives identify best means of moving towards and serving a desirable future, with positive socio-economic and biophysical effects. References Bott, R., et al. (1983). Life after oil :

a renewable energy policy for Canada. Edmonton, Hurtig. Brooks, D., B. and L. Newman (2004). ""The soft path holds up- Efficient technologies and renewable sources will bring a cheaper, more reliable energy future."" Alternatives 30(1): 7. Lovins, A. B. (1977). Soft energy paths: towards a durable peace. San Fransisco, Friends of the Earth. Manitoba (2012). Manitoba Clean Energy Strategy. E. a. M. Ministry of Innovation. Manitoba (2013). Terms of Reference - Needs For and Alternatives To (NFAT Review, Government of Manitoba. Manitoba Hydro (2013). NFAT (Needs For and Alternatives To) Business Case Submission Manitoba Hydro. PUB (2013). Manitoba - The Public Utilities Board Act - Order 92/13. T. M. P. U. Board. Science Council of Canada (1977). Canada as a conserver society : resource uncertainties and the need for new technologies. Ottawa"

QUESTION:

"Please provide an analysis of the desirability of the forecasted end-uses of electricity, and how these end-users may lead to positive socio-economic outcomes while avoiding adverse effect. "

RESPONSE:

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

REFERENCE: Executive Summary; Page No.: 2

PREAMBLE: The concern of the NFAT review is not the long term sustainable provisioning of electricity in Manitoba. The review is fundamentally about how best to ensure that the electrical energy system, including generation, delivery and use, provides lasting maximum social, economic and biophysical benefits, while avoiding adverse effects. Electricity is simply a means to social ends. As energy strategy experts have observed many times, people do not want energy, but rather the services provided by energy – comfortable homes, personal transportation, entertainment, etc. (Lovins 1977; Science Council of Canada 1977; Bott et al. 1983; Brooks and Newman 2004).

This understanding is evident in Manitoba's Energy Act, especially in the specifics of obligations associated with the principles of sustainable development (s.3). It seems also to be recognized in Manitoba Hydro's in the NFAT filing statement that it (Manitoba Hydro 2013, Executive Summary p.2):

"has been created, and its activities governed, by The Manitoba Hydro Act. According to the Act, the purpose of Manitoba Hydro is to "provide for the continuance of a supply of power adequate for the needs of the province, and to engage in and to promote economy and efficiency in the development, generation, transmission, distribution, supply and **end-use of power**"" (emphasis added).

Likewise, in the Manitoba Clean Energy Strategy (Manitoba 2012, p.6) notes that one of its Strategic Objectives is to "ensure that energy is used efficiently, for environmental and economic reasons."

Finally, the Terms of Reference for the NFAT (Manitoba 2013, p.2-3) require an assessment of the "socio-economic impacts and benefits of the Plan and alternatives to northern and aboriginal communities", where socio-economic impacts have been defined by the Public Utilities Board as being (PUB 2013, p.14):

"A critical analysis of the socio-economic impacts and benefits of Manitoba Hydro's Preferred Development Plan and alternative Plans. Specifically, a high level summary of potential effects to people in Manitoba, especially Northern and Aboriginal communities, including such things as employment, training and business opportunities; infrastructure and services; personal family and community life; and resource use."

All of these requirements make it clear that beyond simply discussing the provisioning of electricity in Manitoba, it is important for Manitoba Hydro to consider the extent to which the electricity is to be used, as well as generated and delivered, for constructive ends. Unfortunately, there does not appear to be any such discussion provided in the NFAT, which focuses instead on a set of forecasted energy demands with no analysis of whether meeting all of these demands would be consistent with the broader strategic objectives and review scope noted above. Ultimately, the question before the review is whether the conclusions of Manitoba Hydro's comparative evaluation of alternatives identify best means of moving towards and serving a desirable future, with positive socio-economic and biophysical effects.

References

Bott, R., et al. (1983). Life after oil : a renewable energy policy for Canada. Edmonton, Hurtig.

Brooks, D., B. and L. Newman (2004). "The soft path holds up- Efficient technologies and renewable sources will bring a cheaper, more reliable energy future." Alternatives 30(1): 7.

Lovins, A. B. (1977). Soft energy paths: towards a durable peace. San Fransisco, Friends of the Earth.

Manitoba (2012). Manitoba Clean Energy Strategy. E. a. M. Ministry of Innovation.

Manitoba (2013). Terms of Reference - Needs For and Alternatives To (NFAT Review, Government of Manitoba.

Manitoba Hydro (2013). NFAT (Needs For and Alternatives To) Business Case Submission Manitoba Hydro.

PUB (2013). Manitoba - The Public Utilities Board Act - Order 92/13. T. M. P. U. Board.

Science Council of Canada (1977). Canada as a conserver society: resource uncertainties and the need for new technologies. Ottawa

QUESTION:

Please discuss the extent to which Manitoba Hydro has begun its analysis with the consideration of desirable futures and associated end-uses and then backcasts to the determination of how those end-uses may be met.

RESPONSE:

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

REFERENCE: Executive Summary; Page No.: 10

PREAMBLE: In the Executive Summary of the NFAT, Manitoba Hydro notes (Manitoba Hydro 2013, Executive Summary p.10):

"To determine Manitoba's electricity supply need, Manitoba Hydro regularly assesses domestic demand (load growth net of reductions resulting from DSM) and firm export commitments to arrive at total demand. Total demand is then compared to current supply. Total demand is currently projected to exceed existing supply beginning around 2023 even with no new export commitments. **The need for new supply to meet Manitoba domestic load is the principal driver of the Preferred Development Plan**" (emphasis added).

Despite Manitoba Hydro's claim that domestic consumption is the principal driver of the Preferred Development Plan, the NFAT document appears to present the preferred development plan (with its focus on two large hydro projects and significant construction of international transmission lines) as geared towards exporting electricity. It is not clear from the Manitoba Hydro NFAT submission that even a single new hydro dam is needed to meet forecasted demands, once serious consideration of alternatives (including biomass heating, wind power and expanded DSM) are considered.

QUESTION:

Please clarify how the construction of two new hydro dams represents an approach guided principally by needs to meet the anticipated domestic load.

RESPONSE:

The NFAT studies show conclusively that a plan comprised mainly of new hydro is a more economic means to supply Manitoba domestic load growth than one which is comprised mainly of new gas generation. (Chapters 9, 10 & 14). Biomass and wind were eliminated as primary options during the screening and probabilistic analysis because of poor economics.

The hydro plan is more economic than a gas plan including in sensitivities with a 10th percentile low load growth. This sensitivity can be taken as being representative of a very low load growth scenario or a scenario with DSM greater than 4 times the 2012 DSM level or some combination of lower load growth and higher DSM.

The studies also show conclusively that the Keeyask and interconnection plans are more economic to meet domestic load growth than the gas plan or other plans which include no new interconnections.

The interconnection plans with Conawapa in addition to Keeyask are shown generally to be more economic to meet domestic load growth than the gas plan or other plans with no new interconnection. However, as discussed extensively in the submission, no construction commitment is being made to Conawapa at this time. Should it become evident in future that it would not be overall beneficial for domestic load growth to be met with Conawapa following Keeyask, Conawapa can be deferred or cancelled up to 2018 assuming a Conawapa 2026 ISD.

REFERENCE: Executive Summary; Page No.: 2

PREAMBLE: One area of electricity production and consumption that shows tremendous promise is that relating to conservation and demand side management. For example, the Manitoba Clean Energy Strategy highlights its goal of "Leading Canada in Energy Efficiency" through such outcomes as (Manitoba 2012, p.3): • "Through Manitoba Hydro, implement a new on-Meter financing program that overcomes the high upfront costs that prevent households from implementing energy saving retrofit measures. • Enhance Manitoba's successful Low Income energy efficiency programming, in partnership with social enterprises, to help build community capacity, create jobs and maximize economic benefits. • Expand The Green Building Policy so that more government funded building construction, renovation and operations are subject to energy efficiency requirements. • Expedite adoption of National Building Code energy efficiency updates to ensure Manitoba homes and businesses achieve the lowest lifetime costs for energy. • Advance vehicle-related efficiency through green fleet purchasing policies, support for higher vehicle fuel efficiency standards and promotion of active transportation. • Support the expansion of voluntary programs to benchmark, rate and label building energy performance. Manitoba will explore and pilot programs that disclose the energy performance of buildings offered for sale or lease. • Pursue minimum energy efficiency standards for high-energy consuming products where federal standards are deemed inadequate. • Develop and publish an annual energy efficiency plan that establishes stronger efficiency targets; identifies an expanded range of programming options; sets out costs and benefits; and reports on performance." In the NFAT filing, Manitoba Hydro recognizes the importance of conservation and demand side management when it notes (Manitoba Hydro 2013, Executive Summary p.2): "In addition to the above major components, the Preferred Development Plan includes continued substantial investment in DSM/Power Smart and efficiency improvements to existing generation." While this promotion of conservation and demand side management is noteworthy, the NFAT appears to provide very little information relating to what "continued substantial investment in DSM/Power Smart" in fact entails.

QUESTION:

Please define what "substantial investment in DSM/Power Smart and efficiency improvements to existing generation" entails, with attention to what DSM/Power Smart and efficiency improvement initiatives are included (assumed) in the preferred option, which potential

DSM/Power Smart and efficiency improvement initiatives were considered but not included, and the rationale for those decisions.

RESPONSE:

As outlined in Chapter 4, Manitoba Hydro's future DSM strategy involves an additional investment of $326 million (2012$) with expected energy savings of 1,552 GWh/year and 490 MW expected to be captured by 2027/28. Combined with energy savings achieved to date, total electrical savings of 3,113 GWh and 846 MW will be realized by 2027/28, with a cumulative investment of $762 million (2012$). The DSM/Power Smart initiatives included within the Preferred Development Plan are outlined in the 2013 – 2016 Power Smart Plan included as Appendix E to this submission.

On page 28 of Chapter 4, it is noted that Manitoba Hydro's DSM Plan includes those technology initiatives identified as being available and economic today. Recently, Manitoba Hydro approved a community-based residential geothermal program, which will be included in the next update of the Corporation's Power Smart Plan. In addition, Manitoba Hydro is assessing a number of additional initiatives and program strategies which may be included in future DSM plans. Initiatives currently being investigated include, but are not limited to, a new home program, residential LED lighting program, LED roadway lighting conversion program, along with expansion of industrial performance optimization programs and load displacement programs.

Manitoba Hydro generally updates its Power Smart plan annually, and as outlined on page 32 of Chapter 4 of this submission, the Corporation's Power Smart Plan is intended to be updated by March 31, 2014. The recently completed Market Potential Study results will aid in the process of updating the Power Smart Plan. The updated plan will be prepared in consultation with the

Minister of Innovation, Energy and Mines responsible for Manitoba Hydro as directed in The Manitoba Energy Savings Act.

Please refer to page 26 of Chapter 4 for a select, but not exhaustive, list of technologies that have been assessed but are not being pursued at this time and the supporting rationale. In addition, please also refer to Manitoba Hydro's response to CAC-GAC/MH I-0005(a).

Manitoba Hydro takes advantage of supply-side enhancement opportunities by continually monitoring the condition of its existing generating facilities and assessing the most cost effective way of maintaining operations while optimizing the generating capability of these facilities. Please refer to page 43 of Chapter 4 for a description of some of these projects. In addition, please also refer to Manitoba Hydro's response to CAC/MH I-0063.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Page No.: 13

PREAMBLE: The tremendous promise of conservation and demand side management is recognized, for example in the Manitoba Clean Energy Strategy, which highlights its active approach to "Leading Canada in Energy Efficiency" through such outcomes as (Manitoba 2012, p.3):

• "Through Manitoba Hydro, implement a new on-Meter financing program that overcomes the high upfront costs that prevent households from implementing energy saving retrofit measures.

• Enhance Manitoba's successful Low Income energy efficiency programming, in partnership with social enterprises, to help build community capacity, create jobs and maximize economic benefits.

• Expand the Green Building Policy so that more government funded building construction, renovation and operations are subject to energy efficiency requirements.

• Expedite adoption of National Building Code energy efficiency updates to ensure Manitoba homes and businesses achieve the lowest lifetime costs for energy.

• Advance vehicle-related efficiency through green fleet purchasing policies, support for higher vehicle fuel efficiency standards and promotion of active transportation.

• Support the expansion of voluntary programs to benchmark, rate and label building energy performance. Manitoba will explore and pilot programs that disclose the energy performance of buildings offered for sale or lease.

• Pursue minimum energy efficiency standards for high-energy consuming products where federal standards are deemed inadequate.

• Develop and publish an annual energy efficiency plan that establishes stronger efficiency targets; identifies an expanded range of programming options; sets out costs and benefits; and reports on performance."

Unfortunately, in the Manitoba Hydro NFAT submission itself, as well as in the appendices (e.g. Appendix 4.3 - Demand Side Management Potential Study), there appears to be no description by Manitoba Hydro of how it, as a crown corporation, could collaborate with the provincial government to stimulate the market for DSM opportunities and foster social and technological innovation. Instead, Manitoba Hydro notes that (Manitoba Hydro 2013, C.7 p.13):

"One of the main considerations with DSM is that, **without regulation or legislation**, achieving energy reduction targets is strongly dependent upon market acceptance and

voluntary action. Also, in addition to market availability and adoption forecasts, the savings potential is estimated based on a variety of assumptions that include natural technological development, anticipated customer energy usage/savings and market cost projections. As a result, expected energy savings from DSM do not have the same future certainty of supply as would the development of a physical resource" (emphasis added).

QUESTION:

Please describe the research undertaken by Manitoba Hydro (or its consultants) to determine the potential for fostering social and technological innovation in the area of conservation and demand management.

RESPONSE:

Manitoba Hydro undertakes research in areas central to its core business including Conservation and Demand Side Management. The objective of this research is to enhance the Corporation's understanding of innovate concepts and ideas with potential to advance Manitoba Hydro core business activities and promote the advancement of such innovations.

In keeping with these objectives, Manitoba Hydro collaborates in and co-funds a broad cross-section of innovative research. A selection of Manitoba Hydro's recent technological research activities relevant to innovation in the areas of conservation and demand side management includes the following:

- Energy Performance Benchmarking Models for Refrigerated Warehouses
- Large Commercial Building Air Leakage Testing
- Urban Energy Density Mapping
- Solar Thermal Trough Demonstration Relevant to Cold Climate at Red River College
- Solar Greenhouses for Northern Manitoba
- Canadian Electric Vehicle Infrastructure Deployment Guideline
- All-Electric Transit Bus Development and Demonstration

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Page No.: 13

PREAMBLE: The tremendous promise of conservation and demand side management is recognized, for example in the Manitoba Clean Energy Strategy, which highlights its active approach to "Leading Canada in Energy Efficiency" through such outcomes as (Manitoba 2012, p.3):

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"One of the main considerations with DSM is that, **without regulation or legislation**, achieving energy reduction targets is strongly dependent upon market acceptance and

voluntary action. Also, in addition to market availability and adoption forecasts, the savings potential is estimated based on a variety of assumptions that include natural technological development, anticipated customer energy usage/savings and market cost projections. As a result, expected energy savings from DSM do not have the same future certainty of supply as would the development of a physical resource" (emphasis added).

QUESTION:

Please identify and provide a preliminary analysis of the potential and implications of DSM options that could be undertaken by the provincial government or by Manitoba Hydro in collaboration with the provincial government.

RESPONSE:

As part of the Corporation's ongoing efforts to achieve energy savings, Manitoba Hydro has ongoing dialogue and discussion with the Provincial Government and various governmental departments and agencies regarding energy efficiency and potential opportunities to expand those efforts in Manitoba. Through this discussion and interaction with the Province and other stakeholders, Manitoba Hydro is actively pursuing the outcomes noted in the preamble. Manitoba Hydro's involvement is with provincial and federal governments, work with standards organizations and other standards proponents.

Examples of initiatives involving both Manitoba Hydro and external government bodies include:

- Manitoba Hydro is working closely with the Office of the Fire Commissioner to implement improvements in the energy performance requirements for commercial and residential building codes; a key ingredient to improved energy efficiency in a heating dominant climate such as Manitoba. Manitoba Hydro's Commercial Building Programs provide for labeling opportunities that are compatible with other recognized labeling programs such as LEED.
- Manitoba Hydro is working with other stakeholders to lead in securing energy savings achieved through voluntary and regulatory standards applied to energy consuming

equipment, buildings and processes. Many of these standards impact the design and performance of energy consuming products manufactured outside of Manitoba and for which are produced for a much broader North American-based market. Manitoba Hydro's efforts are often focused on initiatives that provide perspective and application across provincial and national boundaries, expanding the influence and reach of these efforts in a manner that has a powerful influence on the overall sustainability and certainty of energy savings achieved when customers in Manitoba purchase energy consuming appliances and equipment.

- Manitoba Hydro has further worked with the Province to implement both a residential and commercial PAYS program that provides low interest rate financing for energy efficiency improvements that is repaid through the energy savings achieved by these improvements. This initiative is intended to expand the capture of energy efficiency savings by addressing key barriers associated with the availability of capital and concern over owning the building long enough to realize a positive payback.
- Manitoba Hydro, the provincial government and others are working together to develop an all-electric transit bus. This example involves working with both government and the private sector, to provide leading edge made-in-Manitoba solutions that provide benefits not only within Manitoba but across the continent. The technology and expertise developed through this effort will be applicable to many types of heavy vehicles used in utility and other applications.
- In partnership with the Province, Manitoba Hydro was active in supporting and developing the Green Building Policy. Many aspects of this policy relied on the work undertaken by Manitoba Hydro to establish performance standards for government-funded buildings which were relevant to Manitoba's environment.
- The Provincial government is planning to ban the use of coal for space and water heating in 2017, forcing coal users to examine alternative energy sources for their space and water heating needs. Under the plan, coal users are expected to file transition plans detailing the process they will be implementing to transition to alternate energy sources. Manitoba Hydro is working closely with coal users from across the Province to

assist them in evaluating their energy choices, examining options for geothermal and biomass alternatives, along with more conventional electric and natural gas options.

REFERENCE: Chapter 4: The Need for New Resources; Page No.: p.25-26

PREAMBLE: Both the NFAT filing and the Manitoba Clean Energy Strategy highlight Manitoba's comment to conservation and demand side management programs. For example, Manitoba Hydro notes it is (Manitoba Hydro 2013, C.4 p.18) "committed to DSM with a focus on pursuing all cost-effective energy efficiency opportunities and continually monitoring the market for emerging trends and opportunities, which may become economically viable." Likewise, in the Executive Summary (p.11), Manitoba Hydro notes its: "DSM strategy for the future involves a long-term commitment to pursuing all energy efficient opportunities which have been identified as being economically viable in Manitoba." To this end, the Manitoba Clean Energy Strategy (p.19) describes the successes of DSM by noting: "These efficiency savings have cost Manitoba hydro, on average, just 1.9 ¢/kWh (kilowatt hour), well below the cost of other methods. This saved energy is then resold on the export market by Manitoba Hydro, earning profits and helping keep domestic rates down." Despite the importance given to conservation and demand management, the NFAT filing notes Manitoba Hydro will only "pursue all those DSM opportunities with a levelized resource cost less than the corporation's marginal cost value" (Manitoba Hydro 2013, C.4 p.25-26). Manitoba Hydro justifies this approach as follows (Manitoba Hydro 2013, C.4 p.25): "As each DSM opportunity is an independent decision, Manitoba Hydro assesses the economics of pursuing each energy efficiency opportunity individually. This approach is consistent with assessing each supply-side option on its own merits." This approach severely limits the potential for conservation and demand side management initiatives, and appears to be inconsistent with assessing supply side options on their own individual merits. A more equitable and strategic approach to DSM would be to develop a suite of DSM opportunities whose average costs are equal to the corporation's marginal cost value. Such an approach could serve to stimulate DSM opportunities that are not yet individually cost efficient, all the while providing (or in this case conserving) electricity at a comparable rate and oftentimes without the negative socio-economic and macro-environmental costs of other forms of generation (such as the flooding of vast tracts of land for hydro-electricity).

QUESTION:

Please provide a preliminary analysis of:

(i) what DSM/Power Smart and efficiency improvement initiatives could be included in a package that as a whole could have an average cost equal to the corporation's marginal cost value

RESPONSE:

In Order 119/13 the PUB determined that this Information Request need not be answered.

REFERENCE: Chapter 4: The Need for New Resources; Page No.: p.25-26

PREAMBLE: Both the NFAT filing and the Manitoba Clean Energy Strategy highlight Manitoba's comment to conservation and demand side management programs. For example, Manitoba Hydro notes it is (Manitoba Hydro 2013, C.4 p.18) "committed to DSM with a focus on pursuing all cost-effective energy efficiency opportunities and continually monitoring the market for emerging trends and opportunities, which may become economically viable." Likewise, in the Executive Summary (p.11), Manitoba Hydro notes its: "DSM strategy for the future involves a long-term commitment to pursuing all energy efficient opportunities which have been identified as being economically viable in Manitoba." To this end, the Manitoba Clean Energy Strategy (p.19) describes the successes of DSM by noting: "These efficiency savings have cost Manitoba hydro, on average, just 1.9 ¢/kWh (kilowatt hour), well below the cost of other methods. This saved energy is then resold on the export market by Manitoba Hydro, earning profits and helping keep domestic rates down." Despite the importance given to conservation and demand management, the NFAT filing notes Manitoba Hydro will only "pursue all those DSM opportunities with a levelized resource cost less than the corporation's marginal cost value" (Manitoba Hydro 2013, C.4 p.25-26). Manitoba Hydro justifies this approach as follows (Manitoba Hydro 2013, C.4 p.25): "As each DSM opportunity is an independent decision, Manitoba Hydro assesses the economics of pursuing each energy efficiency opportunity individually. This approach is consistent with assessing each supply-side option on its own merits." This approach severely limits the potential for conservation and demand side management initiatives, and appears to be inconsistent with assessing supply side options on their own individual merits. A more equitable and strategic approach to DSM would be to develop a suite of DSM opportunities whose average costs are equal to the corporation's marginal cost value. Such an approach could serve to stimulate DSM opportunities that are not yet individually cost efficient, all the while providing (or in this case conserving) electricity at a comparable rate and oftentimes without the negative socio-economic and macro-environmental costs of other forms of generation (such as the flooding of vast tracts of land for hydro-electricity).

QUESTION:

Please provide a preliminary analysis of what demand reduction could reasonably be anticipated;

RESPONSE:

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

REFERENCE: Chapter 4: The Need for New Resources; Page No.: p.25-26

PREAMBLE: Both the NFAT filing and the Manitoba Clean Energy Strategy highlight Manitoba's comment to conservation and demand side management programs. For example, Manitoba Hydro notes it is (Manitoba Hydro 2013, C.4 p.18) "committed to DSM with a focus on pursuing all cost-effective energy efficiency opportunities and continually monitoring the market for emerging trends and opportunities, which may become economically viable." Likewise, in the Executive Summary (p.11), Manitoba Hydro notes its: "DSM strategy for the future involves a long-term commitment to pursuing all energy efficient opportunities which have been identified as being economically viable in Manitoba." To this end, the Manitoba Clean Energy Strategy (p.19) describes the successes of DSM by noting: "These efficiency savings have cost Manitoba hydro, on average, just 1.9 ¢/kWh (kilowatt hour), well below the cost of other methods. This saved energy is then resold on the export market by Manitoba Hydro, earning profits and helping keep domestic rates down." Despite the importance given to conservation and demand management, the NFAT filing notes Manitoba Hydro will only "pursue all those DSM opportunities with a levelized resource cost less than the corporation's marginal cost value" (Manitoba Hydro 2013, C.4 p.25-26). Manitoba Hydro justifies this approach as follows (Manitoba Hydro 2013, C.4 p.25): "As each DSM opportunity is an independent decision, Manitoba Hydro assesses the economics of pursuing each energy efficiency opportunity individually. This approach is consistent with assessing each supply-side option on its own merits." This approach severely limits the potential for conservation and demand side management initiatives, and appears to be inconsistent with assessing supply side options on their own individual merits. A more equitable and strategic approach to DSM would be to develop a suite of DSM opportunities whose average costs are equal to the corporation's marginal cost value. Such an approach could serve to stimulate DSM opportunities that are not yet individually cost efficient, all the while providing (or in this case conserving) electricity at a comparable rate and oftentimes without the negative socio-economic and macro-environmental costs of other forms of generation (such as the flooding of vast tracts of land for hydro-electricity).

QUESTION:

Please provide a preliminary analysis of how such an approach may promote technological and social innovation in Manitoba

RESPONSE:

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

REFERENCE: Chapter 4: The Need for New Resources; Page No.: p.25-27

PREAMBLE: Both the NFAT filing and the Manitoba Clean Energy Strategy highlight Manitoba's comment to conservation and demand side management programs. For example, Manitoba Hydro notes it is (Manitoba Hydro 2013, C.4 p.18) "committed to DSM with a focus on pursuing all cost-effective energy efficiency opportunities and continually monitoring the market for emerging trends and opportunities, which may become economically viable." Likewise, in the Executive Summary (p.11), Manitoba Hydro notes its: "DSM strategy for the future involves a long-term commitment to pursuing all energy efficient opportunities which have been identified as being economically viable in Manitoba." To this end, the Manitoba Clean Energy Strategy (p.19) describes the successes of DSM by noting: "These efficiency savings have cost Manitoba hydro, on average, just 1.9 ¢/kWh (kilowatt hour), well below the cost of other methods. This saved energy is then resold on the export market by Manitoba Hydro, earning profits and helping keep domestic rates down." Despite the importance given to conservation and demand management, the NFAT filing notes Manitoba Hydro will only "pursue all those DSM opportunities with a levelized resource cost less than the corporation's marginal cost value" (Manitoba Hydro 2013, C.4 p.25-26). Manitoba Hydro justifies this approach as follows (Manitoba Hydro 2013, C.4 p.25): "As each DSM opportunity is an independent decision, Manitoba Hydro assesses the economics of pursuing each energy efficiency opportunity individually. This approach is consistent with assessing each supply-side option on its own merits." This approach severely limits the potential for conservation and demand side management initiatives, and appears to be inconsistent with assessing supply side options on their own individual merits. A more equitable and strategic approach to DSM would be to develop a suite of DSM opportunities whose average costs are equal to the corporation's marginal cost value. Such an approach could serve to stimulate DSM opportunities that are not yet individually cost efficient, all the while providing (or in this case conserving) electricity at a comparable rate and oftentimes without the negative socio-economic and macro-environmental costs of other forms of generation (such as the flooding of vast tracts of land for hydro-electricity).

QUESTION:

Please provide a preliminary analysis of what implications that would have for the need for the proposed generation and transmission projects.

RESPONSE:

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

REFERENCE: Chapter 4: The Need for New Resources.

PREAMBLE: Both the NFAT filing and the Manitoba Clean Energy Strategy highlight Manitoba's comment to conservation and demand side management programs. For example, Manitoba Hydro notes it is (Manitoba Hydro 2013, C.4 p.18) "committed to DSM with a focus on pursuing all cost-effective energy efficiency opportunities and continually monitoring the market for emerging trends and opportunities, which may become economically viable." Likewise, in the Executive Summary (p.11), Manitoba Hydro notes its: "DSM strategy for the future involves a long-term commitment to pursuing all energy efficient opportunities which have been identified as being economically viable in Manitoba." To this end, the Manitoba Clean Energy Strategy (p.19) describes the successes of DSM by noting: "These efficiency savings have cost Manitoba hydro, on average, just 1.9 ¢/kWh (kilowatt hour), well below the cost of other methods. This saved energy is then resold on the export market by Manitoba Hydro, earning profits and helping keep domestic rates down." Despite the importance given to conservation and demand management, the NFAT filing notes Manitoba Hydro will only "pursue all those DSM opportunities with a levelized resource cost less than the corporation's marginal cost value" (Manitoba Hydro 2013, C.4 p.25-26). Manitoba Hydro justifies this approach as follows (Manitoba Hydro 2013, C.4 p.25): "As each DSM opportunity is an independent decision, Manitoba Hydro assesses the economics of pursuing each energy efficiency opportunity individually. This approach is consistent with assessing each supply-side option on its own merits." This approach severely limits the potential for conservation and demand side management initiatives, and appears to be inconsistent with assessing supply side options on their own individual merits. A more equitable and strategic approach to DSM would be to develop a suite of DSM opportunities whose average costs are equal to the corporation's marginal cost value. Such an approach could serve to stimulate DSM opportunities that are not yet individually cost efficient, all the while providing (or in this case conserving) electricity at a comparable rate and oftentimes without the negative socio-economic and macro-environmental costs of other forms of generation (such as the flooding of vast tracts of land for hydro-electricity).

QUESTION:

Please provide a second version of the preliminary analysis outlined above, with adjustments to incorporate consideration of the main socio-economic and macro-environmental costs/risks

and benefits not otherwise captured in evaluations limited to the marginal cost value calculations.

RESPONSE:

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

REFERENCE: Chapter 14: Conclusions; Page No.: Page 3 (Ch. 14) and 24 (App 14.1)

PREAMBLE: In a few instances in the NFAT, Manitoba Hydro acknowledges that its approach to conservation and demand side management is incomplete. For example, in Chapter 14, Manitoba Hydro notes it will (Manitoba Hydro 2013, C.14 p.3) "update its Power Smart Plan, in consultation with government as required by The Energy Savings Act, by March 31, 2014, which will incorporate the information contained in the DSM Market Potential Study. In the process of updating the DSM plan, Manitoba Hydro will evaluate the possibility of a higher level of DSM. … The updated Power Smart plan will be included in future Power Resource Plans as part of whichever development plan and pathway is pursued by Manitoba Hydro at the conclusion of the NFAT process." To justify the incomplete assessment of DSM, Manitoba Hydro notes in Appendix 14.1 that (Manitoba Hydro 2013, App 14.1 p.24) "Manitoba Hydro's preferred plan also accommodates DSM (i.e. Power Smart programs). Although DSM is not included per se in the preferred plan, economic evaluation sensitivities indicate that increasing DSM significantly increases the attractiveness of the preferred plan. As such, it was not necessary in the NFAT submission to further include different levels of DSM in the detailed evaluations of the different plans to be able to assess the attractiveness of the plans." There are two concerns with this approach. First, it is not immediately clear that increasing DSM will increase the attractiveness of the preferred plan in all instances. Second, what is not clear from the NFAT discussions of DSM is the impact of the significant increase in electricity production in the preferred plan upon the desirability and feasibility of DSM. In other words, there is a risk that significantly expanding electricity production will have negative effects on future motivations to push DSM innovation. It is important to have explicit analysis to show that increasing supply options won't negatively impact effort to enhance the efficient use of energy.

QUESTION:

"Please provide the economic evaluation sensitivities that indicate that increasing DSM significantly increases the attractiveness of the preferred plan. "

RESPONSE:

The economic evaluation of DSM sensitivities is presented in ***Chapter 12 – Economic Evaluations - 2013*** Update ***on Selected Development Plans Section 12.2 Demand Side Management Sensitivity and Stress Test.***

The DSM sensitivity and stress test indicated that in general the development plans analyzed benefit from increased levels of DSM. The Preferred Plan and Plan 4 (K19/Gas30/250MW) derive greater benefits from higher levels of DSM than the K23/Gas plan.

Both the Preferred Plan and Plan 4 benefit similarly at the 1.5 times DSM level. At the 4.0 times DSM level Plan 4 can derive more benefit from the higher level of DSM than the Preferred Plan.

REFERENCE: Chapter 14: Conclusions; Page No.: Page 3 (Ch. 14) and 24 (App 14.1)

PREAMBLE: In a few instances in the NFAT, Manitoba Hydro acknowledges that its approach to conservation and demand side management is incomplete. For example, in Chapter 14, Manitoba Hydro notes it will (Manitoba Hydro 2013, C.14 p.3) "update its Power Smart Plan, in consultation with government as required by The Energy Savings Act, by March 31, 2014, which will incorporate the information contained in the DSM Market Potential Study. In the process of updating the DSM plan, Manitoba Hydro will evaluate the possibility of a higher level of DSM. … The updated Power Smart plan will be included in future Power Resource Plans as part of whichever development plan and pathway is pursued by Manitoba Hydro at the conclusion of the NFAT process." To justify the incomplete assessment of DSM, Manitoba Hydro notes in Appendix 14.1 that (Manitoba Hydro 2013, App 14.1 p.24) "Manitoba Hydro's preferred plan also accommodates DSM (i.e. Power Smart programs). Although DSM is not included per se in the preferred plan, economic evaluation sensitivities indicate that increasing DSM significantly increases the attractiveness of the preferred plan. As such, it was not necessary in the NFAT submission to further include different levels of DSM in the detailed evaluations of the different plans to be able to assess the attractiveness of the plans." There are two concerns with this approach. First, it is not immediately clear that increasing DSM will increase the attractiveness of the preferred plan in all instances. Second, what is not clear from the NFAT discussions of DSM is the impact of the significant increase in electricity production in the preferred plan upon the desirability and feasibility of DSM. In other words, there is a risk that significantly expanding electricity production will have negative effects on future motivations to push DSM innovation. It is important to have explicit analysis to show that increasing supply options won't negatively impact effort to enhance the efficient use of energy.

QUESTION:

Please provide an evaluation of the negative and positive effects that the proposed commitment to increased supply side options may have on the attractiveness and potential for future DSM.

RESPONSE:

Please refer to Chapter 12 Section 12.4 of the NFAT Business Case which provides an evaluation of the relative impact of increased levels of DSM on select development plan. One of the conclusions of the evaluations is that, in general, the development plans which were analyzed benefit from increased levels of DSM.

As noted in Chapter 14, Manitoba Hydro will update its Power Smart Plan in consultation with the government as required by The Energy Savings Act by March 31, 2014, which will incorporate the information contained in the DSM Market Potential Study. In the process of updating the DSM plan, Manitoba Hydro will evaluate the possibility of a higher level of DSM. At this time, Manitoba Hydro does not have enough information to measure the economics/incentive of increases in DSM levels for any plans since the costs associated with higher levels of DSM are not yet available.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Page No.: p.12

PREAMBLE: In the Manitoba Clean Energy Strategy, the Government of Manitoba notes the value of non-electric heating systems. For example, page 30 of the Clean Energy Strategy notes (Manitoba 2012, p.30) "Historically, electric heat was the main alternative for those Manitobans who needed a stably-priced alternative to natural gas. As a result, 130,000 families use all electric heat (especially in rural areas and apartments) today and 230,000 use electric hot water. Even so, using electricity – a high value energy form – to raise air or water temperatures by only a few degrees is considered a wasteful way to create heat. It is often termed, "using a chainsaw to cut butter." As a result, the conversion of buildings heated all-electrically (many of which are in rural areas) to use geothermal heat pumps, biomass or solar sources of renewable energy can produce multiple benefits (ex: lower energy costs, new local jobs, freeing up more electricity for Manitoba hydro exports)." For this reason, the Clean Energy Strategy includes the following two goals (Manitoba 2012, p.4): • "Accelerate adoption of geothermal heating and cooling systems through Manitoba's green building policy, available financial incentives and by promoting community scale district heating opportunities. • Grow the province's biomass heat industry by directing revenue from the emissions tax on Coal to the Manitoba biomass energy support Program." In Chapter 2 of the NFAT, Manitoba Hydro notes (Manitoba Hydro 2013, C.2 p.12) "Due to the expectation that a larger proportion of customers will continue to choose electricity for space and water heat as well as miscellaneous end-uses, the average energy usage per residential customer is expected to rise by 0.4% /year. Electricity is currently used for space heating by approximately 35% of Residential Basic customers—forecast to grow to approximately 40% by 2031/32 as a progressively higher percentage of new homes and apartments choose electricity for space heating. Electric water heating is currently used by approximately 47% of Residential Basic customers – forecast to grow to approximately 69% by 2031/32 in the 2012 Load Forecast. The current trend is for new homes to install electric water heaters; in addition, a growing number of existing natural gas water heaters are also being replaced with electric units." With regards to biomass heating, beyond being a generally more appropriate use of energy, biomass also offers advantages for peaking loads and system reliability. Biomass can be easily stored, and this allows for the cold spells of Manitoba winters to be addressed without the added generation requirements proposed by Manitoba Hydro. Likewise, as noted in the Clean Energy Strategy (Manitoba 2012, p.15), if both HVdc transmission facilities fail in the winter months, up to 300,000 people could be without power or heating. By contrast, biomass does not suffer such vulnerabilities.

QUESTION:

"Please describe the extent to which electric space heating is considered an undesirable way to heat in Manitoba, the steps Manitoba Hydro has taken to discourage its use and what steps Manitoba Hydro could take to discourage such inefficient forms of heating.

RESPONSE:

Manitoba Hydro encourages customers to choose the most economic space heating system which best meets their needs and circumstances. Where other fuel sources, such as bioenergy, natural gas or geothermal, are economically available, Manitoba Hydro encourages customers to choose those options over electricity.

Complimenting the Provincial government's Manitoba Biomass Energy Support Program (MBESP) Manitoba Hydro supports and encourages bioenergy through its Bioenergy Optimization Program which focuses on technical information and incentives for bioenergy feedstock treatments and various thermal and electric conversions of those biomass feedstocks.

Manitoba Hydro has and continues to support the adoption of geothermal heating systems in electric-only service areas through research, education, capacity building, innovative financing, and incentives under the Power Smart Commercial Geothermal Program, Residential Earth Power Loan and Community-based Geothermal Program.

For a description of additional Manitoba Hydro's efforts to encourage customers to choose natural gas for heating, please refer to Manitoba Hydro's response to PUB/MH I-253(b).

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Page No.: p.12

PREAMBLE: In the Manitoba Clean Energy Strategy, the Government of Manitoba notes the value of non-electric heating systems. For example, page 30 of the Clean Energy Strategy notes (Manitoba 2012, p.30) "Historically, electric heat was the main alternative for those Manitobans who needed a stably-priced alternative to natural gas. As a result, 130,000 families use all electric heat (especially in rural areas and apartments) today and 230,000 use electric hot water. Even so, using electricity – a high value energy form – to raise air or water temperatures by only a few degrees is considered a wasteful way to create heat. It is often termed, "using a chainsaw to cut butter." As a result, the conversion of buildings heated all-electrically (many of which are in rural areas) to use geothermal heat pumps, biomass or solar sources of renewable energy can produce multiple benefits (ex: lower energy costs, new local jobs, freeing up more electricity for Manitoba hydro exports)." For this reason, the Clean Energy Strategy includes the following two goals (Manitoba 2012, p.4): • "Accelerate adoption of geothermal heating and cooling systems through Manitoba's green building policy, available financial incentives and by promoting community scale district heating opportunities. • Grow the province's biomass heat industry by directing revenue from the emissions tax on Coal to the Manitoba biomass energy support Program." In Chapter 2 of the NFAT, Manitoba Hydro notes (Manitoba Hydro 2013, C.2 p.12) "Due to the expectation that a larger proportion of customers will continue to choose electricity for space and water heat as well as miscellaneous end-uses, the average energy usage per residential customer is expected to rise by 0.4% /year. Electricity is currently used for space heating by approximately 35% of Residential Basic customers—forecast to grow to approximately 40% by 2031/32 as a progressively higher percentage of new homes and apartments choose electricity for space heating. Electric water heating is currently used by approximately 47% of Residential Basic customers – forecast to grow to approximately 69% by 2031/32 in the 2012 Load Forecast. The current trend is for new homes to install electric water heaters; in addition, a growing number of existing natural gas water heaters are also being replaced with electric units." With regards to biomass heating, beyond being a generally more appropriate use of energy, biomass also offers advantages for peaking loads and system reliability. Biomass can be easily stored, and this allows for the cold spells of Manitoba winters to be addressed without the added generation requirements proposed by Manitoba Hydro. Likewise, as noted in the Clean Energy Strategy (Manitoba 2012, p.15), if both HVdc transmission facilities fail in the winter months, up to 300,000 people could be without power or heating. By contrast, biomass does not suffer such vulnerabilities.

QUESTION:

Please report any analysis performed by Manitoba Hydro to determine the potential for biomass heating and geothermal heating, including the potential for market stimulation and social and technological innovation (including through collaboration with the provincial government).

RESPONSE:

Manitoba Hydro has and continues to support bioenergy heating and geothermal heating as a viable heating alternative in the Manitoba market.

In 2010, Manitoba Hydro commissioned a study to evaluate the potential for biomass as a fuel for heating. The study identified opportunities in Manitoba for heating with biomass fuels. Please see the attached report entitled "Heating with Biomass: Using a Manitoba Renewable Resource Manitoba, Hydro Biomass Fuel Heating Study".

Manitoba Hydro currently has the Power Smart Bioenergy Optimization Program available for qualifying agricultural and industrial customers in Manitoba. The program focuses on customers with readily available low cost sources of biomass, operational capability and continual needs for heat and power. The program is currently featuring a series of technology demonstration projects which is a collaborative effort between the Government of Canada, Manitoba Hydro and the sites hosting the demonstration.

With respect to geothermal, Manitoba Hydro has and continues to support the development of the geothermal heat pump market in Manitoba since 2002 through its Earth Power Program. Throughout this period, Manitoba Hydro has worked with industry and the Province of Manitoba to build market awareness and industry capacity to expand the geothermal heat

pump market in Manitoba. A summary of key industry infrastructure initiatives undertaken by the Earth Power Program are outlined below:

50) Launched Residential Earth Power Program in 2002
   - Offer financing of geothermal system to residential customers through a cost recovery loan. Currently with a maximum 15 year term, up to $20,000 can be financed at 4.9% (fixed 5-year rate).
   - Outlined qualifying standards for installations in Manitoba.

51) Organization (host and subsidize) of geothermal industry training sessions (2002 - 2006)
   - Training courses supported: IGSHPA Installers course, Commercial Design Seminar, HRAI's Heat Loss Calculation, HRAI's Air System Design and HRAI's Radiant Hydronic Design courses (offering 23 sessions overall with 375 successful participants).
   - In 2004, received HRAI's Education Supporter Award.

52) Organization (host and subsidize) of 2005 & 2006 Manitoba GeoExchange Conferences with a total of 485 delegates (250 in 2005 and 235 in 2006).

Manitoba Hydro, working with industry and the Province of Manitoba, coordinated the development of the Manitoba Geothermal Energy Alliance in 2006 to provide training, industry development, and installer certification and quality assurance. Manitoba Hydro provided significant financial and administrative resources to assist implementation of association initiatives. In addition and continuing today, Manitoba Hydro recognizes MGEA certification as the sole requirement for Manitoba Hydro's Power Smart Earth Energy programs.

In 2009, Manitoba Hydro completed an extensive study on the field performance of ten ground source heat pumps. The objective of the year long monitoring project was to determine the average annual seasonal coefficient of performance (SCOP) of systems that were designed and installed by knowledgeable, experienced contractors. Please see attached report "Performance

of Ground Source Heat Pumps in Manitoba". Similar monitoring is being planned for two homes on First Nations communities.

Manitoba Hydro has provided technical and financial support for commercial geothermal installations since 1995, first under its Power Smart Commercial Custom Program and in 2007 formally launching the Commercial Geothermal Program. More recently, Manitoba Hydro has launched two new financing programs that support the installation of geothermal heat pumps; the Residential Pay As You Save (PAYS) Financing Program in 2012 and Commercial PAYS Financing in 2013. PAYS is a convenient and affordable on-bill financing option for residential and business customers who want to upgrade to energy efficient technologies for their homes or buildings, including geothermal heat pump systems.

In 2013, Manitoba Hydro partnered with Aki Energy, a non-profit social enterprise, whose goal is to increase geothermal installations on First Nation communities while creating job and business opportunities, and launched the Community Geothermal Program. Installation training and certification is provided to local Band members by Aki Energy and Manitoba Hydro provides technical guidance, and a combination of financing through PAYS and financial support for the geothermal systems. This initiative is expected to realize an estimated 100 new geothermal systems installed in 2013 across two First Nation communities with four additional First Nations being approached for 2014.

Heating with Biomass:
Using a Manitoba Renewable Resource

Manitoba Hydro Biomass Fuel Heating Study

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1. Preface

This study, commissioned in July 2009, set out to do the following:

Purpose:
To determine the contribution biomass can make as a heating fuel for small and mid-scale customers in Manitoba.

Scope:
This study determines the amount of thermal energy which can be economically and sustainably derived through the conversion of biomass (from forest, crop and other sources) to heat for institutional, community and residential applications in Manitoba.

Objectives:
The study covers the following items:

1. **Global, Canada and Manitoba – Energy Overview (Section 3):** A brief summary of current energy production and consumption.
2. **Biomass Feedstocks (Section 4):** An examination of the amount of biomass available from crop and forest residues as well as other sources in Manitoba and its corresponding energy value.
3. **Biomass Technologies (Section 5):** A review of the range of technologies available to convert biomass to heat.
4. **Biomass Heat Applications (Section 6):** A survey of several locations where biomass is being used to provide heat in Manitoba, and around the world.
5. **Environmental Implications (Section 7):** An analysis of the potential impacts of large-scale biomass to energy conversion.
6. **Manitoba Biomass Industry (Section 8):** A synopsis of the capacity of the industry to manage the biomass life cycle, including the markets, infrastructure, policy, partnerships, investment, research & development, and logistics involved.
7. **Conclusions and Recommendations (Section 9):** A summary of the findings of this study including an analysis of which types of applications would qualify as the best applications for biomass based energy systems now, as well as, those which could be prospects in a five to thirty year time frame depending on factors including availability of fuel stocks, market conditions and government policy.

Acknowledgement and Thanks

In order to accomplish these objectives, Manitoba Hydro provided DLF Consulting with a number of studies and information which was fed into this study. Of particular note and help were studies completed by Prairie Practitioners Group (Manitoba Straw Study, and the Biomass Conversion Feasibility Study Supplier Analysis), Tyrchniewicz Consulting (Biomass Conversion Feasibility Study) and PricewaterhouseCoopers (Manitoba Wood Biomass for Heating and Energy Feasibility Study). References to these studies and other directly quoted materials are indicated by italicized text.

Special thanks are extended to Manitoba Hydro, and in particular to Deny St. George, Jeremy Langner and Ray Boris for their time and assistance in this project.

2. Executive Summary

Heating with Biomass: Using a Manitoba Renewable Resource is a report prepared for Manitoba Hydro which demonstrates that Manitoba's wealth of biomass resources can significantly contribute to reducing the Province's environmental footprint by providing a renewable source of heat. This use of biomass resources can help Manitoba achieve its "Beyond Kyoto" objectives and supports several of Manitoba Hydro's strategic corporate goals:

- *Be proactive in protecting the environment and the leading utility in promoting sustainable energy supply and service" (#7)*
- *Proactively support agencies responsible for business development in Manitoba"(#9)*
- *Be a national leader in implementing cost-effective energy conservation and alternative energy programs (#10).*

In 2009, this study began its work to determine the:

- total amount of agricultural and forestry biomass resources in Manitoba. *(Biomass is defined as any material, excluding fossil fuels, which is or was a living organism that can be used as a fuel directly or after a conversion process. Peat is not a biomass.)*[1]
- available technologies to convert those resources to heat
- best applications to convert existing facilities to biomass heat
- environmental implications of large-scale biomass to energy conversion
- capacity of the Manitoba biomass industry.

Key Findings

Manitoba Energy Overview:

- Manitoba's overall energy use is primarily non-renewable, comprising of petroleum products (40%), natural gas (30%), hydro-electricity (27%), and other fuels (3%).
- Energy rates in Manitoba are low: residential electric rates are approximately $0.06 per kWh; and natural gas rates are approximately $0.38 per cubic meter.
- Manitoba's primary heating fuel is natural gas, with heating also provided by electricity, propane, fuel oil, coal and wood. Fossil fuels used for heat in Manitoba deliver 64.5 petajoules (PJ = 10^{15} joules) per year @90% efficiency: natural gas – 56.7 PJ; coal – 5.5 PJ; and propane – 2.3 PJ with combined CO_2 emissions of 3.9 million tonnes per year. No precise figures for wood or fuel oil usage were identified.
- Manitoba imports an estimated 400,000 tonnes of coal per year for heating, more than half of which is used by Hutterite colonies. Coal has been targeted by a new provincial tax of $10 per tonne of CO_2 in 2011, which will result in a $20 to $30 per tonne increase.
- In addition to load reduction through conservation, other renewable heating options include biomass, hydro-electricity, solar thermal, and wind generated electricity.

[1] ASTM E1705 definition

Biomass Feedstocks

- The primary renewable feedstocks (Table 1.1) used for heat in Manitoba are by-products from both agricultural processing (125,000 tonnes of oat hull pellets, flax shives and sunflower hulls) and the forestry industry (48,000 tonnes of wood chips, hog fuel, cut logs and sawdust). If completely used these resources could generate 2.6 PJ per year @ 90% efficiency (agriculture – 2.1, forestry – .5).
- Manitoba produces 12.7 million tonnes (198 PJ @ 90% efficiency) of agricultural crop residue biomass per year (straw from wheat, canola, oats, barley, flax, corn, sunflowers, and beans). Of this, only one third should be taken for energy use based on conservation needs, resulting in an adjusted total of 4.2 million tonnes (64.2 PJ @ 90% efficiency). The energy values of this residual agricultural biomass range from a high of 24 MJ/kg (sunflower) to a low of 16 MJ/kg (wheat). Very little of this resource is presently used to generate heat.
- Unlike the annual cycles of agriculture biomass, the forestry biomass cycles are many years in length. Manitoba's total inventory of forestry biomass is 214 million tonnes, and if 2% were made available annually for heating purposes (assuming a 50 year cycle), this resource could provide 4.3 million tonnes (38.5 PJ @ 90% efficiency assuming10 MJ/kg due to high moisture content). Dried woody biomass (17 MJ/kg) yields would be up to 70% higher but would require additional energy inputs.
- Manitoba has 1.7 million tonnes (16.3 PJ @ 90% efficiency) of other forestry biomass including: unallocated fibre; allocated undercut; logging residues; and sawmill residues – of which less than 3% (0.50 PJ) are presently used to generate heat. A modest increase in the use of this resource would result in an annual total of 240,000 tonnes (2.2 PJ).
- Although the combined amount of agricultural and forestry residues (8.5 million tonnes – 102.7 PJ) could provide more than enough heat to replace all of the Province's fossil fuelled heating needs, the majority of this biomass is not available for heating purposes unless developments are made to recover and distribute the material as a fuel.
- Both the agriculture and forestry industries are developing fuel crops with higher yield per hectare (up to three times more) which have the capacity to significantly increase the amount of biomass available for heating purposes.

Table 1.1 Manitoba Biomass Feedstocks

Manitoba Biomass Resource	Processing Residues	Potentially Available Biomass	Total Biomass Available
	Tonnes (PJ)	Tonnes (PJ)	Tonnes (PJ)
PRESENT			
Agriculture	125 K (2.1)	0	12.7 M (198)
Forestry	48 K (0.5)	1.7 M (16.3)	214.0 M (2140)
Totals	173 K (2.6)	1.7 M (16.3)	NA
POTENTIAL			
Agriculture	125 K (2.1)	4.2 M (64.2)	12.7 M (198)
Forestry	240 K (2.2)	4.3 M (38.5)	214.0 M (2140)
Totals	365 K (4.3)	8.5 M (102.7)	NA

Notes: Energy conversion efficiency of 90% used for all energy outputs. PRESENT section – No "potentially available" agriculture biomass is noted as Manitoba has no mature straw burning technologies functioning at present. The total is listed as "NA" as the two amounts cannot be added because the agricultural figure is an annual total, and the forestry figure is (nearly) all the standing trees in Manitoba. POTENTIAL section – No projected increase is noted for agriculture processing residues as this figure is dependent not on the biomass market, but on the agricultural product processing market.

Biomass Conversion Technologies

- The technologies which convert biomass to heat include: combustion (primary and dual stage); gasification; and pyrolysis – including torrefication and carbonization. Of these, all of Manitoba's present biomass heating applications use combustion technology with boilers, some of which are manufactured locally. These units have traditionally used coal, and many are now using biomass in the form of wood chips, wood pellets, oat hull pellets, sunflower hulls, and flax shives.
- New biomass technology developments underway Manitoba include: testing of locally invented technologies (dual stage combustion); plans to install an imported technology (gasifier); and research on new technologies (organic rankine cycles).
- The next five years should see the installation of several combined heat and power (CHP) gasifiers, secondary combustion units and pyrolysis-related technologies.

Biomass Heat Applications

- Manitoba's primary use of biomass for heat is residential (wood related products) and commercial (loose or densified agricultural and forestry residues) with Hutterite colonies and greenhouses being the primary applications.
- Canadian examples of heating with biomass include district heating (cluster of buildings and/or homes), the heating of individual buildings (institutional, commercial, agricultural or industrial), and residential heating.
- Although nearly every building in the province requires heat, the task of using biomass to heat buildings requires either the use of densified biomass to substitute for existing coal use, or new systems requiring storage and handling of baled agricultural residues or loose forestry residues.
- District heating, very common in Europe, was also part of Winnipeg's historical heating paradigm, but is largely abandoned; leaving a downtown dependent on numerous discrete natural gas fired heating systems.

Environmental Implications

- Removing biomass (whether agricultural or forestry) has implications for the land as its removal can impact the soil's ability to prevent erosion, retain nutrients, build soil tilth and conserve moisture.
- The need to conserve biomass varies across the Province based on different types of soils, types of farming or wood harvest being done and other environmental factors.
- Emissions are created from the gathering, transportation, and processing of the biomass, and the combustion of the biomass itself generates emissions in addition to fly and bottom ash.

Manitoba's Biomass Industry

- The transportation and equipment infrastructure is largely in place to handle the biomass from the forest or field to a heating location.
- Biomass densification is in the development stages, with capacity to grow given the right market conditions.
- Local biomass stoker boiler manufacturers and markets are mature with well established technologies, fuel sources and applications (e.g. Hutterite colonies).

Conclusions

1. Manitoba's existing low energy price structures do little to encourage alternative renewable energy technologies, although the new coal tax is a step in the right direction.
2. Manitoba's renewable energy ratio (percentage of its energy use that is renewable) has not changed significantly in the past 20 years.
3. Solar thermal and wind can provide significant amounts of energy but require a backup energy resource which biomass can provide as a base load heating resource.
4. Manitoba's biomass resources are sufficient to provide for a majority of the Province's heating needs.
5. The biomass which is now being used for heat is primarily by-products from agricultural and forestry processes.
6. The majority of Manitoba's agricultural and forestry biomass resources are not used for heating purposes.
7. Manitoba's forestry biomass represents a huge renewable resource which has the potential to play a larger role in the Provincial energy picture. The greatest economic potential for forestry biomass has historically been lumber and pulp/paper, but future economic scenarios may place this resource as Manitoba's largest renewable heating fuel.
8. Biomass heating technologies presently being used are combustion systems designed for densified or loose by-products of agricultural and forestry processes.
9. New commercial and/or residential developments provide an ideal opportunity to integrate biomass fired district heating.
10. The types of locations in Manitoba which may be the best suited for the biomass-to-heat applications are as follows:
    a. Rural businesses or towns located close to sawmill/forestry operations which can access a steady supply of processed biomass (e.g. sawdust) at no to low cost, feed it into a boiler unit and use it in a hot water heating loop.
    b. Hutterite colonies and greenhouses with existing boiler systems providing hot water heat. These facilities can access the existing locally processed biomass fuel sources (e.g. oat hulls, wood chips, flax shives) available to provide a steady, reliable flow of energy.
    c. Small towns (including reserves) within 50 km of biomass supply (forestry or agriculture) which have existing hot water boiler systems.
    d. Industrial facilities producing biomass, integrating it into their own heat processes. No transportation of biomass would be required.
11. The use of biomass as a heating fuel carries an energy cost, has environmental implications and a lifecycle which need to be fully considered when substituting for fossil fuels.
12. Manitoba's biomass infrastructure includes all the necessary components (suppliers, transporters, densifiers, boiler manufacturers) to continue developing the biomass sector, and is in a good position to grow when either incentives or fossil fuel prices provide the reason to expand.

Lessons from Denmark
As part of this study, special attention was paid to the biomass situation in Denmark, a country using biomass as a key component of its renewable energy strategy. The following is adapted from information prepared by FORCE Technologies of Denmark for this study.

Danish energy policy focuses on a secure energy supply, awareness of the environmental and climate aspects of the use of energy, and cost effectiveness of energy supplies. In order to address its complete dependency on imported oil, the Danish Government has put an emphasis on increased energy efficiency, use of waste heat from power stations and a strong growth in district heating. Other initiatives have led to increased use of renewable energy, including biomass and waste. One result of these policies is that Danish companies and research institutions today are internationally acknowledged for the development of new energy technologies. The Danish export of energy technology has in recent years grown faster than the overall Danish exports and today the energy technology export sector constitutes approximately 10 % of the total Danish exports in 2008.

Currently, renewable energy accounts for 13.8% of Denmark's total energy use. Biomass currently accounts for 70 to 75 % of renewable energy consumption, mostly in the form of straw, wood and renewable wastes and biogas. Consumption of biomass for energy production in Denmark more than quadrupled between 1980 and 2005. Agricultural and forestry biomass accounts for approximately 60 PJ of the total 120 PJ derived from renewable energy resources.

Recommendations:
As a result of this study, DLF Consulting has prepared the following recommendations which Manitoba Hydro may consider:

1. Support feasibility studies to identify appropriate biomass heating applications for commercial operations, small towns, Hutterite colonies, greenhouses, and district heating applications.
2. Encourage use of biomass for heat and consider incentive based programs to assist with the transformation of the market.
3. As Manitoba's primary biomass resource is straw, and given that this resource can be used directly for heat (without densification), provide a demonstration of how this can be done with established leading edge biomass technologies in Manitoba (e.g. the well proven straw-to-heat technology from Denmark).
4. Develop a neutral information source to provide information on biomass feedstock and technologies options.
5. Develop an energy partnership with a similar sized European district presently utilizing biomass for district energy.
6. Investigate ways to finance greener and more sustainable technologies (e.g. clean technology funds) and explore what other countries are doing with sustainable initiatives to tap into public interest and environmental awareness.

Supportive measures by the Manitoba Government may include:

7. Establish biomass-to-heat as an energy policy priority as it provides one of the few actual ways to decrease importation of non-renewable fuels (e.g. establish biomass fired district heating as a requirement for new developments).
8. Study the impact of crop and forestry residue removal and create guidelines for its sustainable use.

9. Develop grants and tax incentives for those developing biomass recovery and processing businesses (e.g. densification) and thermal conversion equipment.
10. Work with financial institutions to subsidize loans at low interest rates to increase the attractiveness of these investments.
11. Create air emissions policies which balance emissions priorities with GHG emission, permitting more biomass fuel users.

3. Introduction

The convergence of growing local and global environmental awareness, Manitoba's "Beyond Kyoto" plans and Manitoba Hydro's interest in developing additional renewable solutions together provide a unique window of opportunity to examine the biomass resource to build local energy self-sufficiency. Manitoba Hydro in its strategic corporate goals[2] states that it plans to:

- *Be proactive in protecting the environment and the leading utility in promoting sustainable energy supply and service" (#7)*
- *Proactively support agencies responsible for business development in Manitoba"(#9)*
- *Be a national leader in implementing cost-effective energy conservation and alternative energy programs (#10).*

As part of its implementation of these goals, Manitoba Hydro commissioned this study to investigate the potential role of biomass can have as a heating fuel in Manitoba's long term energy future. Biomass is a renewable, greenhouse gas neutral resource which Manitoba has in plentiful supply, and while many options exist to generate energy, this study focuses on the heating contribution biomass can make to Manitoba's energy future.

Decisions regarding how homes, businesses and institutions will be heated are being impacted by a combination of factors including economics, convenience (ease of access) and speculation as to which resources will be around for the foreseeable future. The heating of water and space with natural gas has been the logical choice to date; however given that gas is an imported non-renewable resource, it is reasonable to expect that its price will rise as availability decreases. Consumers will look for alternatives, which at present includes wood and pellet stoves, geothermal, solar and electric resistance heat.

Other consumers (primarily industry and the Hutterite colonies) are using coal to heat (given its price and convenience), and are faced with a new (2011) Provincial tax which will increase the price of coal. This tax, designed to decrease emissions and reliance on fossil fuels, will push coal consumers to look for heating alternatives, which may include electricity as an affordable option. Increased use of hydro-electric generated electricity will lead to decreased exports, and reduced provincial earnings – a result which to be avoided will require an intense pursuit of sustainable alternatives including an examination of biomass as a heating fuel.

Biomass used for heat

The generation of heat through the combustion of biomass is one of the oldest human methods used to provide heat and warmth. Later, coal was used to provide a higher grade of heat for the working of metals, as well as steam for work and transportation. Certain parts of the world were able to access tars and gas seeping from the ground, followed by the discovery of oil and all its many derivatives. These were not only preferable to wood, in terms of greater energy density, but relative ease of

[2] Manitoba Hydro Annual Report, 2008

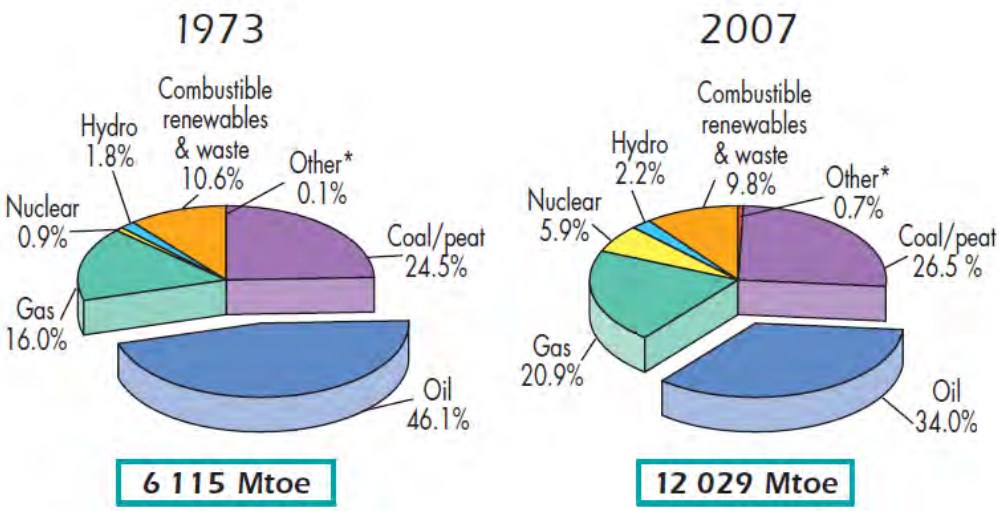
transportation, storage and use by millions and now billions of people. Other sources of energy, including nuclear and renewable technologies (hydro, wind, solar, biomass) have grown in prominence over the past decades, but still remain small in the larger energy picture.

To provide the context in which Manitoba operates, the following section provides information regarding energy production and use globally, nationally and provincially.

3.1 Global and Canada Energy Overview

The dependence upon fossil fuels over the centuries has increased to the point that nearly 87% of all the energy produced on this planet is derived from fossil fuels (Figure 3.1).

Figure 3.1: Global Total Primary Energy Supply[3]



Mtoe is millions of tons of oil equivalent

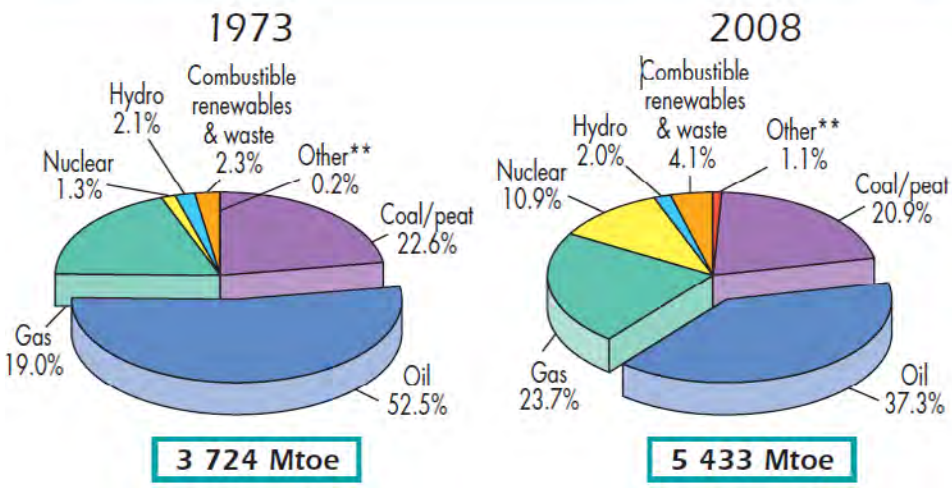
* Other includes geothermal, solar, wind, heat, etc.

Looking specifically at the renewable energy portion of Figure 3.1shows that it has grown slightly (12.5 to 12.7%) with the largest change being the use of oil (down 12%). Use of other resources has grown with gas (up 5%), coal/peat (up 2%) and nuclear growing to nearly 6%.

The picture in the Organization for Economic Cooperation and Development (OECD) countries is similar, but cogent to this report, shows an increase in the "combustible renewables and waste" category of 80% (from 2.3 to 4.1%). The use of coal/peat, hydro and oil has decreased with increases shown in the nuclear and gas sectors (Figure 3.2).

[3] International Energy Agency: http://www.iea.org/textbase/nppdf/free/2009/key_stats_2009.pdf

Figure 3.2: OECD Total Primary Energy Supply[4]



** Other includes geothermal, solar, wind, heat, etc.

Canada

Canada's energy production is 47% greater than its consumption (see PJ totals in Table 3.1), with the difference being exported to the USA. More of all Canada's natural resources (natural gas, petroleum, coal, hydro, nuclear and wood) are produced than consumed with the majority of exports being natural gas and petroleum (Figure 3.3).

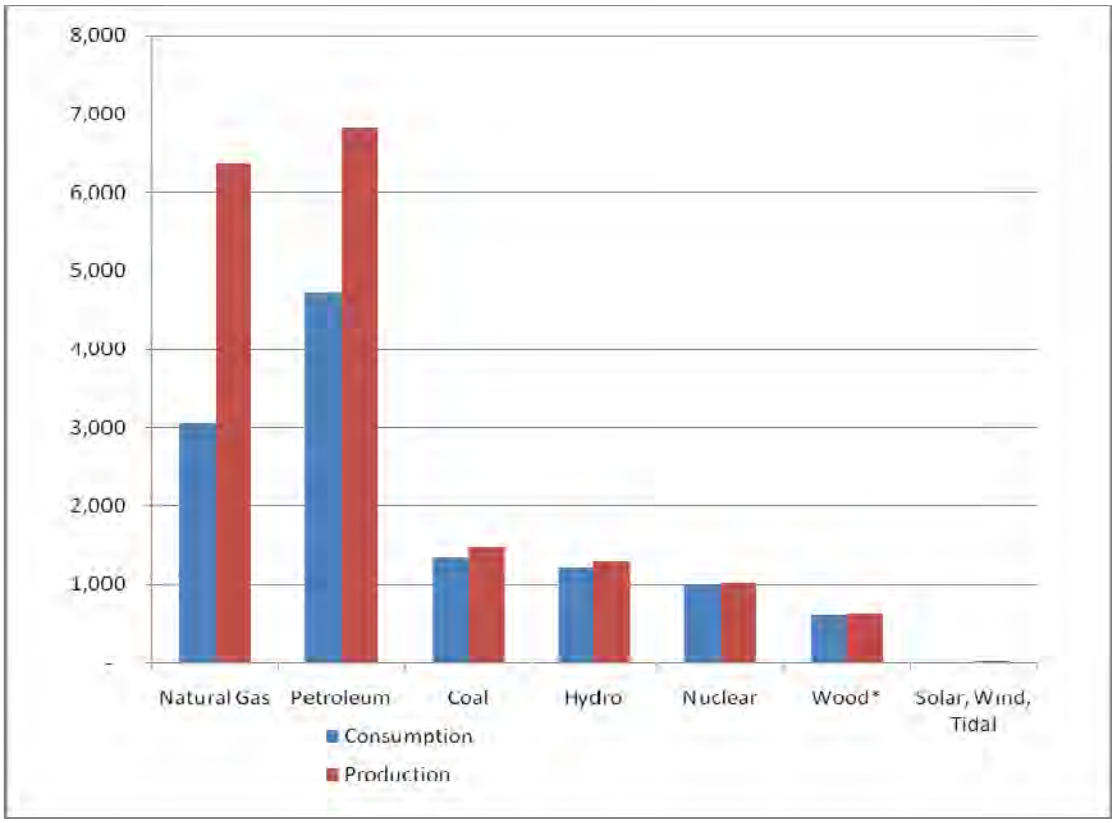
Regarding Canada's energy production and consumption, "*Alberta accounted for 64 percent of total production; British Columbia, 13 percent; Saskatchewan, 9 percent; Quebec, 4 percent; and Ontario, 3 percent. Ontario accounted for 35 percent of (Canada's energy consumption); Alberta, 23 percent; Quebec, 17 percent; British Columbia, 11 percent; Saskatchewan, 5 percent; Manitoba, 2 percent; and the Atlantic provinces, 7 percent.*"[5]

Table 3.1: Canada Energy Statistics 2007[6]

Energy Source	Production	PJ	Consumption	PJ
Natural Gas	36.1%	6,370	25.5%	3,051
Petroleum	38.7%	6,829	39.4%	4,714
Coal	8.4%	1,482	11.3%	1,352
Hydro	7.4%	1,306	10.1%	1,208
Nuclear	5.8%	1,023	8.5%	1,017
Wood	3.5%	618	5.1%	610
Solar, Wind, Tidal	0.1%	18	0.1%	12
Total		**17,645**		**11,965**

[4] International Energy Agency: http://www.iea.org/textbase/nppdf/free/2009/key_stats_2009.pdf
[5] Natural Resources Canada: http://www.nrcan-rncan.gc.ca/stat/energ-eng.php#a2
[6] Natural Resources Canada: http://www.nrcan-rncan.gc.ca/stat/energ-eng.php#a2

Figure 3.3: Canada Energy Production and Consumption 2007 (PJ)[7]



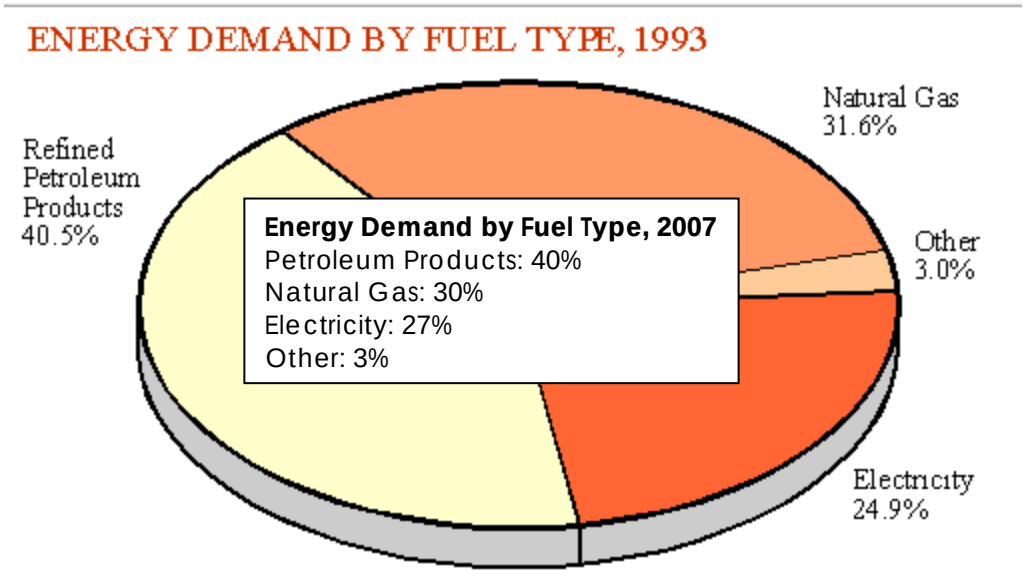
* Waste wood, spent pulping liquor and firewood

3.2 Manitoba - Energy Overview

Despite hydro-electric's high profile in Manitoba, the overall provincial energy picture is highly dependent upon fossil fuels, as shown in Figure 3.4. These statistics, spanning a period of 16 years (from 1993 to 2007), show little difference in the demand for petroleum products (40.5% to 40%), natural gas (30.1% to 30%), electricity (24.9% to 27%) and other – fuel oil, coal, wood (unchanged) over that period of time.

[7] Natural Resources Canada: http://www.nrcan-rncan.gc.ca/stat/energ-eng.php#a2

Figure 3.4: Manitoba Energy Demand[8]



Excluding petroleum products, Manitoba's energy use is dominated by natural gas, followed by electricity, fuel oil, coal and wood. Although all of these resources play a role in providing heat, the majority is provided by natural gas. The total amount of natural gas imported between April 2007 and March 2008 was 80.9 PJ, however, 17.8 PJ are used to produce fertilizer leaving a remainder of 63.0 PJ used in Manitoba for heat.[9] This amount, added to other fossil fuels presently being used to provide heat for Manitoba generate a total of 64.5 PJ (@90% efficiency): natural gas (56.7 PJ); coal (5.5 PJ – primarily lignite); and propane (2.3 PJ). No precise numbers for wood or fuel oil are currently available. The greenhouse gas emissions from these fuels total approximately 3.9 million tonnes CO_2 per year.[10]

Due to Manitoba's limited natural gas delivery infrastructure, rural heating needs are also provided by electricity, propane, coal and wood. In addition to this lack of availability of natural gas across the province, low electricity rates have given many customers reason to heat with electricity. According to Manitoba Hydro's 2008 Annual Report, residential electric consumption has risen 9% since 2004, in contrast to an increase of 3% for natural gas over the same time period. The average energy value of the coal used in Manitoba varies from a low of 15 GJ per tonne lignite coal from Saskatchewan to19 GJ per tonne subituminous coal from Montana.

[8] Manitoba Conservation: http://www.manitoba.ca/conservation/annual-reports/soe-reports/soe95/f8-01.gif, and Statistics Canada
[9] Manitoba Hydro 2008 Annual Report: http://www.hydro.mb.ca/corporate/ar/index.shtml and figures provided by Manitoba Hydro
[10] NRCAN, US Energy Information Admin. , Mass. Inst. Tech.: http://www.ec.gc.ca/pdb/ghg/inventory_report/2005_report/som-sum_eng.cfm#s4_2 , http://www.eia.doe.gov/oiaf/1605/coefficients.html, http://web.mit.edu/mit_energy/resources/factsheets/UnitsAndConversions.pdf

Policy and Pricing

Electricity rates in Manitoba are low, with rates remaining relatively constant from 2005 to present with rates (excluding demand charges) increasing from[11]:

- $0.0578 to $0.0638 per kWh - residential
- $0.0600 to $0.0684 - general services small
- $0.0244 to $0.0684 - general service medium
- $0.0228 to $0.0288 - general service large.

On an energy equivalency basis, Table 3.2 compares the relationship between price per energy unit (kWh and cubic meter) and its gigajoule equivalent. An electrical rate of $0.06 per kWh, for example will purchase the energy equivalent to natural gas at $0.59 per cubic meter (at 90% efficiency). The price of gas, however, is now $0.25 per m³, and with transportation and distribution charges is $0.38 per m³ which would require electricity to be $0.04 per kWh to be the equivalent price per GJ.

Table 3.2: Energy Price to Content Ratios[12]

Natural Gas Price	$ / Gigajoule Equivalent		Electricity Price
$/m³	Natural Gas @ 90% Eff.	Electricity @ 100% Eff.	$/kWh
0.19	5.51	5.56	0.020
0.24	6.96	6.94	0.025
0.29	8.41	8.33	0.030
0.34	9.86	9.72	0.035
0.39	11.31	11.11	0.040
0.44	12.76	12.50	0.045
0.49	14.22	13.89	0.050
0.54	15.67	15.28	0.055
0.59	17.12	16.67	0.060
0.64	18.57	18.06	0.065
0.69	20.02	19.44	0.070

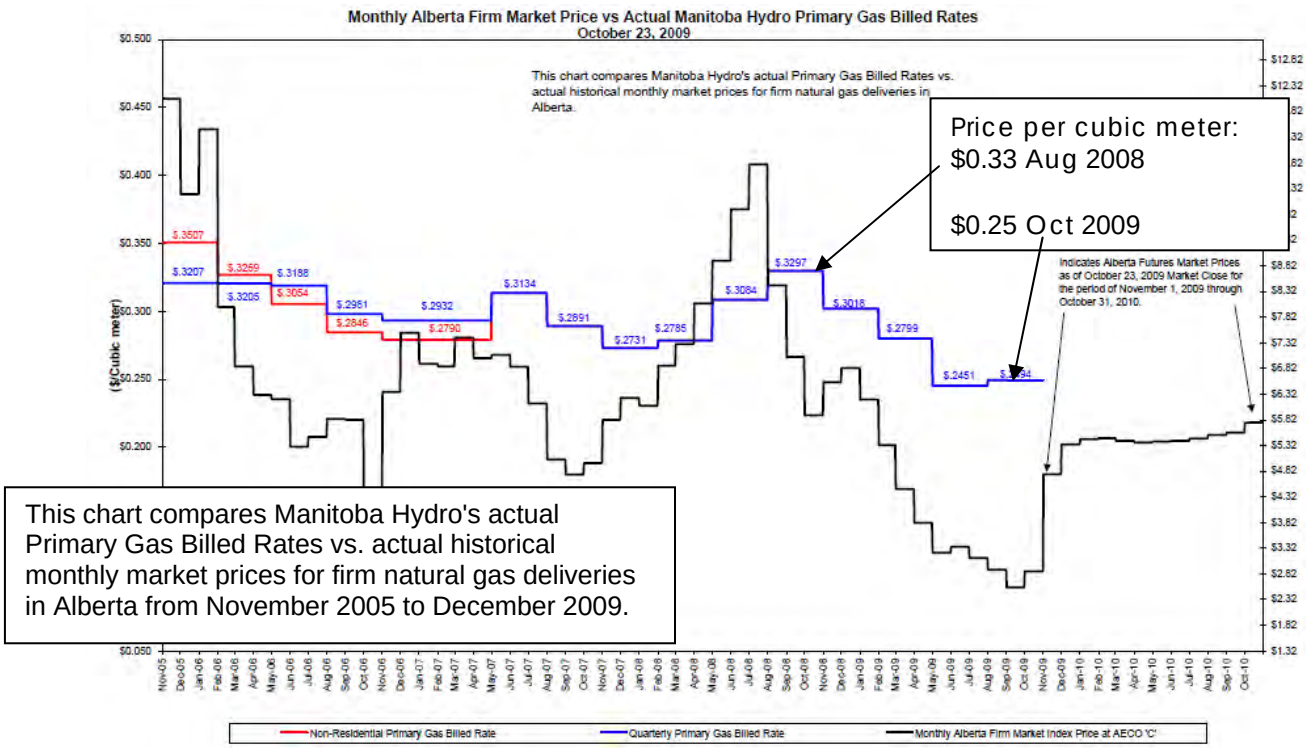
Less than a year ago natural gas prices were climbing and the two energy sources were closer to equivalency than they are now. Few expect natural gas prices to decrease further, but an increase of 45% would be required to bring energy price equivalency between electricity and natural gas.

The price of natural gas (Alberta Firm Market Price per m³), as the primary heating fuel in Manitoba has (since 2005) fluctuated from $0.46 (November 2005) down to $0.16 (November 2006), rising again to $0.41 (July 2008) to $0.10 (October 2009), and in December 2009 was $0.21 per cubic meter (Table 3.3). Manitoba Hydro's primary gas billed rates have helped even out these fluctuations providing natural gas to customers (over the same time period) at rates ranging from a high of $0.33 (August 2008) to a low of $0.25 (October 2009). The volatility of natural gas rates is a fact that Manitoba must live with given that the resource is imported and subject to market changes. A locally

[11] Manitoba Hydro: http://www.hydro.mb.ca/regulatory_affairs/energy_rates/electricity/historical.shtml#residential
[12] Manitoba Hydro, DLF Consulting

produced energy source such as biomass has the capability of providing greater energy stability and independence.

Table 3.3: Historic Natural Gas Rates[13]



Coal has been targeted by a new Provincial coal tax to reduce its use and accompanying GHGs. Coal use is estimated to be approximately 400,000 tonnes[14] (6.1 PJ) per year, more than half of that amount being used by the Hutterite colonies for heating agricultural and commercial buildings. (The amount of coal used in Manitoba is difficult to establish given the fact that much of it is transported from Saskatchewan without being monitored.) The new tax, to come into effect in 2011, is $10 per tonne of CO_2 emissions, which translates to an approximate 40% increase in the price of coal (based on a ratio of around 1,400 kg CO_2 emissions per tonne of lignite coal). The Province did not have the amount of the price increase per tonne of coal set at the time of the writing of this report.

Coal prices range from $95 per tonne for delivered high energy coal to $70 per tonne for lower energy value coal. Approximately half of this price is the trucking involved, and with the increased taxation, coal's price per gigajoule (@$70 per tonne, assuming 92 kg CO_2/GJ with 67% efficiency) is $8.16. Other energy prices are shown in Table 3.4 with oil topping the list at $21.05/GJ followed by residential electricity at $17.00/GJ. Natural gas is

[13] Manitoba Hydro: http://www.hydro.mb.ca/regulatory_affairs/energy_rates/natural_gas/centra_pricing_chart.pdf
[14] Statistics Canada, Hutterite users, Tyrchniewicz Consulting (MAFRI): Biomass Conversion Feasibility Study 2009, p. 9

priced at $9.17/GJ and the least expensive (other than coal) are biomass resources – wood, pellets and certain agriculturally derived biomass at less than $7.00 per GJ.

Other renewable heating options (other than hydro-electricity) include solar thermal, wind generated electricity, and biomass. Of these, solar and wind, while capable of providing vast amounts of energy, are options requiring storage and/or backup heating sources due to the lack of continuous sun and wind. Biomass as a fuel source can provide a base load of reliable heat energy to complement any other fuel source, whether renewable or non-renewable.

Table 3.4: Energy Prices and Types[15]

Energy Source	GJ/Unit	$/Unit	Unit	Cost/GJ of Fuel	Appliance Seasonal Efficiency	Cost/GJ of Heat (average efficiency)	kg of CO2e per GJ
Oil	0.038	0.80	litre	$21.05	60% - 89%	$28.26	87.9
Electric (residential)	0.0036	0.0612	kWh	$17.00	100%	$17.00	-
Electric (large general service rate, blended demand and energy, process load)	0.0036	0.04	kWh	$11.11	100%	$11.11	-
Natural Gas	0.0375	0.344	Cubic meter	$9.17	60% - 94%	$11.68	57.6
Propane	0.0253	0.42	litre	$16.60	60% - 94%	$21.55	73.7
Hardwood	30.6	180	Cord	$5.88	55% - 80%	$8.71	5.0
Softwood	18.7	125	Cord	$6.68	55% - 80%	$9.90	5.0
Wood Pellets	19.8	250	Tonne	$12.63	50% - 85%	$18.71	8.2
Lignite coal	15.3	70	Tonne	$4.58	50% - 85%	$6.79	93.1
Ag Biomass (dry basis)	16.3	110	Tonne	$6.75	50% - 85%	$10.00	5.0

It is in this context that biomass is being examined for use as a feedstock to provide heat to potentially displace not only coal use, but eventually to displace a percentage of the natural gas and electricity presently used for heat.

[15] Tyrchniewicz Consulting (MAFRI): Biomass Conversion Feasibility Study 2009, p. 8

4. Biomass Feedstocks

4.1 Introduction

Biomass is "the generic term for any living matter that can be converted into usable energy through biological or chemical processes. It encompasses feedstocks such as agricultural crops and their residues, animal wastes, wood, wood residues, grasses, and municipal wastes"[16] (Figure 4.1). According to ASTM biomass is defined as "any material, excluding fossil fuels, which is or was a living organism that can be used as a fuel directly or after a conversion process. Peat is not a biomass."[17]

"Interest in biomass has increased dramatically over the last 5 years as people seek out a renewable resource substitute for petroleum based fuels as well as an input into other industrial processes. The majority of biomass is found in rural areas, and as such the bio-economy has the potential to provide much needed diversification of the rural economy. The headlines often tout biomass as an alternative to oil, and while this has potential, it can also be used as input into consumer products such as linens and construction materials.

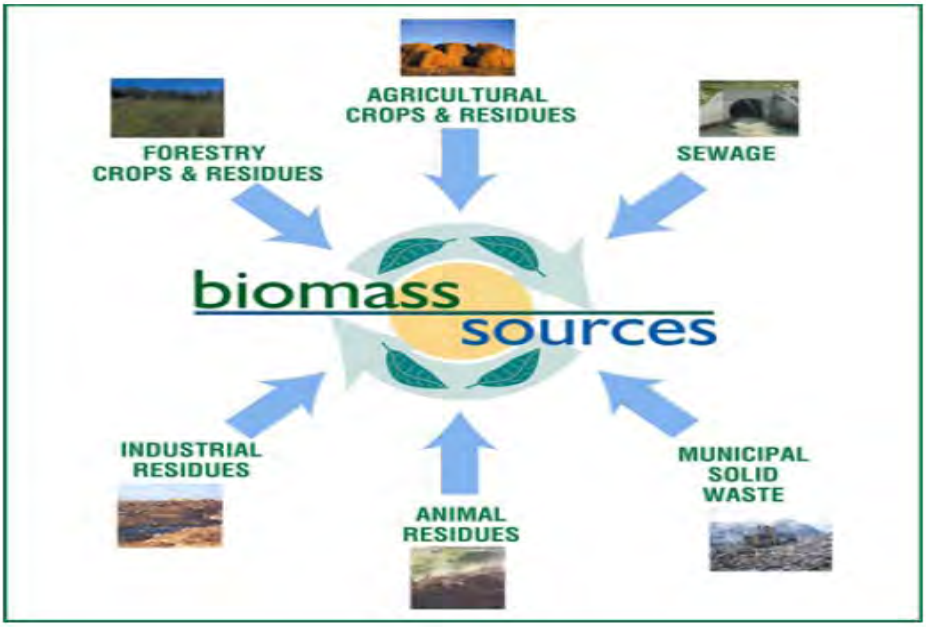
"The term biomass refers to living and recently living biological material which can be used as fuel or for industrial production, and commonly refers to plant matter grown for use as bio-fuel. Biomass also includes plant or animal matter used as inputs into the wider bio-based economy.

"The term bio-based economy refers to an economy derived from applying the advances in science and innovation to the biology of plants, animals and micro-organisms to develop new bio-products. Since bio-products can be generated from a variety of renewable resources, sustainable sources of power/energy, transportation fuels, chemicals and materials are possible. Bio-products can support growth of the rural economy by providing employment opportunities to grow and harvest biomass feedstocks, as well as refining the feedstocks into bio-products.

"Biomass is generally considered to be available from two sources, opportunity and purpose-grown. Agricultural residue, such as straw and corn stover, and woody material resulting from insect and disease attacks, major forest fires, timber harvesting operations and wood processing operations are considered to be the major opportunity biomass sources in Canada. Crops grown with the sole intent of supplying inputs to the bio-products or bio-energy industry are considered to be purpose grown sources of biomass. Examples of purpose grown biomass include switch grass, hybrid poplar, or willow plantations. When combined, Canada's agricultural and forestry inventories biomass will present a diversification in feedstocks and reduce the supply risk to the bio-industry from crop failure or tree loss to pests or fire."[18]

[16] Science Dictionary: http://www.sciencedictionary.org/agriculture-term-details/Biomass
[17] ASTM E1705 definition
[18] Agriculture Canada: About Biomass – BIMAT http://atlas.agr.gc.ca/agmaf (partial address)

Figure 4.1: Biomass Sources[19]



This study specifically examines the heating potential of agricultural and forestry crop residues, which in Manitoba include the following:

1. Agricultural residues:
   - wheat, barley, oat, soybean, canola, and flax straw
   - corn stover, sunflower residues
   - hemp stalks and by-products
   - agricultural processing by-products such as oat hulls, flax shives and sunflower hulls.

2. Forestry residues:
   - biomass left behind from logging operations such as branches and tree tops
   - trees cut for thinning purposes, killed by insect infestations or with no commercial value
   - woodchips from logging and/or lumber processing
   - forest processing by-products such as bark, sawdust and hog fuel.

Biomass has been used since pre-historic times to generate heat, which over time has been replaced by many other fuels. Table 4.1 provides an overview of a number of heating fuels, with the most energy dense fuel (propane) at nearly 47 MJ/kg to the least dense (miscanthus) rated at 12.1 MJ/kg with 25% moisture content. This same fuel at a moisture content of 11.1% will yield between 16 and 19 MJ/kg (similar to many other agricultural biomass sources). [20] A reduction in moisture content will increase the energy value as energy must be expended to evaporate the moisture in the fuel.

It is interesting to note that the highest performing fuels have only 2 to 2.5 times more energy than the renewable solid fuels mass basis. However, the volume required

[19] NRCAN: http://www.nrcan.gc.ca/eneene/sources/index-eng.php
[20] ECL Phyllis database: http://www.ecn.nl/phyllis/DataTable.asp

depends on its energy density and ranges from a high of 865 kg/m³ (oil) to a low of 160 kg/m³ for miscanthus. In other words, the space taken by less efficient fuels is up to 4 times higher than for more energy dense fuels.

Table 4.1: Energy Content of Fuel Sources[21]

	MJ/kg	kWh/kg	mid range kg/m³	mid range MJ/m³	Mid range kWh/m³	oil = 1.00
Wood Chips@30%mc	12.5	3.5	225	2800	781	12.77
Logs Stacked @20%mc	14.6	3.1	425	6205	1723	8.15
Wood Solid oven dried	18.6	5.2	500	9300	2583	3.86
Wood pellets @8-10 %mc	17	4.7	600	11050	3069	3.25
Miscanthus bales @25%mc	12.1	3.4	160	1936	550	18.13
Coal	29	8.1	850	24650	6847	1.46
Oil	41.5	11.5	865	35898	9972	1
Propane	46.9	13	500	23472	6520	1.5
Natural Gas[26]	na	na	na	36	10.1	997

4.2 Feedstock Analysis Tools

To analyze both the amount of energy in a given biomass feedstock, and its energy balance in order to understand the overall impact of using it for heat, or any other use, requires knowledge of what is being planted, how well the growing season has gone, how far the biomass feedstock is from any given destination, and what is required to prepare the feedstock for use. Several tools have been developed to quantify biomass energy content and its accompanying costs:

- Straw Procurement Spreadsheet (Prairie Practitioners Group)[22]
- Biomass Inventory Mapping and Analysis Tool (BIMAT) (Agriculture Canada)[23]
- Wood Energy Calculator (Michigan Wood Energy)[24]
- Biomass Calculator – related to soil quality (Soil Quality.org)[25]
- Biomass Calculator – wood (NRCAN)[26]
- National Forest Inventory (NFI)[27]
- Biomass Compare (NDSU)[28]

Each has its advantages and disadvantages, but for pure ease of use and availability of data, the BIMAT tool provides a unique window on biomass resources. A description of BIMAT includes the following:

[21] PricewaterhouseCoopers, (MAFRI) "Manitoba Wood Biomass for Heating and Energy Feasibility Study" 2009, p. 16
[22] Manitoba Agriculture, Food and Rural Initiatives (Prairie Practitioners Group): http://www.gov.mb.ca/agriculture/ri/community/pdf/straw_procurement.pdf
[23] Agriculture Canada: http://www4.agr.gc.ca/AAFC-AAC/display-afficher.do?id=1226509218872&lang=eng
[24] Michigan Wood Energy: http://michiganwoodenergy.org/calculator/calculator.php?action=form1
[25] Soil Quality: http://www.soilquality.org.au/calculators/carbon
[26] NRCAN: http://www.cfl.scf.rncan.gc.ca/calculateurs-calculators/biomasse-eng.asp
[27] National Forest Inventory: https://nfi.nfis.org/about_nfi/index_e.shtml
[28] NDSU: www.ag.ndsu.nodak.edu/abeng/pdffiles/BiomassCompare031309.xls

"Developing a bio-based economy - one based on products produced by plants, animals and microorganisms - requires accurate and reliable information about the biomass feedstock supply, production and harvesting costs, and environmental impacts.

"Although biomass can be purpose-grown, such as switchgrass intended for ethanol production, a considerable amount of it is 'opportunity' biomass, biomass that's a by-product or residue of some existing industry. Agricultural residue, straw and stover from wheat, corn and other crops, is one example; woody material left over from timber harvesting and processing, or even forest fires or pest infestations is another.

"Producers of bio-products need to know the types, quantities and qualities of biomass available by location to make effective use of this material. The ***Biomass Inventory Mapping and Analysis Tool (BIMAT)*** *provides that information. Accessible over the Internet, it offers interactive queries and thematic maps that can guide users to sources in Canada of precisely the kinds and amounts of feedstocks they need for their processing plants."*[29]

This tool provides the user with an array of choices including:

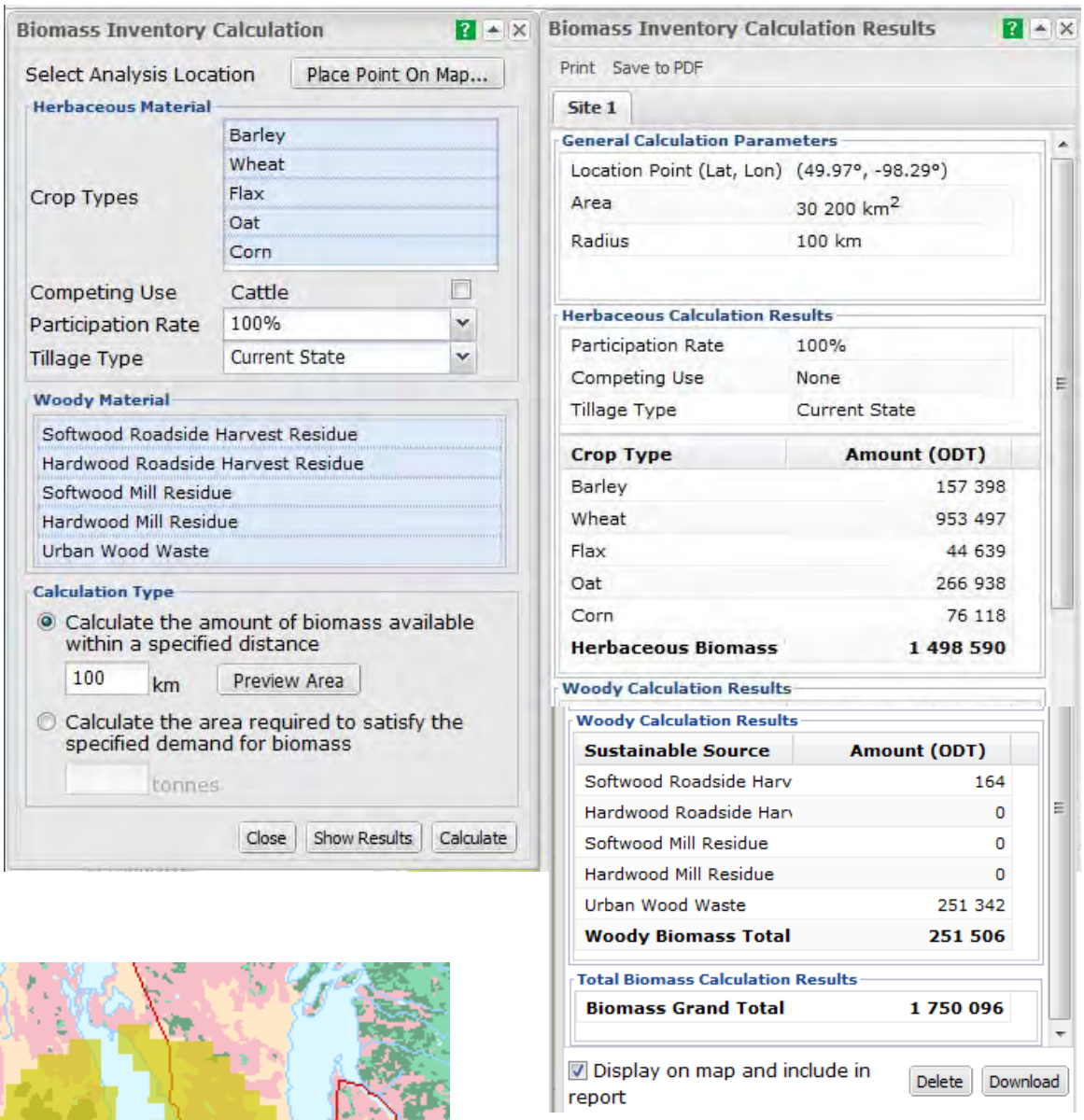
- Type of Agriculture Biomass (single or multiple)
- Type of Forestry Biomass (single or multiple)
- Location
- Radius OR Amount of biomass required

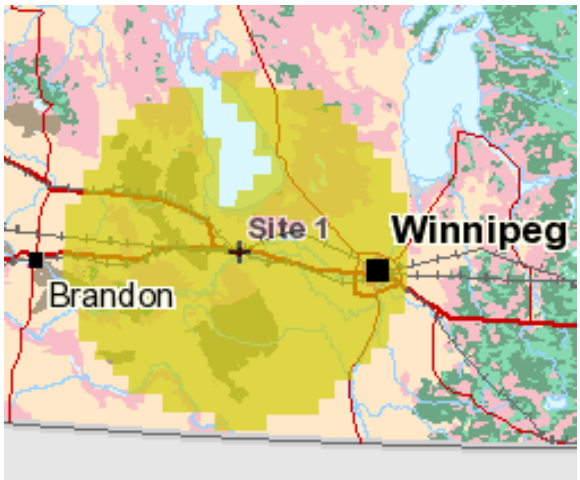
The results of a sample search – all biomass resources within 100 km of Portage La Prairie – yielded the result (Table 4.2) of 1.75 million oven dry tons of both agricultural and forestry residues. Assumptions and other details regarding calculations can be found on the BIMAT website. As with any tool, limitations exist and additional research is required.

"The BIMAT program seems to be a fairly good source of very general data. Zoomed-in images of forestry volumes are a good indication of the general info, but not specifics. They appear representative, but I don't think specific planning can be done with this information. A business plan/proposal would have to get into the specifics. With a quick review of the BIMAT and MLI sites, in my opinion, these towns do not offer the needed proximity of forest volume for a smaller scale woody biomass project as they have a wide radius of agricultural development."[30]

[29] Agriculture Canada: http://www4.agr.gc.ca/AAFC-AAC/display-afficher.do?id=1226509218872&lang=eng
[30] Rebecca McKay, Manitoba Conservation Forestry comments – MAFRI 29/10/09

Table 4.2: Biomass Inventory Calculation (BIMAT)[31]





[31] Agriculture Canada: BIMAT Tool Analysis http://www4.agr.gc.ca/AAFC-AAC/display-afficher.do?id=1226509218872&lang=eng

4.2 Agricultural Feedstocks

According to Manitoba Agriculture, Food and Rural Initiative (MAFRI), Manitoba grows a total of nine major crops (in order of number of acres farmed): canola; wheat; oats; barley; soybeans; flax; corn; sunflowers; beans; and field peas. The 8.2 million acres planted in 2007-08 yielded over 10 million tonnes of grain, and over 12 million tonnes of agricultural residue. The amount of residue which can be taken from the land varies by a number of factors including: conservation; type of crop; location of land; fertility of soil; and farmer preference.

The energy value of these residues varies between 16 and 24 MJ/kg (7,000-10,000 Btu/lb) with the majority between 16 and 18 MJ/kg using moisture rates of between 6 and 12%. Additional information regarding the chemical composition of each residue and its proximate analysis is available at the ECN Phyllis Database (Table 4.3). A sample set of data is displayed for wheat straw.

Table 4.3: Phyllis Database Results for Wheat Straw[32]

Glossary	
daf	dry ash free
ar	as received
Msr	Measured
Lim	detection Limit
Cal	Calculated
ND	Not Determined
Unk	Unknown
Avg	Average
Sst	van Soest
Sgr	Sugar Analysis

Sample information	
Group	straw (stalk/cob/ear)
Subgroup	wheat
Material	wheat straw, pellets
ID-number	972
Reference:	ECN laboratories.
Remarks:	tested in ECN BFB gasifier (WOB)

Material composition

Proximate analysis (wt. %)	dry	daf	ar
Ash	7.1		6.3
Water			11.1
Volatiles	74.9	80.6	66.6

Calorific value (kJ/kg)	dry	daf	ar
HHV	18490	19903	16438
LHV	17189	18503	15010
HHV_{Milne}	18537	19954	16480

Ultimate analysis (wt. %)	dry	daf	ar	
C	45.8	49.3	40.7	Msr
H	5.96	6.4	5.3	Msr
O	40.1	43.2	35.7	Cal
N	0.45	0.48	0.4	Msr
S	0.16	0.17	0.14	Msr
Cl	0.4	0.431	0.356	Msr
F	0.001	0.001	0.001	Lim
Br	-	-	-	ND
Total:	100	100	100	

[32] ECN Phyllis Database: http://www.ecn.nl/phyllis/search.asp

Information on the total agricultural residues in Manitoba has been gleaned from a number of sources including: Province of Manitoba; Studies from the Prairie Practitioners Group and Tyrchniewicz Consulting; Manitoba Hydro; Bioweb; Energy Research Centre of the Netherlands; Purdue University and others (Tables 4.4 and 4.5). No single source provided all the information necessary to fill the table, and the information provides a good overall picture of the agricultural biomass in Manitoba. The data is displayed for each crop residue (excluding beans and field peas due to low total yields), and subdivided for different types of residues.

Although the data presents a clear picture of plentiful agricultural biomass, the following considerations need to be taken into account with the use of this resource:

- Some residues (e.g. canola, barley, flax, bean and oat straw) are not typically baled, and have not been considered in other estimates of Manitoba's biomass inventory. However the reason canola and other types of straw are not removed are because of the reasons mentioned above (fertility, location, preference) in addition to the fact that no market for this straw exists[33]. In fact much of the straw of any crop can be baled and sold given that the right conditions exist – both in terms of conservation and markets. Other factors to be considered in the collection of crop residues are the density of the straw per acre, how well it can be swathed, and how much soil will be picked up when the straw is baled.
- Soil fertility varies across the province, resulting in different requirements for the retention of crop residues
- Farmer preference varies as well, with some farmers burning it off while others in the same area will protect it to maintain fertility and tilth
- Economic considerations play a role as well – if the price of fertilizer is low, there is less pressure to retain crop residues
- Livestock bedding requires a percentage of the straw grown in Manitoba of between 1 and 1.5 million tonnes per year[34]
- Location of the biomass is critical to the economics of any venture needing to access this resource, and may not viably include all areas of Manitoba.

The information presented below on biomass grown in Manitoba (Table 4.4) includes data on the top eight crops in the Province. Straw to grain ratios vary from 3:1 for sunflowers to a low of 1:1 for canola and corn. The amount of acreage covered by the various crops range widely with canola and wheat covering over half the ground planted, accounting for roughly equal proportions of straw and grain. Conversations with farmers and MAFRI confirmed that canola straw (and other types), although not generally cut and baled now, did represent a potential and largely untapped biomass opportunity.

Wheat straw, although grown on the same amount of acres as canola, produces far more biomass per acre, and is the largest agricultural biomass resource. The total tonnage of straw which could be available from these crops (for the year spanning 2007-2008) was 12.7 million tonnes, with 4.2 million representing one third of that amount as a sustainable annual harvestable residue.

To put this into perspective, Manitoba Hydro's total natural gas imports in 2007 (heating purposes) were 63.0 PJ [35], and with coal and propane the total energy used from fossil

[33] Eric Liu – MAFRI Nov 2009
[34] Eric Liu – MAFRI Nov 2009
[35] Manitoba Hydro: http://www.hydro.mb.ca/corporate/ar/2007/AR_0708.pdf

fuels was 71.7 PJ (64.5PJ @ 90% efficiency). Using an estimate of 90% seasonal efficiency in the use of 33% of the available agricultural biomass (4.2 million tonnes – Table 4.4), the resulting 64.2 PJ (Table 4.5) could provide all of the heat energy now supplied by fossil fuels in Manitoba.

Table 4.4: Agriculture Biomass Sources and Energy Yields (2007-08)

Crop Residue	Ratio straw to grain	Lb/bushel	Ave bushels per acre	Tons straw per acre	Acres	Short tons straw	Tonnes straw	Net tonnes straw (1/3 of total)
								33%
Column	A	B	C	D	E	F	G	H
Canola	1	50	40.1	1.00	2,878,521	2,885,717	2,617,923	862,867
Wheat	1.3	60	54.3	2.12	2,844,740	6,024,306	5,465,250	1,801,347
Oats	1.4	32	102.0	2.28	724,064	1,654,341	1,500,819	494,670
Barley	1.5	48	71.2	2.56	655,225	1,679,473	1,523,618	502,184
Soybeans	1.5	60	33.4	1.50	303,709	456,475	414,114	136,492
Flax	2	60	25.0	1.50	252,980	379,470	344,255	113,467
Corn	1	56	120.0	3.36	168,616	566,550	513,974	169,406
Sunflower	3	28	56.0	2.35	164,082	386,167	350,331	115,469
TOTALS					7,991,937	14,032,499	12,730,283	4,195,901

Notes: http://bioweb.sungrant.org/, http://www.hort.purdue.edu/newcrop/afcm/canola.html , http://www1.agric.gov.ab.ca/$department/deptdocs.nsf/all/eng3127 , http://www.reap-canada.com/online_library/feedstock_biomass/Assessing%20the%20Agri-Fibre%20Biomass%20Residue....%20(Bailey-Stamler%20et%20al.,%202007).pdf http://bioweb.sungrant.org/ , http://www.cyberspaceag.com/kansascrops/whatsinabushel.htm, http://www.unc.edu/~rowlett/units/scales/bushels.html http://www.mmpp.com/mmpp.nsf/ym_2009_10_yield_data.pdf

More information on Manitoba biomass and extensive detail on the location of the biomass by Rural Municipality can be found in MAFRI's Straw Procurement Study.

The energy value of the biomass is shown in Table 4.5 which begins where Table 4.4 left off (Column I – Net tonnes straw). Columns J and K (Lower Heating Value - LHV) are the same with only differences in types of units, and Column L is the Higher Heating Value (HHV) for the same material. Column M is the energy content of the straw (at LHV) with column N showing the tonnes of that particular biomass it takes to generate one petajoule (PJ) of energy. Columns O through Q show the total PJ available given a variety of seasonal efficiencies (50, 70 and 90) based on the one-third of the total tonnage calculated in column I.

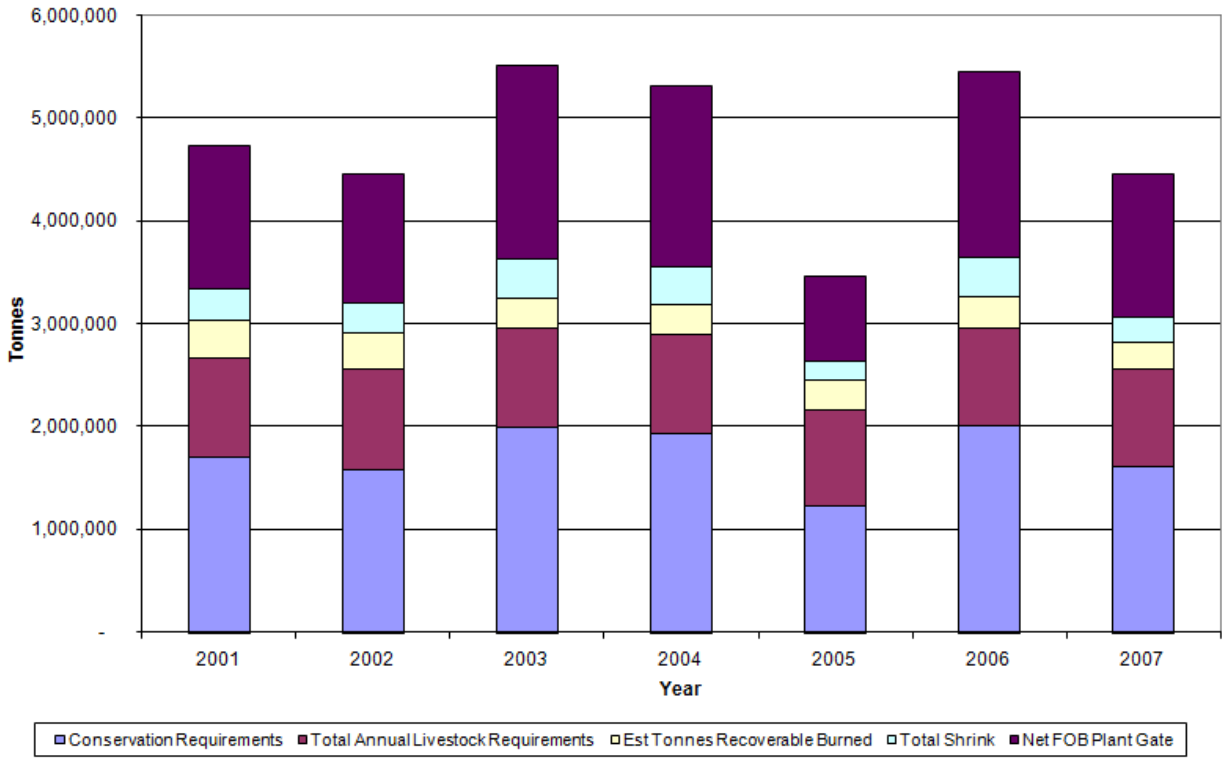
Table 4.5: Agricultural Biomass Energy Value (2007-08 data)

Crop Residue	Net tonnes straw (1/3 of total)	KJ/kg	Btu/lb	KJ/kg	Total PJ	Tonnes biomass per PJ	Efficiencies		
	33%	LHV	LHV	HHV	LHV		50%	70%	90%
Column	I	J	K	L	M	N	O	P	Q
Canola	862,867	16,791	7,269	18,100	14.5	59,556	7.24	10.14	13.04
Wheat	1,801,347	15,983	6,919	17,100	28.8	62,566	14.40	20.15	25.91
Oats	494,670	17,011	7,364	18,089	8.4	58,785	4.21	5.89	7.57
Barley	502,184	17,563	7,603	18,780	8.8	56,938	4.41	6.17	7.94
Soybeans	136,492	20,887	9,042	NA	2.9	47,877	1.43	2.00	2.57
Flax	113,467	18,709	8,099	20,040	2.1	53,450	1.06	1.49	1.91
Corn	169,406	18,101	7,836	16,849	3.1	55,246	1.53	2.15	2.76
Sunflower	115,469	24,351	10,542	25,948	2.8	41,066	1.41	1.97	2.53
TOTALS	**4,195,901**				**71.37**		**35.68**	**49.96**	**64.23**

Notes: http://www.ecn.nl/phyllis/

A summary of the provincial uses of wheat straw has been developed by Prairie Practitioners Group (PPG) and is presented below in Figure 4.2. The total (around 5 million tonnes) is in the range of the data presented in Table 4.4 (column G – wheat straw). As surmised above, PPG has estimated around 30% of the straw being available for needs other than conservation, livestock, burned or shrink.

Figure 4.2: Manitoba Provincial Uses of Wheat Straw[36]



A spreadsheet modeling tool for wheat straw has been developed by PPG (for MAFRI) and is in the process of being verified and tested. An example of the kind of output available from this tool is shown below in Table 4.6.

Table 4.6: Sample Information from Straw Procurement Study[37]

YEAR	Municipality	Risk Territory	Census Ag Region	Census Ag District	Acres	Yield per acre (Metric	# Producers	Grain Yield Tonnes	% Un-insured / Not Reported	Biomass to Straw Ratio	Total Bio-Mass	
2001	GRAHAMDALE	15	12	18	1,721.00	1.079 tonnes	1	1,857	10%	1.3	2,682	tonnes
2001	GRANDVIEW	9	6	17	51,745.00	1.105 tonnes	151	57,170	10%	1.3	82,591	tonnes
2001	GREY	12	7	9	41,235.00	0.706 tonnes	97	29,112	10%	1.3	42,051	tonnes
2001	HAMIOTA	6	3	15	36,794.00	1.014 tonnes	105	37,309	10%	1.3	53,891	tonnes
2001	HANOVER	11	9	2	16,092.00	0.559 tonnes	58	8,995	10%	1.3	12,993	tonnes
2001	HARRISON	6	3	15	18,629.00	0.923 tonnes	73	17,195	10%	1.3	24,837	tonnes
2001	HEADINGLY	12	9	11	5,428.00	0.59 tonnes	19	3,203	10%	1.3	4,626	tonnes
2001	HILLSBURG	9	4	16	6,511.00	1.112 tonnes	24	7,240	10%	1.3	10,458	tonnes
2001	KELSEY				18,206.00	1.248 tonnes	36	22,721	10%	1.3	32,819	tonnes
2001	LA BROQUERIE	14	9	2	305	0.758 tonnes	4	231	10%	1.3	334	tonnes
2001	LAC DU BONNET	14	1	10	15,256.00	0.644 tonnes	48	9,825	10%	1.3	14,191	tonnes

[36] Prairie Practitioners Group (MAFRI): Manitoba Straw Study 2008
[37] Prairie Practitioners Group (MAFRI): Straw Procurement Study – Spreadsheet Tool 2008

Information on individual producers and suppliers of straw and straw bales can also be found on the Manitoba Agriculture website[38].

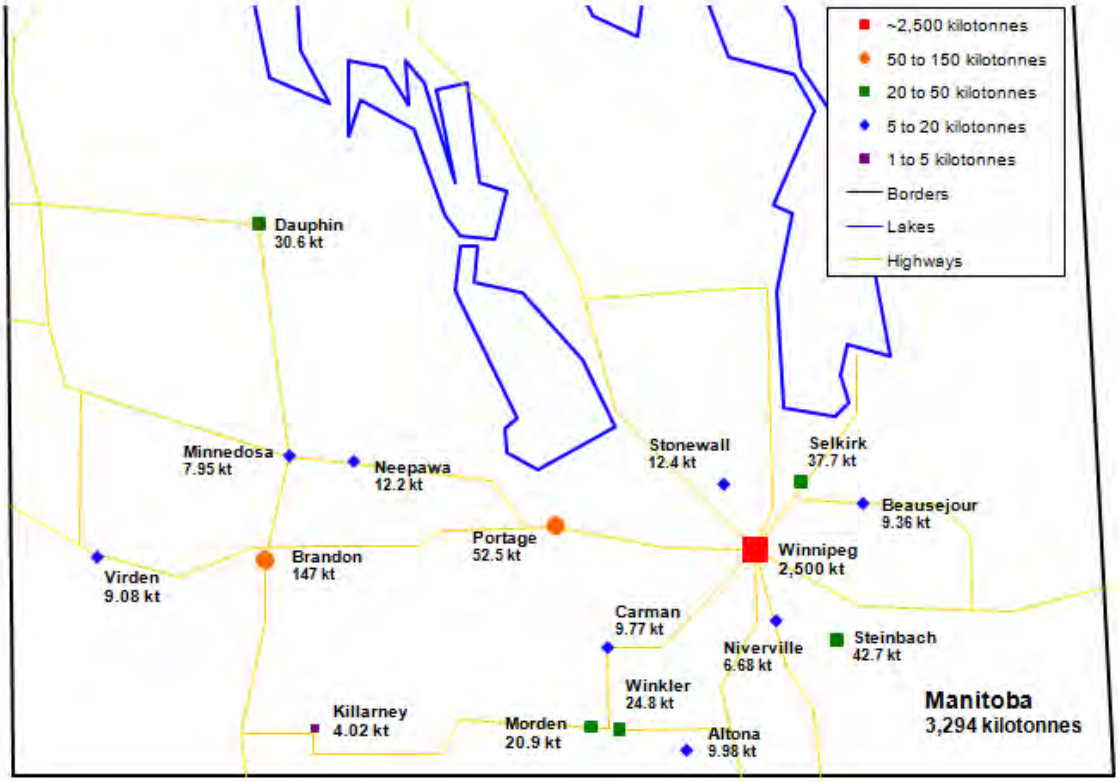
Not included in the information in this section is hemp, hemp hurds, or hemp straw. Inquiries are still out, but at the time of this writing no precise information is available on the amount of hemp biomass in Manitoba. In addition, like most materials, burning hemp straw with its valuable fibre content makes little sense, and its use as a biomass fuel will depend on market conditions.

Biomass residues from Manitoba's agricultural processing industry are considered in Section 4.4 below.

Heat Map

A heat map, created by Manitoba Hydro provides an idea of what level of biomass would be required for large scale heating use in Manitoba per urban/rural centre. The total amount of straw required to displace natural gas in commercial and residential applications is 3.3 million tonnes of straw, less than the 5 million tonnes available from wheat straw alone (Figure 4.3).

Figure 4.3: Straw Required to Displace Natural Gas in Commercial and Residential Applications[39]



[38] Manitoba Government: http://www.gov.mb.ca/agriculture/crops/forages/bjf01s04.html.
[39] Manitoba Hydro: Heat Map developed by Jeremy Langner

4.2.1 Agricultural Fuel Crops

New fuel crops being developed provide an important potential option to the present agricultural crop/biomass paradigm in which the residues of harvest (secondary land use) are used after the grain is harvested (primary land use). Instead, fuel crops are planted to be harvested only for their energy value and include crops like switch grass and miscanthus whose fuel value per kilogram is not significantly more than the 16-20 MJ/kg noted on Table 4.5. What is different, however, is the tonnage available per hectare.

"(CERES) reported that yield results from its nation-wide network of field trials showed that average biomass yields among switchgrass seed varieties tested last season were as much as 50% more than the government's projected yields for 2022. Proprietary varieties sold under the company's Blade Energy Crops brand were consistently the highest yielding varieties across multiple trial locations, with average yields nearly 10 tons.

"The highest yield was reported in California, where a Ceres experimental variety produced 19 tons per acre ,,, (and) have a significant impact on farm and conversion economics, and can dramatically reduce harvest and delivery costs per ton, collectively the single largest expense in providing raw materials to bioenergy facilities. Similar benefits would be seen in calculating the greenhouse gas savings of displacing petroleum with biofuels made from dedicated energy crops.

"… More recently, a highly regarded biofuel study co-authored by Sandia National Labs used a conservative six tons of biomass per acre for energy grasses — similar to estimates by the U.S. Environmental Protection Agency (EPA)."[40]

Using the six ton figure, switchgrass could yield up to **3 times more than wheat straw per acre**, potentially providing an option to growing grain – depending of course on the price of biomass. Important to note as well is that CERES has only tested its seed as far north as South Dakota, and crop yields are highly dependent on latitude, growing days, soil conditions and precipitation.

Conclusions:
The use of agricultural biomass as a feedstock for thermal conversion is attractive given the amount of biomass available in Manitoba. As shown in the data, Manitoba could displace most of its natural gas use with a third of its annual agricultural biomass crop (64.2 PJ assuming 90% seasonal efficiency). While being highly dependent on where and when this biomass is available, this quantity of biomass can be derived not only from wheat straw but from other crop residues as well, depending on market and conservation requirements. These conclusions do not, however, include the majority of agricultural biomass now being used by Manitoba's thermal applications – that being biomass residues from processing facilities – considered in Section 4.4. Dedication of land to producing fuel crops is certainly an option to consider, and has the capability of producing up to three times the biomass of present crop residues.

[40] CERES: http://www.ceres.net/News/NewsReleases/2009/05-20-09-News-Rel.html

4.3 Forestry Feedstocks

Biomass from different sources not only has different energy values, moisture and handling characteristics, but also has a number of different traits including: time to market; accessibility; size of landholding; and number of contractors required to plant, tend and harvest the biomass. Forestry biomass has an entirely different lifecycle than agricultural biomass and has traditionally been managed by large corporations, which in Manitoba are Tembec, Tolko, and Louisiana Pacific.

"Manitoba is not a major primary forestry jurisdiction compared to other northern regions of similar size, but it remains a desirable destination for secondary forest product development. Of Manitoba's forested lands, about 94% are owned by the province, 1% is owned by the federal government and the remaining 5% is privately owned. The annual allowable harvest limit for timber on Manitoba's Open Crown Lands is just under 8.9 million cubic meters, while the actual harvest in 1996 was 2.1 million cubic metres (2.2 million in 2007-08)*, on 15,342 hectares of land."*[41]

"Manitoba's current forest tenure system is based on the following components:

- *Provision of long-term forest management license agreements (FMLAs) to forestry companies for large tracts of forest lands (FMLs). These agreements include guarantees for fibre access, or annual allowable cut for the company within the license area. The company must fulfill the license agreement, file forest management plans, and acquire environmental licenses for its mills and woodland operations.*
- *Provision of annual 'quota' timber harvesting rights to individual entities (individuals and/or companies) within specified tracts of lands. The province manages the forests where quota holders operate outside FML boundaries. The company manages the forest, and the quota holder arrangements inside FML boundaries.*

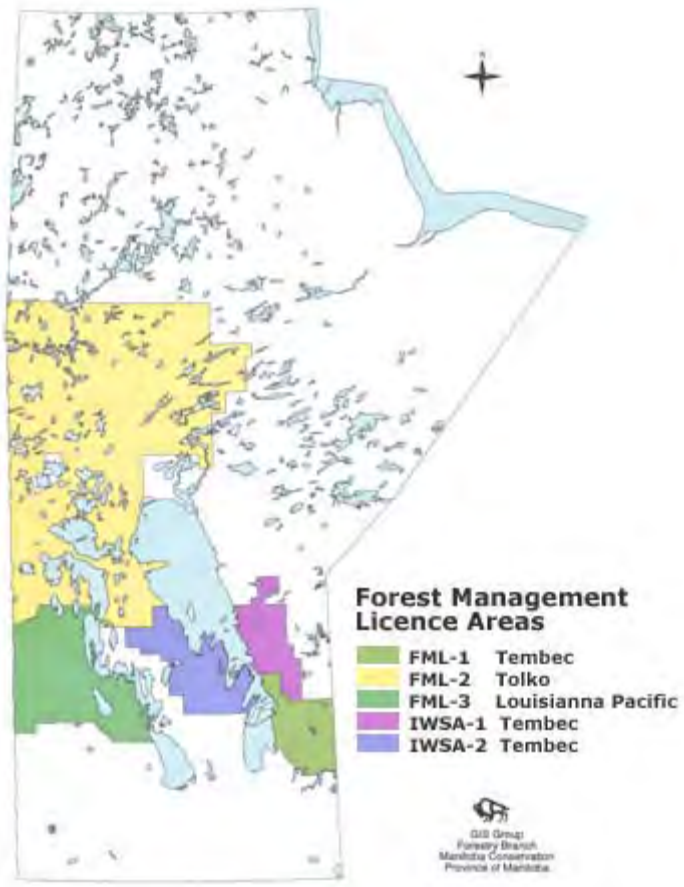
"In addition to these two main tenure forms, Manitoba has provisions for short-term timber allocations:

- *Provision of special allocations (fixed term - agreements with First Nations)*
- *Provision of timber sales (single year sales without competition)*
- *Provision of timber auctions (single year)*
- *Provision of timber permits (less than 300 cubic meters where the permittee intends to sell; less than 100 cubic meters where the permittee intends for personal use - one year max)*

"There are also private woodlots that are not managed by the province. These may be part of a forest management plan, especially where Louisiana Pacific operates in Manitoba."[42]

[41] Manitoba Conservation Forestry Branch: http://www.gov.mb.ca/conservation/forestry/forest-industry/i-intro.html
[42] Manitoba Wildlands: http://www.manitobawildlands.org/forests_mb_ind.htm

Figure 4.4: Manitoba Forest Management Licence Holders[43]



A study done recently by Price Waterhouse Coopers in 2009 for Manitoba Conservation provides significant detail on the topic of our provincial forest biomass, with information on all aspects pertaining to its use. A few key conclusions (more can be found in the study itself) are as follows: [44]

[43] Manitoba Conservation Forestry Branch: http://www.gov.mb.ca/conservation/forestry/forest-practices/planning/fpp-fmlsandcrown.html
[44] PricewaterhouseCoopers, "Manitoba Wood Biomass for Heating and Energy Feasibility Study" March 31, 2009

- From a woody biomass perspective, there is enough standing biomass available in many areas of the Province to undertake large scale bioenergy projects provided the economics justify the opportunity. From a geographic perspective, many of the opportunities lie outside of the wood basket of the big three companies in the Province but there also may be some opportunity for underutilized species in these regions.
- Many of the opportunities to access standing biomass are in areas where logging infrastructure, including physical infrastructure (i.e. roads and facilities) and capacity (i.e. logging equipment and personnel) are limited.
- There may exist a moderate volume (up to 300,000 cubic metres) of logging residuals throughout the Province but current regulations inhibit the utilization of most of this volume.
- Relatively small volumes of sawmill residuals exist in the Province with no changes anticipated until markets improve and sawmills resume production.
- An opportunity both to create new woody biomass supply as well as potential carbon credits exists in the agricultural areas of the Province. This opportunity deserves more study and the success of test sites should be closely monitored.
- If Manitoba is going to modify its current forest operations to increase the volume of woody biomass extracted, Manitoba Conservation should initiate a process to create guidelines or regulations covering biomass harvesting.
- There should be recognition that Aboriginal Communities in the Province will play a key role in the emerging biomass economy and efforts should be made to elicit their participation in a meaningful and economically viable manner.

According to Manitoba Conservation, the total forestry biomass in Manitoba is 535,000,000 m^3 (Table 4.7) which includes: Provincial Forest; Forests and Parks; all Forest Management Licences; and forested Agriculture Coded land. This does not include Federal, Municipal, Private, or Indian Reserve land.[45]

The energy value of this biomass, if completely utilized, would amount to 2,140 PJ (column G), which is clearly neither possible nor sustainable, but useful to know in understanding the wider biomass picture in Manitoba. Historically the best economic use of these resources has been lumber and pulp/paper, however future scenarios may place the fuel value of wood higher than these traditional uses. If 2% of the total forestry biomass inventory were to be used for heating purposes, it could deliver 42.8 PJ (38.5 PJ @ 90% efficiency), or around half of Manitoba's annual heating needs.

Table 4.7: Total Manitoba Forestry Biomass[46]

Feedstock	Annual Volume	Mass per m3	Amount Available	Energy Value	Potential Utilization	Potential Energy (100%)
	m^3	kg	tonnes	kJ/kg	%	PJ
Column	A	B	C	E	F	G
Total Forestry Biomass	535,000,000	400	214,000,000	10,000	100%	2,140
Total AAC	8,900,000	400	3,560,000	10,000	100%	35.60
Allocated AAC - FML	4,221,000	400	1,688,400	10,000	100%	16.88
Sample Scenario	535,000,000	400	214,000,000	10,000	2%	42.80

[45] Interview with Manitoba Conservation Forestry Branch: 29/10/09
[46] Information from Manitoba Conservation Forestry Branch: 2009

The Annual Allowable Cut (AAC) is 8.9 million cubic meters (m^3), and of that amount 4.2 million m^3 (Table 4.8) is allocated primarily to the three large forest companies operating in Manitoba.

Table 4.8: Summary of Manitoba Tenures[47]

Forest Management License Agreements	AAC Volume Allocated (m^3)	Species
FML#1 & 2	2,030,160	Spruce, Pine, Fir
FML#3	900,000	Poplar, Aspen, Birch
Quota Holders	591,333	SW (467,241 m^3) & HW (124,092 m^3)
IWSA	293,960	SW (225,410 m^3) & HW (68,550 m^3)
MFS – Overlap with FML 23 and 31	405,560	SW (261,480 m^3) & HW (144,080 m^3)
Total Volume	4,221,013	SW (261,480 m^3) & HW (144,080 m^3)

The Manitoba forest harvest residuals are estimated in Table 4.9, showing a total of 2.5 million cubic meters of merchantable harvest with a corresponding 286,839 cubic meters of top, foliage and branches.

Table 4.9: Estimate of Gross Available Harvest Residuals for 2007-08 Period[48]

			Harvest Residual Removal (m^3)			
Total Theoretical Biomass Harvest	%*	m^3	100%	75%	50%	25%
Merchantable Harvest	87	2,206,450				
Top, Foliage, Branches	13	286,839	286,839	215,129	143,419	71,710
Total	**100**	**2,493,289**				

*Manitoba Conservation Estimate of 15% logging residuals vs. total harvest volume

Details regarding the unallocated fibre, allocated undercut, forestry related residuals, and wood waste are contained in Table 4.10, providing a total of over 4.5 million m3 which could theoretically be available for heating purposes. As pointed out in Table 4.9, the unallocated fibre is located largely in remote regions of Manitoba with projected delivery costs exceeding fibre income in currently utilized areas of the province. Both the allocated undercut and logging residuals amounting to over 1.5 million m3 are projected to be economically usable depending on favourable market conditions. Sawmill residues

[47] PricewaterhouseCoopers (Manitoba Conservation), "Manitoba Wood Biomass for Heating and Energy Feasibility Study" March 2009, p. 15.
[48] PricewaterhouseCoopers (Manitoba Conservation), "Manitoba Wood Biomass for Heating and Energy Feasibility Study" March 2009, p. 22.

are small and well utilized and wood waste is shown to be used in Winnipeg (incomplete information), but not in the remainder of the province.

Table 4.10: Manitoba Forestry Biomass[49]

Source	Potential Annual Volume	Current Utilization	Approximate Delivered Cost	Issues
Unallocated fibre	Up to 2,750,000 m^3	None	\$45/m^3 including stumpage – whole tree chipping	Fibre in more remote regions of MB, road building and other costs may be slightly higher than in currently utilized areas of MB. The delivered cost of any fibre depends largely on distance to facility and costs of equipment and labor in the region. The approximate delivered cost of unallocated fibre is based on the average logging costs and haul distance in the Province. With the current facilities in the Province, delivered log costs of most unallocated fibre would exceed this figure.
Allocated undercut	1,300,000 m^3	None	\$40/ m^3 including stumpage – tree length	Lowest chance wood for current large tenure holders, may become economic if prices dictate
Logging residuals	286,000 m^3	Approximately 10%	\$30/ m^3 not including stumpage	These residuals would not be economic under tree length harvest system
Sawmill residuals	Chips – 47,000 BDU's – 133,301 m^3 * Sawdust & Hog Fuel – 36,000 BDU's – 101,309 m^3	Approximately 80%	\$50/BDU <\$10/BDU – cost recovery for handling	Current utilization is high due to low sawmill output
Urban wood waste (Winnipeg only)	3,500 tonnes annually	100%	No Cost	All volume is being consumed or disposed of by Anchor Wood – instead of being landfilled, the volume is being delivered to a location adjacent to the landfill and they use or dispose of it there.
Urban and rural wood waste in MB outside of Winnipeg	6,500 tonnes annually	0%	No Cost	Widely dispersed – forest health concerns due to DED

* – 1 BDU = 2.83 m^3 – Collection and transport would be a cost but would vary based on scenario

[49] PricewaterhouseCoopers (Manitoba Conservation), "Manitoba Wood Biomass for Heating and Energy Feasibility Study" March, 2009, p. 37.

In order to determine the energy potential of the biomass in Table 4.10, the figures from that table have been transposed to Table 4.11 (columns A and D). Based on information from Manitoba Conservation, the volumetric mass and energy values were assigned, resulting in Column H – Present Energy Value totaling 0.48 PJ. Column I in Table 4.11 makes some modest projections to:

- increase the use of unallocated fibre and allocated undercut from 0% to 10%
- increase the use of logging residuals from 10% to 30%
- increase the use of sawmill residuals – chips from 10% to30% and sawdust/hogfuel from 80% to 90%
- increase the use of non-Winnipeg urban and rural wood waste from 0% to 50%.

With these changes, the projected amount of forestry biomass available for heat increases from 0.5 PJ (Column H) to 2.2 PJ (@ 90% efficiency – Column N).

Table 4.11: Manitoba Potential Sources of Wood Biomass

Feedstock	Annual Volume	Mass per m3	Amount Available	Current Utilization	Utilized 2007-08	Energy Value	Present Energy Value (@90% eff)	Potential Utilization	Potential Utilization	Potential Energy (100%)	PJ @ Annual Thermal Efficiencies		
	m^3	kg	tonnes	%	tonnes	kJ/kg	PJ	%	tonnes	PJ	50%	70%	90%
Column	A	B	C	D	E	G	H	I	J	K	L	M	N
Unallocated Fibre	2,750,000	350	962,500	0%		10,000	-	10%	96,250	0.96	0.48	0.67	0.87
Allocated Undercut	1,300,000	450	585,000	0%		10,000	-	10%	58,500	0.59	0.29	0.41	0.53
Logging Residuals	286,000	400	114,400	10%	11,440	7,000	0.07	30%	34,320	0.24	0.12	0.17	0.22
Sawmill Residuals - Chips	133,301	350	46,655	10%	4,666	12,000	0.05	30%	13,997	0.17	0.08	0.12	0.15
Sawdust & Hogfuel	101,309	350	35,458	80%	28,367	12,000	0.31	90%	31,912	0.38	0.19	0.27	0.34
Winnipeg			3,500	100%	3,500	16,000	0.05	100%	3,500	0.06	0.03	0.04	0.05
Other Urban and Rural			6,500	0%	-	16,000	-	50%	3,250	0.05	0.03	0.04	0.05
TOTAL	**4,570,610**		**1,754,014**		**47,972**		**0.48**		**241,729**	**2.45**	**1.22**	**1.71**	**2.20**

Sources: Manitoba Conservation Forestry Branch, PricewaterhouseCoopers, "Manitoba Wood Biomass for Heating and Energy Feasibility Study" March 31, 2009 (Table 9)

4.3.1 Forestry Fuel Crops

The following section was developed by PricewaterhouseCoopers in their March 2009 biomass study for Manitoba Conservation Forestry Branch regarding forestry fuel crops.[50]

1. **High Yield Afforestation**

   This group consists of hybrid poplar, aspen and willow cultivars designed to meet yields of 13.6-20.0 gross cubic metres MAI (mean annual increment) or 5 - 7.4 odt (oven dried tonnes) ha-1 y-1 of woody biomass (above ground). These cultivars, under intensive management regimes, are being established on moderate to high quality, lands across Canada and qualify as either afforestation or reforestation under the Kyoto Protocol definition, which qualify for carbon credits. CFS has done extensive growth and financial analysis of the opportunity and identified candidate areas across the country. Manitoba has 75,308 km^2 of potential candidate areas, at least 40,000 km^2 of which are considered high quality sites.

2. **Concentrated Woody Biomass Plantations**

   This group consists of short-rotation (3-5 yr), high-yield biomass plantations that use high density designs (15-20,000 stems per hectare). These plantations are being established on moderate to high quality lands across Canada to establish feedstock for energy conversion. Various cultivars of hybrid willow (Salix spp.) and hybrid poplar (Populus spp.) are being established under intensive management regimes to maximize establishment efficiency and biomass production. Initially, cultivar eco-site suitability and management practices development will be the primary focus on all demonstration study sites.

Both of these sources have the potential to increase the availability of woody fibre for both pulp and biomass energy production while also earning valuable carbon offset credits which may make these projects more appealing. More work is required to demonstrate the economics, but the option of growing woody biomass crops on lands currently associated with agriculture should be considered and further research should be undertaken.

Conclusions

Manitoba's forestry biomass resource is significant with a total of 535 million m^3 (2,140 PJ) and an annual allowable cut of 8.3 million m^3. As noted by PWC, much of this resource is located beyond developed areas and roads making full utilization difficult and economically challenging. Of the 4.2 million m^3 allocated to the FML holders, half of that was used as lumber this past year, with around 15% as recoverable residues.

As burning forestry biomass represents the last and perhaps least valuable way to convert it to a marketable commodity, very little of this resource is best used as a thermal resource based on traditional lumber, paper/pulp paradigms. Consequently, although a large amount, the biomass contained in Manitoba's forests does not represent a significant resource for thermal conversion, unless market conditions change and conversion of wood and wood residues to heat becomes a profitable activity.

The logging and sawmill residues (over 520,000 m^3) do represent a resource which can supply biomass for heating purposes, but a majority of this amount (logging residues) are traditionally left in or near the logging location. Use of these residues for heating would require a significant change in how this resource is managed.

[50] PricewaterhouseCoopers (Manitoba Conservation), "Manitoba Wood Biomass for Heating and Energy Feasibility Study" March 2009, p 24

Of note is a difference between the numbers presented in the tables above, the numbers available using BIMAT for urban wood waste. According to this resource, a 10 km radius from the centre of Winnipeg yielded nearly 120,000 tonnes of urban wood waste – a figure 18 times more than that estimated above (6,500 tonnes).

Fuel Crop implications

Regarding the potential fuel crops, PWC stated that per hectare, these crops could yield 5 – 7.4 odt / hectare per year. PWC explored a scenario using 40,000 square km of land to grow wood for fuel, which would yield an average of 20 million odt per year. At 15 MJ/kg, this amount of biomass could generate 270 PJ (@90% efficiency); more than four times more than the projected agricultural biomass figure. This figure is tempered by the fact that the land selected for use may be difficult to access, with no specificity placed on the location.

The implications of even a portion of this biomass production are immense. Forestry fuel crops can yield far more than all the combined agricultural biomass in the province, able to take care not only of Manitoba's heating needs but have biomass left over for export.

4.4 Agriculture Biomass Feedstock Processing and Logistics

4.4.1 Agriculture Biomass Processors

The information presented in this section (*italicized)* has been prepared, by Prairie Practitioners Group in a study prepared for Manitoba Agriculture, Food and Rural Initiatives in March 2009.

Flax Shives

> *"The Schweitzer-Mauduit flax straw processing operation, based at Carman, is the sole source of flax shives in Manitoba at this time. From this operation, 60,000 to 70,000 tonnes of flax shives are produced on an annual basis. The Canadian fiber processing operations are based in Winkler, Manitoba, Canada. Flax straw is purchased across a broad area including the Canadian provinces of Manitoba, Saskatchewan and North Dakota in the United States. The straw is baled into round bales and trucked to 3 different processing locations in Southern Manitoba.*

Oats Hulls

> *"The Can-Oat Milling plant at Portage la Prairie processes oats for the food markets in the USA and Canada. At least 40,000 tonnes of oat hulls (ground and pelleted) are produced annually. Can-Oat Milling, a division of Viterra, is the largest industrial supplier of oat products in the world, with production capacity of over 500 million pounds of oat products per year. Can-Oats operates three oat milling facilities strategically located in the heart of the best oat growing region in North America.*
>
> *"Emerson Milling is a privately owned oat milling plant located in the heart of the Red River Valley on the Canada / US border. The company markets oat products*

for use in birdfood, small pets, and animal feed rations. This operation produces about 8,500 tonnes of oat hulls annually for bird food and livestock feed markets.

Sunflower Seed Hulls

"Keystone Grain at Winkler processes sunflower seeds for the export and domestic markets. Their products include oilseeds and bird feed. From their processing they produce 8,000 to 10,000 tonnes of sunflower hulls annually. Keystone Grain also specializes in commodities such as flaxseed, sunflower kernel, white millet, red millet, canary seed and other special crops.

"Nestibo Agra Commodity Processors Inc. at Deloraine processes sunflower seeds for both the in-shell and dehulled markets. A significant proportion of their production is exported. They produce 1,500 to 2,000 tonnes of sunflower hulls annually.

"Prairie Sun Seeds at Souris process sunflower seeds mainly for export in the shell but dehull some for the bird food market. They produce about 1,500 tonnes of sunflower hulls annually.

Hemp Hurds

"The Emerson Hemp Distribution Company at Emerson is in the developmental stage. When the plant is operating, it processes about 2 tonnes of raw fibre per hour. Approximately 70% of a hemp stalk is hurd. Currently, their market for hemp hurds is for animal bedding and nesting material, but future uses could include additives in concrete and highly absorbent products. In the processing of the hemp hurds, 10 to 20% is a residue which could be made available for other uses such as biofuel products.

(Note: Other suppliers of hemp biomass products include: Manitoba Harvest, Parkland Industrial Hemp Growers Coop, Individual producers for Hemp Oil Canada Inc., Individual producers for Farm Genesis Group at Waskada, and Coldstream Alfalfa Processing.)

"To provide an example of the potential quantities of hemp hurd which could be available consider the individual producers who contract with Manitoba Harvest – Hemp Foods and Oils. If the 4,000 acres of hemp which is contracted produces 4 tonnes of hemp straw per acre then 16,000 tonnes of hemp straw would be produced. If the straw is 70% hurd then 11,200 tonnes of hurd would be available. If 20% of the hurd is a lower value residue then 2240 tonnes would potentially be available to the solid biofuel market." [51]

Wheat Straw

The processing of wheat straw as a fuel for combustion in Manitoba is limited at this point to baling; however no commercial combustion of these bales for heat generation is occurring. Wheat straw pelletizing, cubing and other densification methods are in the development and deployment stage.

[51] Prairie Practitioners Group (MAFRI): "Biomass Conversion Feasibility Study Supplier Analysis" March 2009, p. 4-12

4.4.2 Agricultural Biomass Densification

The following analysis and summary of agricultural residue densification was created by the Prairie Practitioners Group on behalf of MAFRI in their Biomass Conversion Feasibility Study Supplier Analysis, 2009.

Summary:

- *"An increased bulk density (from 80-150 to 600-700 kg/m3), resulting in lower transportation costs, reduced storage volume and easier handling.*
- *A lower moisture content (lower than 10%), favouring a long conservation and less loss of product during storage.*
- *An increased energy density and more homogeneous composition, resulting in better control possibilities and thereby higher energy efficiency and lower emissions during combustion.*

Pellets:

- *"Higher cost of production than cubes or briquettes.*
- *Need for much smaller particle size in the production of pellets as compared to cubes or briquettes. Therefore a need to grind the feedstock.*
- *More susceptible to moisture than briquettes.*
- *Silica content of agricultural residues can cause greater wear on equipment and need for replacements more often.*

Wheat Straw Pellets

- *"Grinding of straw may require two steps – first scarifying the straw and then grinding.*
- *Energy required to pelletize is usually lower than wood pelleting, because straw is delivered at a moisture content (<20%) that allows by-passing the drying stage*
- *Higher friability and the slightly lower energy content than wood pellets.*
- *High content of alkali chloride in straw which leads to high risk for corrosion and fouling in the boiler.*
- *High level of silica in straw can lead to greater abrasion in pellet plants and therefore a need to replace parts more often.*
- *High ash content of straw can lead to greater problems in combustion units.*
- *High ash content of straw can lead to more ash disposal concerns.*

Oat hull pellets

- *"Oat hulls used in combination with wheat by products provides acceptable pellet however biomass boilers require cleaning more often.*
- *Pure oat hulls are difficult to pellet without getting significant fines.*

Sunflower Hull Pellets: "Very little information available on sunflower hull pellets.

Flax shive pellets

- *"Flax shives are very abrasive and therefore do not lend themselves to pelleting.*
- *Flax shives as a feedstock are quite loose and more difficult to feed.*
- *Schools in South Dakota have experimented with burning flax pellets in their furnaces as a substitute for coal. Flax pellets co-fired coal.*
- *In these schools the shive pellets were found to burn very clean and complete with little remaining ash*

Hemp Hurd Pellets: "Very little information available on hemp hurd pellets

Cubes:

- *"Material ground in initial processing so can handle wider variations in size of feedstock material.*
- *Usually lower in cost than pelleting.*
- *Can handle agricultural residues that may be very abrasive for pelleting equipment however not as abrasive for cubing.*
- *More opportunity to blend a variety of feedstocks in producing cubes.*

Wheat straw cubes

- *"Wheat straw can be cubed in combination with other feedstock materials.*
- *Similar issues as identified for wheat straw pellets in the combustion of cubes.*

Oat hull cubes

- *"Can run into an elasticity problem with oat hulls and therefore grinding may be necessary to reduce this problem.*

Flax shive cubes

- *"PBE was producing 7/8 inch cubes from a mixture of wood, wheat straw and flax chives for use in solid fuel boiler systems to generate heat.*
- *Flax shives in combination with other biomass such as wood and wheat straw work well.*
- *Flax shives have good adhesion coefficient in relation to wheat straw and oat hulls and should enhance the durability of cubes.*
- *Flax shives have very good energy value for an agricultural residue.*

Sunflower Hull cubes: "Very little information is available on sunflower hull cubes.

Briquettes:

- *"Maintenance costs such as wear costs are lower per ton produced.*
- *Briquettes can be produced from material not acceptable for pelleting.*
- *Feedstock particle size can be larger than for pellets.*
- *Material ground in initial processing so can handle wider variations in size of feedstock material.*

Flax shive briquettes

- *"Flax shives more suitable for briquetting than pelleting.*

Oat hull briquettes: "Very little information is available for oat hull briquettes either as a single feedstock or in combination with other feedstocks.

Sunflower hull briquettes: "Very little information is available for sunflower hull briquettes either as a single feedstock or in combination with other feedstocks

Hemp hurd briquettes

- *"A combination of rapeseed meal and hemp shives resulted in increased energy value.*
- *Hemp briquettes are characterized by faster loss of mass during combustion, compared to commonly used briquettes made of wood chips. This results from the fact that heat release from hemp briquettes is considerably faster.*

Loose:
"Energy conversion systems are limited in the range of fuel size acceptable in the feed stock. Fine grained form may not be physically homogeneous and free flowing and may pose difficulties in transportation, metering, storage and feeding. Fibrous and pliable biomass can cause communition problems.

Wheat straw

- *"In comparison to wood residues, agricultural residues such as wheat straw are higher in ash, N, K and Cl content and therefore there are more problems with emissions, deposit formation (slagging and fouling) and corrosion.*

Oat hulls

- *"University of Iowa Biomass Fuel Project showed that oat hulls can be co-fired with coal in its circulating fluidized bed boiler. The feather weight oat hulls required special materials handling solutions, boiler control system modifications, and new procedures to make this fuel work as a viable long-term source of energy for UI.*

Sunflower hulls

- *"ADM Northern Sun plant utilizes sunflower hulls in combination with other feedstocks such as ground railway ties. Their boiler is designed for burning hulls.*
- *University of North Dakota co-fired sunflower hulls with coal.*
- *Some of the problems associated with burning sunflower hulls include:*
    - *High potassium content can cause problems in combustion process*
    - *Feed issues related to high volatility and low weight.*
    - *Vertical and horizontal segregation in the storage bunkers is a concern.*
    - *Problems with sunflower hull dust caused feed in problems (fires).*
    - *Considerable modifications to plants utilizing sunflower hulls.*

Flax shives

- *"Difficult to grind and evenly feed into combustion unit."*[52]

A summary of the processed biomass feedstocks available is provided in Table 4.12.

[52] Prairie Practitioners Group (MAFRI): "Biomass Conversion Feasibility Study Supplier Analysis" March 2009, pp. 30-42.

Table 4.12: Summary of Processed Biomass Feedstocks Available[53]

Biomass Feedstock	Quantity per Year (tonnes)	Energy Value MJ/kg	Total Energy Value (PJ) @90% eff.	Present Use as Fuel in Manitoba
Flax shives	60,000 to 70,000	17.4	1.10	Yes
Pellets		17.7		
Oat Hulls	48,500	19.5		
Pellets		18.7	0.82	Yes
Sunflower hulls	10,000 to 13,500	18.6	0.23	Yes
Pellets		17.3		
Wheat Straw	Depends upon the area of the province	16.2		
Pellets		15.5		
Hemp hurds	Negligible (See Note)			
TOTAL	**118,500 to 132,000**		**2.14**	

Note: Although the supply of hemp hurds available at this time is negligible, it is known that many acres of hemp are grown annually for seed. If the market for the fibre were to become developed then the amount of hemp hurd available would be substantial.

4.4.3 Agricultural Biomass Logistics

The following section was created by the Prairie Practitioners Group in their study for MAFRI (Biomass Conversion Feasibility Study – Supplier Analysis). Please refer to this study for full references and context.

Transportation

"Given the volumes of (the biomass) most if not all transportation needs will need to be met by trucks. Most rail movement today occurs in 100 car unit trains that can carry at least 60 to 80 tonnes per car. While there may be an option to look at rail transportation for the Pine Falls, Brandon/ACC and Parkland regions, preliminary analysis indicates that trucking is the lowest cost option. According to one estimate the cost of rail freight from Portage to Brandon was $13.33 per tonne as compared to $9.52 per tonne by truck.

"According to Manitoba Agriculture in 2008, the cost of trucking ranged between $1.47 per km for a unit valued at $95,000 up to $2.23 per km for a unit valued at $175,000....(Based on scenarios developed by PPG) is an assumption that (most) agriculture crop residues will travel an average of 35 km. That would equate to an estimated transportation cost of between $5.00 and $8.00 per tonne assuming a 20 tonne load. Cost per tonne for moving "bulkier" materials such as flax shives or oat hulls could be higher.

[53] Prairie Practitioners Group (MAFRI): "Biomass Conversion Feasibility Study Supplier Analysis" March 2009, pp. 30-42, Additional information input by DLF Consulting

Storage

"Storage requirements for biomass feedstock vary considerably with the type of feedstock and the type of processing required. In the densification process a consistent feedstock is desired to achieve the desired consistency in the densified product. In some cases the cost of storage must be balanced with the ability of the processing system to accommodate variation in the feedstock.

Types of Storage Systems

Straight Wall Enclosed Building
"In their feasibility study for an agricultural biomass pellet company, Campbell Consulting suggested the following facility for the storage of small particle agricultural processing residues and wood residues. "A bare, uninsulated 20,000-square feet warehouse structure suitable for this purpose is estimated to cost about $280,000. (This warehouse would be a big pole building; the walls would not have the lateral strength of a grain storage building.)" If this building were loaded to a height of 10 feet, it would be providing storage for a volume of 200,000 cubic feet. The cost of this building in Canadian dollars, based on an exchange rate of $1.22 CDN to $1 US, is $341,000 CDN ($1.71 per cubic foot).

Quonset Steel Building
"A 70 foot by 240 foot steel storage building would have floor area of 16,800 square feet. If loaded to an average height of 10 feet, this building would provide volume of 168,000 cubic feet.

Canvas Covered Building
"Buildings can be constructed in various dimensions. Winkler Canvas provided an estimate of the cost of a 50 foot by 100 foot building on 8 foot pony walls. The installed cost, excluding flooring, would be $55,284. Estimates of flooring costs are $6.00 per square foot for concrete and $3.60 per square foot for asphalt paving.

Hopper Bottom Bins
"The following is an example of hopper bottom bin manufactured by Meridian Manufacturing of Winkler. A hopper bottom bin with a capacity of 6406 bushels equates to 8200 cubic feet using a conversion factor of 1 Imperial bushel equalling 1.28 cubic feet. This bin sells for $25,800 CDN ($3.15 per cubic foot).

Types of Feedstock

Flax shives
"Flax shives are normally loaded into trucks directly from the flax straw processing plant. These trucks then deliver the flax shives directly to the end users. As an example of the tonnage of flax shives stored in a particular facility, the Straight Wall Enclosed Building in 4.4.1 has a volume of 5601 m3. Using 108 kg/m3 as the density of flax shives, there would be 605 tonnes of flax shives in the building. To preserve consistency, screened shives for systems, such as the Powerlog system, inside storage may be required.

Oat hulls
"Ground oat hulls can be stored in flat bottom grain bins and removed with floor mounted screw augers.

For the livestock feed market, oat hulls can be stored outside. After water is applied a crust forms on the pile and this crust will prevent further infiltration of water.

Sunflower hulls
'Sunflower hulls can be stored in hopper bottom grain bins and handled with common grain handling equipment.

Wheat straw
"The options for the storage of wheat straw depend upon the potential usage of the straw. When bales of wheat straw are stacked directly on the ground, the bottom layer may deteriorate. Some straw suppliers anticipate directing this bottom layer of bales into a lower value market." [54]

Section 4.1.6 of the Straw Procurement Business Case Study contains descriptions of the storage requirements of businesses which have used, are using or plan to use straw fibre.33 Below is a chart of "Storage Parameters for Different Uses" which is included in that study.

A summary of biomass storage parameters is provided in Table 4.13.

Table 4.13: Biomass Storage Parameters[55]

Storage Parameters for Different Uses		
Usage	**Applicable Crop**	**Storage Needs**
Biomass to Heat and Power • Cubes	Cereal straws, corn stover, flax shives	• Storage may be required to maintain the moisture between 15 and 20% • Moisture content of 17 % is desired
Biomass to Heat and Power • Pellets	Cereal straws, flax shives	• Good quality and consistency is required • Alternatively, the ability to select high quality straw from a large supply with other markets for the lower quality straw
Biomass to Heat and Power • Round bales	Cereal straws, flax bales	• Storage requirements are minimal • Stacking technique helps to avoid moisture uptake (bottom row of bales on end and top row on side)
Industrial Uses of Flax such as in Composites and in Paper	Flax	• Round bales are tarped. No preparation to the base (so that the land can be returned to farm production after the bales are removed) • Retting of flax straw is an important quality consideration and various options are being considered to increase the retting (i.e. spring baling)
Cellulose to Ethanol • Round bales	Wheat, barley, oat and rye straw	• Storage requirements are minimal since additional feed stock prices are to be avoided

"For a comparison of costs of various types of storage we refer to a study done for the Chariton Valley Biomass Project (Draft Fuel Supply Plan) in 2002. This study assessed the storage requirements and compared various storage options for the securing of up to 200,000 tons of biomass annually from 50,000 acres and involving as many as 500 farmers. They looked at a combination of on-site storage and off-site storage of baled

[54] Prairie Practitioners Group (MAFRI): "Biomass Conversion Feasibility Study Supplier Analysis" March 2009, pp. 22-28
[55] Prairie Practitioners Group (MAFRI): "Biomass Conversion Feasibility Study Supplier Analysis" March 2009, p. 26

switchgrass. In this study they discuss the off-site storage methods, associated costs, and Iowa's experience with these methods and storage requirements. The six storage methods studied included outside unprotected (on-ground or on-crushed rock), reusable tarps, pole -framed structures (open-sided or enclosed), and steel sheds.

"After accounting for dry matter loss, the cost of the various types of off-site storage ranged from $8.53 per ton for reusable tarps on crushed rock to $17.10 per ton for a pre-manufactured steel storage shed.

Hemp hurds
"Hemp hurds are quite absorbent and this absorbency has been attractive to the animal bedding market. This absorbency will require enclosed storage to preserve quality.

Storage of Biomass Materials
"Because of the variation in the densities of the different forms of biomass materials the costs of storage of these materials varies as well"[56] (See Table 4.14).

Table 4.14: Storage of Biomass Materials: Raw and Densified[57]

Raw Materials

Type of Biomass Material	Density (kg/m^3)	Storage Facility	Capacity in Tonnes	Capital Cost per Tonne of Capacity per Year
Oat hulls	235	Hopper bin	54	$18.52 (See Note 1.)
Sunflower hulls	194	Hopper bin	44.5	$22.47 (See Note 1.)
Flax shives	108	Straight wall building	605	$19.83 (See Note 2.)
Wheat Straw Bales		Outside – not covered[35]	Outside	$5.00

Densified Materials

Type of Biomass Material	Density (kg/m^3)	Storage Facility	Capacity in Tonnes	Capital Cost per Tonne of Capacity per Year
Oat hull pellets	747	Hopper bin	172	$5.81 (See Note 1.)
Wheat straw pellets	500	Hopper bin	114	$8.77 (See Note 1.)
Wheat straw briquettes	400	Straight wall building	2240	$5.36 (See Note 2.)
Briquettes (75% flax shives & 25% sunflower hulls)	320 – 480[36]	Straight wall building	1792 – 2688	$6.70 - $4.46 (See Note 2.)
Cubes (flax shives, wood, paper)[37]	550	Hopper bin	126	$7.94 (See Note 1.)

[56] Prairie Practitioners Group (MAFRI): "Biomass Conversion Feasibility Study Supplier Analysis" March 2009, p. 26
[57] Prairie Practitioners Group (MAFRI): "Biomass Conversion Feasibility Study Supplier Analysis" March 2009, p. 27

Note 1: This estimate is based on the 6409 bushel hopper bin referenced in 4.4.1. This bin has a capacity of 8200 cubic feet or 229.6 m3. Assume an annual capital cost of approximately $1000 based on an initial cost of $25,800 and a life span of 30 years.

Note 2: This estimate is based on the straight wall enclosed building referenced in 4.4.1. This building has a capacity of 200, 000 cubic feet or 5600.7 m3. Assume an annual capital cost of approximately $12,000 based on an initial cost of $341,000 and a life span of 30 years.

Note 3: For materials stored in grain bins which are subject to bridging (such as oat hulls and sunflower hulls), safety precautions should be observed when removing the materials from the bins.

4.5 Forestry Biomass Feedstock Processing and Logistics

4.5.1 Forestry Biomass Processors

The densification of forestry biomass directly into heat, or into pellets, cubes, briquettes or pucks is done by large customers for their own end use, as shown on Table 4.15 as well as by smaller businesses as described later in this section.

Table 4.15: Current Manitoba Industrial Bioenergy Production[58]

Name of Facility	Type of Facility	Location	Fuels Used	Type of Energy System	Electrical Energy Balance
Tolko Industries Ltd.	Pulp mill	The Pas	Spent Pulping Liquor (68%), Hog fuel (17%), Heavy Fuel Oil (15%)	Co-gen Thermal Capacity: 193,930 kW Electrical Capacity: 22,000 kW	360 MWh produced 240 MWh purchased
Tembec	Newsprint mill	Pine Falls	Bark, biofuel. Coal, sludge	3 power boilers	0 MWh produced 1,300 MWh purchased
Louisiana Pacific	OSB manufacturer	Swan River	Hog fuel	Hog for steam/heat and drying - thermal oil system	Heat Production Only
Loewen Windows	Window manufacturer	Steinback	Sawdust and trim blocks	2 boilers – 1 for shavings – 1 for trim blocks	Heat Production Only
Pine Land Nursery	Greenhouse for tree seedlings	Pine Falls	Kiln dried seed waste, wood chips from adjacent forestry operation	Blue Flame Stoker boiler system – compatible with multiple fuel types	Proposed 100 KW Cogen System for internal electrical use only – MB Hydro Bioenergy Optimization Pilot site
Spruce Forest Products	Sawmill	Swan River	Sawdust and hog fuel	Heat recovery system for kilns and building	Heat Production Only
Defehr Furniture Ltd.	Particle board manufacturer	Winnipeg	Sander dust – 4350 metric tonnes annually at full production	2 wood fired boilers – heat for facility & manufacturing process	Heat Production Only

Other businesses involved in the densification of forestry biomass in Manitoba include:

- **Prairie Bio Energy** – Located in La Broquerie, PBE is currently producing a 7/8" cube made of biomass products. The primary components of the fuel cubes include a mixture of wood by-products and flax shives. The energy content is approximately 7900 BTU per pound. This fuel is equivalent (if not higher than) in

[58] PricewaterhouseCoopers (Manitoba Conservation), "Manitoba Wood Biomass for Heating and Energy Feasibility Study" March 2009, p. 52.

energy to Lignite coal. The fuel cubes have an average density of 33 pounds per cubic foot and a moisture content of 5-6%.[59]

- **Prairie Pellet** – St. Claude (no information)
- **Westroc Energy** – No operations at this time, sells coal, has line to cubing equipment.[60]

4.5.2 Forestry Biomass Logistics

The information in this section (4.5.2) has been prepared by PricewaterhouseCoopers in their study for Manitoba Conservation, March 2009[61].

Harvesting Capacity

The majority of harvesting in Manitoba is done by feller bunchers (90%), with chainsaws (10%) still being used by smaller operators. Tops and limbs are removed at the stump unless special permission has been obtained from MC. The tree lengths are then skidded by grapple skidders to roadside where they are either processed into logs or chipped on site and blown into chip vans. In many areas (eastern, northern and west-central) winter harvesting requires central yards where the softwood tops are hauled for further processing with a chipper at a later date.

Due to mills taking downtime because of poor market conditions, there is an excess of harvesting capacity in the Province at this time.

Table 4.16: Current Logging and Chipping Capacity in Manitoba

	# of Logging Companies	% of Manitoba's Production
Conventional (1 person)	15	10
Mechanical (2-7 employees)	38	50
Mechanical (8-15 employees)	10	25
Mechanical (>15 employees)	2	15
Total	**65**	**100**

Source: Manitoba Conservation

In discussions with MC staff and license holders in the Province, the largest portion of contractors in the Province are in the 2-7 employee range which is likely a single logging side. These contractors supply approximately half of the volume in the Province while most of the rest comes from larger contractors. It has been indicated that there are approximately 18[18] machines in the Province with chipping or grinding capacity with 8 of those being fixed at sawmill locations and the remainder being mobile.

[59] Prairie BioEnergy: http://www.prairiebioenergy.com/product.html
[60] Westroc Energy: http://www.westrocenergy.com/
[61] PricewaterhouseCoopers (Manitoba Conservation), "Manitoba Wood Biomass for Heating and Energy Feasibility Study" March 2009, pp. 28-29

Accessibility

Accessibility differs greatly across the Province. Approximately 70% of the harvest occurs between November and March. The average haul distance across the Province is 150 km.

Accessibility in the Eastern portion of Manitoba is primarily winter only access, with many frozen roads as well as ice bridges. This area is boreal shield as well so road building costs tend to be expensive and gravel is hard to come by.

Accessibility in the Northern portion of the Province varies by Forest Section. The Hayes River and Churchill Forest Sections have limited or no road infrastructure. The harvest to date has concentrated on the areas close to the highway or the railway, which increases the cost and availability of future harvests. The rail line is reported as being in poor shape and undependable, so this will have to be taken into account when considering future development.

Transportation Costs

At the present time there would be sufficient handling capacity to move biomass material by truck in the areas of the Province where the three Forest Management Licencees operate. Roads are in good shape and well distributed and not generally seen as an issue. The review of Manitoba On-road Transport for the forest industry revealed that generally the cost and competitiveness of log transportation in the Province is at or better than the Canadian average, depending on location.

The average haul distance in Manitoba to most mills is 150 km's one way. The rates paid for trucks hauling forest products ranges between $95 and $110/ hour. Most mills also pay a fuel surcharge to keep the fuel price fluctuations from causing issues with the haulers. The costs per m^3 range from $10.80 to $13.43 for these distances. In Manitoba, 70-80% of wood is hauled in the winter[19].

In more remote and undeveloped areas of the Province, transportation costs may be slightly higher than other regions due to a lack of trucks and poorer quality of infrastructure.

4.6 Densification Research and Development

Prairie Agricultural Machinery Institute (PAMI) in Portage la Prairie is an applied research, development, and testing organization serving manufacturers and farmers. One of its projects is a mobile biomass densification unit which will densify straw into 7/8" cubes. Not unlike the old tradition of a mobile harvester which would be moved around to serve many farmers. This unit when completed will be able to be moved around to different sites where farmers can bring their straw and leave with densified cubes (Figure 4.5).

Figure 4.5: PAMI Mobile Biomass Densification Unit

4.7 Biomass Summary

Manitoba produces 12.7 million tonnes of agricultural and 1.7million tonnes of forestry biomass per year (or 1.8 Gt using BIMAT waste wood amounts), for a total of 18.4 Gt – an amount which will vary from year to year depending on many factors. These include: variability in the commodity markets; weather; housing markets; and environmental factors like disease and insects. The majority of the agricultural biomass consists of: wheat; canola; oat; barley; flax; corn; and sunflower residues. The forestry biomass consists of: logging residuals; sawmill residuals (sawdust, woodchips and hogfuel); rural and urban wood waste (both construction/demolition related, and tree/brush trimmings); and cut logs used by residential heating applications.

In order to be sustainable, only one third of the agricultural biomass should be taken from the land any given year to take into account conservation needs, and that of the forestry residue listed above, only 14% would be used. (This percentage, although small, is over four times what is presently estimated as use of this resource.) The biomass total includes Manitoba's agricultural processing residues of approximately 125,000 tonnes (oat hulls, sunflower hulls, flax shives) per year. The total of the two residuals is between 4.1 and 4.2 million tonnes.

Most of this reduced amount is still not available for heating purposes at present. To be used for heat, biomass must be collected and converted into a form usable by the various heat generating technologies available. The primary feedstocks used for heat in Manitoba are by-products from agricultural processors (oat hull pellets, flax shives and sunflower hulls) and the forestry industry (wood chips, hogfuel, cut logs and sawdust). These two biomass sub-categories together amount to approximately 173,000 tonnes (2.6 PJ) per year (agriculture - 125,000 tonnes and forestry - 48,000 tonnes), or 1.2% of the total biomass available in Manitoba - not even all of this, however, is used presently for heat.

Prospects

Both the agriculture and forestry industries are developing fuel crops which have the capacity to significantly increase the amount of biomass which can be used for heating purposes. The short term prospects due to the short growth cycle include the growing of

switchgrass, which while having a similar energy density as that of existing agricultural biomass resources, will produce up to three times (6 tonnes) the quantity of biomass per acre. The longer term prospects due to the extended growth cycles in the forestry industry are fuel crops like willow and hybrid poplar which could provide a per acre yield 5 – 7.4 oven dry tonnes (odt) per hectare per year. The 40,000 square km of land deemed available by the province (PWC Study) would yield an average of 20 million odt per year. At 15 MJ/kg, this amount of biomass could generate 270 PJ (@90% efficiency); more than four times more than the projected agricultural biomass figure.

Although both are biomass resources, there are important differences between forestry and agricultural biomass to be considered (Table 4.17).

Table 4.17: Traits of Forestry vs. Agricultural Biomass

Forestry	Agricultural
Multi-decade crops	Annual crops
Generally distant from towns and cities	Often within 1-2 hours from towns and cities
Accessibility challenges to planting and harvest	Open access to fields
A few large owners	Many smaller owners
Require large centralized processing facilities	Local processing of product and biomass
Multiple subcontractors: planting, harvesting, processing	Few subcontractors
Easier access to large quantities of biomass (lumber byproducts) in a few facilities	Widespread dispersed biomass
Difficult access to tree toppings, branches, other usable biomass	Potential difficulties accessing residues based on weather

Developed in Table 4.18 is a summary of feedstocks in Manitoba providing an overview of the different feedstocks, their present use, the status of the supply chain, forms available (e.g. pellets, pucks) and emerging and its potential role as a biomass feedstock.

Table 4.18: Summary of Feedstocks in Manitoba

Manitoba Feedstock	Present use as an energy feedstock in Manitoba	Present status of energy feedstock supply chain in Manitoba	Forms of feedstock presently available	Emerging forms of feedstock in Manitoba	Potential role as Biomass Heating Feedstock
Forestry Residue					
Sawdust	High	High	Pellets	Cubes, Pucks	High
Hogfuel and Woodchips	High	High	Loose	-	High
Trimmings - Logging	Low	Low	Loose	-	Med
City and town waste - Construction and Demolition	Low	Low	Bulk	Chips	High
City and town waste – tree trimmings and cuttings	Low	Low	Bulk	Chips	High
Agricultural Residue					
Wheat					
Straw	-	-	Bale	Cubes, pucks	High
Oats					
Hulls	High	High	Pellets	-	Low-Med
Straw	-	None	None	-	Med
Flax					
Shives	Low	Low	Loose	-	Low
Straw	-	-	Bale	Cubes	Low
Hemp					
Hurds	R&D	-	-	-	Med
Stalks	-	-	-	-	Med
Corn					
Stover	-	-	Bale	Cubes	Low
Husks	-	-	Loose	-	Low
Sunflower					
Hulls	Low	Low	Loose	-	Low
Stalks	-	-	-	-	Low
Canola					
Straw	-	-	Bale	-	High

Based on the results of this table, the best potential biomass resources to use for the greatest impact are: forestry residues, and canola and wheat straw. The fuels which are, however, available at this time are: hogfuel and woodchips, oat hull pellets, flax shives and sunflower hulls.

An important consideration for the growth of biomass as a heating fuel will involve a close examination of Manitoba's forestry biomass resource. Historic uses with the greatest economic potential for this biomass have been lumber and pulp/paper; however, forestry biomass as a whole represents a large renewable heating resource.

5 Biomass Technologies

5.1 Introduction

"Bioenergy is the conversion of materials derived from sources of either living organisms or their metabolic by-products. Biomass can be converted into solid, liquid or gaseous energy sources, which allows a wide range of applications. It can be:

- *burned directly to produce heat and/or electricity,*
- *converted biochemically to produce liquid fuel;*
- *digested or gasified to produce gaseous fuel; and finally,*
- *pyrolized to produce oils and high value chemicals.*

"Canada has an abundant supply of many types of biomass, which is important in the production of energy, biofuels, materials and chemicals. Bioproducts can be defined as the resulting product from running sources of biomass through a series of bioprocesses that convert them into bio-materials, chemicals or fuels.

"BIOMASS CONVERSION & UTILIZATION TECHNOLOGIES

- *Combustion – convert forestry and agricultural residues and pulp and paper residues into heat and power under environmentally sound conditions;*
- *Gasification – conversion of forestry and agricultural residues and municipal wastes into syngas, a fuel and/or chemical feedstock;*
- *Pyrolysis – conversion of forestry and agricultural residues into bio-oils and value added products;*
- *Fermentation – conversion of starch and cellulose components in biomass to bio-ethanol*
- *Transesterification – conversion of variety of new and used vegetable oils; tall oils; and other agricultural crops and residues into bio-diesel*
- *Anaerobic Digestion – conversion of manures, food processing residues and organic fraction of municipal wastes into methane rich biogas.*[62]

***"Combustion**. The most common conversion of biomass is through combustion. It produces electric power, steam and heat. It is commercially available and regarded as proven technology. However, improvements to further the technology are being developed to help increase efficiencies, reduce emission levels and reduce costs.*

***"Gasification**. Production of a synthesis gas (syngas) in an oxygen-starved environment at high temperatures. The syngas can be used either as fuel gas for production of heat, electricity and process steam or the syngas can be cleaned to remove contaminants and used for production of synthetic natural gas or high value chemicals.*

***"Pyrolysis** is a process that involves rapidly heating biomass at high temperatures in the absence of oxygen which results in producing vapours from the decomposition. Upon cooling, the vapour condenses to form a liquid fuel. This process is known as pyrolysis of biomass. Bio-oils are produced from the pyrolysis of various biomass feedstocks such as hardwoods and softwoods, grasses and agricultural residues for example."*[63]

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[62] Natural Resources Canada: http://canmetenergy-canmetenergie.nrcan-rncan.gc.ca/fichier.php/codectec/En/2008-43/Bioenergy+and+biomass.pdf

[63] NRCAN: http://canmetenergy-canmetenergie.nrcan-rncan.gc.ca/eng/bioenergy/publications/200843.html

The goal of generating heat from biomass can be accomplished in number of different ways with different technologies and feedstocks as illustrated in Figures 5.1 and 5.2.

The bioenergy technologies reviewed in this study are those which convert biomass into heat and covers the following technologies:

- Combustion (Primary and Secondary)
- Gasification
- Pyrolysis, including Torrefaction and Carbonization

Figure 5.1: Agricultural Biomass Flow Chart

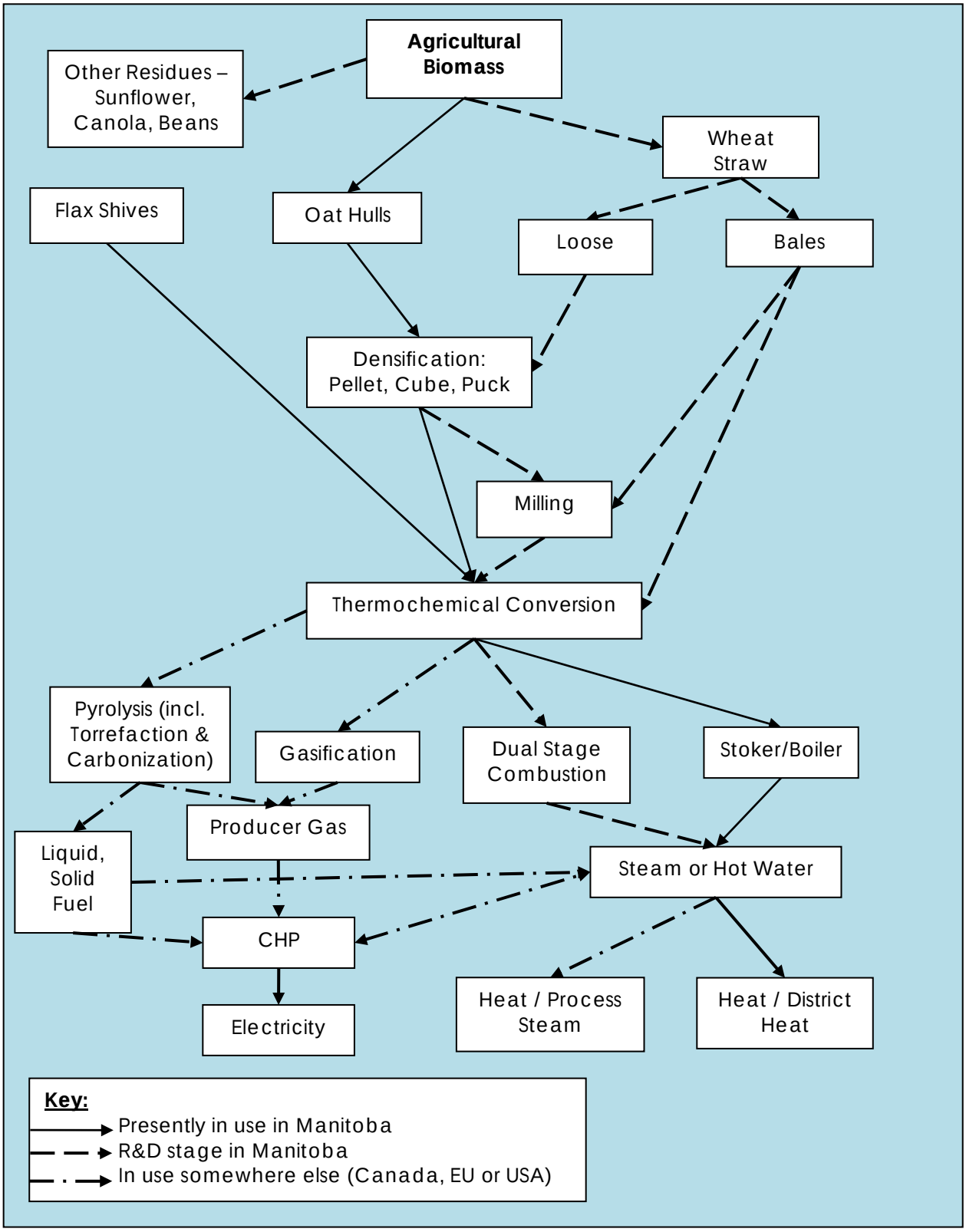
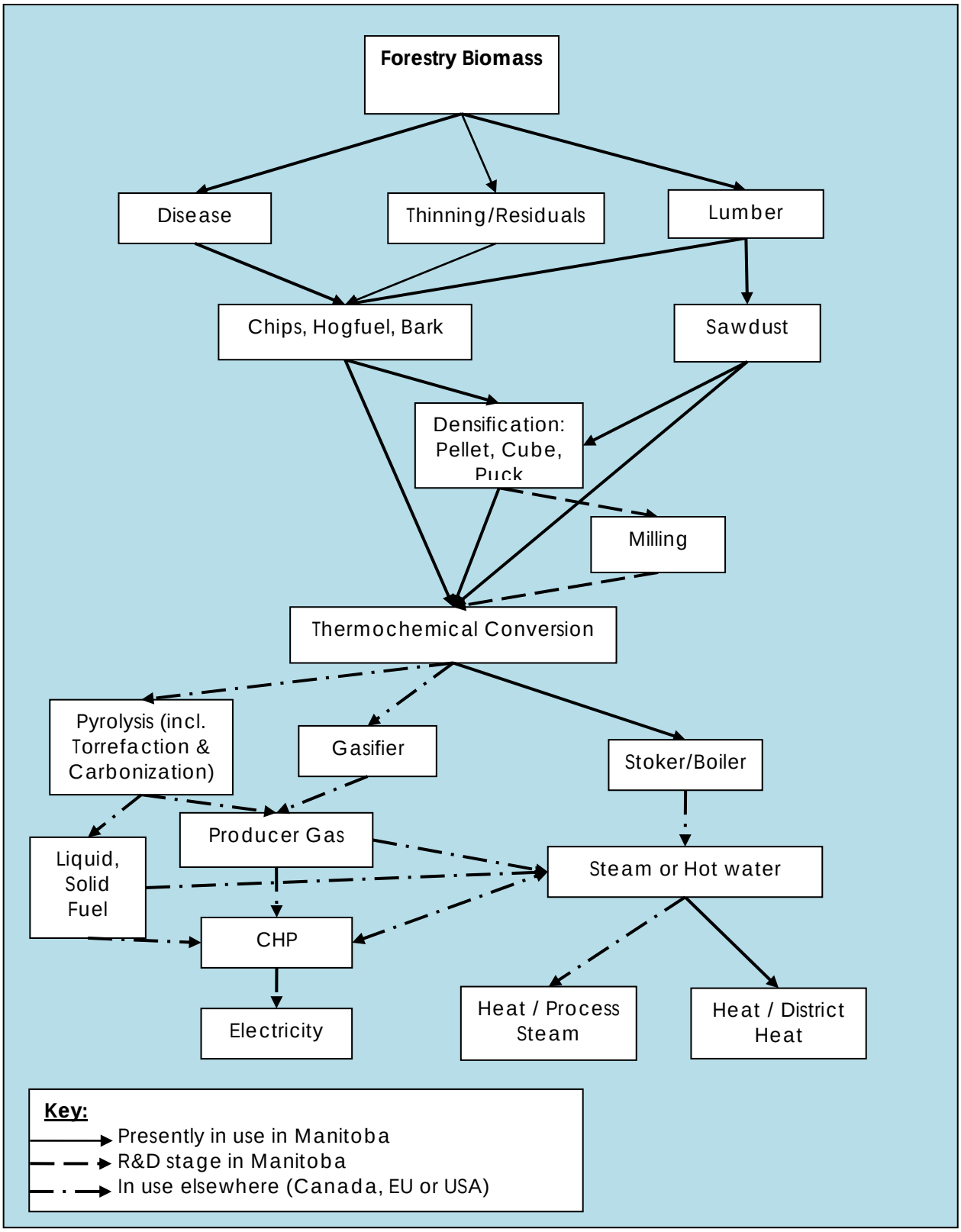


Figure 5.2: Forestry Biomass Flow Chart



5.2 Single Stage Combustion

5.2.1 Residential Biomass Heating

"Many (residents) convert biomass to useful energy in their homes by burning wood in a fireplace or woodstove. Newer forms of residential biomass fuels are pellets and manufactured logs. Charcoal briquettes used in backyard barbecues are another common residential biomass fuel.

"Pellets, briquettes and manufactured logs are different forms of densified fuels. These biomass fuels are made from wood wastes, waste paper and cardboard, and agricultural residues. The first steps in densification are reducing the biomass feedstock to particles ¼ inch or less in diameter and drying the feedstock to a moisture content of 10 to 15 percent. Mechanical compression or extrusion then forms the material into a product that has less than one-third of the feedstock's original volume.

"Heat and compression soften the lignin bonds in the biomass, so that the final product maintains its densified shape. Residual moisture in the feedstock turns to steam during compression and helps lubricate the compression die. Some densification processes use additional binders or lubricants. Different machines produce densified fuel products of different shapes and sizes, ranging from pea-sized pellets to logs 12 inches long and 6 inches in diameter.

"Modern pellet stoves are efficient home heating appliances. A conventional fireplace is less than 10-percent efficient at delivering heat to a home. In contrast, average pellet stove efficiency is better than 55-percent.

"The use of pellet stoves in place of conventional wood stoves reduces the amount of particulate matter in the air. This is especially beneficial in areas where wood smoke from home wood-heating is a major component of local air pollution. In pellet stoves, particulate matter emissions are as much as 90-percent lower than emissions from conventional wood stoves."[64]

A number of wood and pellet stoves are manufactured in Manitoba – two pictured in Figure 5.3 are examples. Some wood furnaces, like the Homesteader Wood Furnace unit, are also able to accommodate whole small straw bales.

[64] State of Oregon: http://www.oregon.gov/ENERGY/RENEW/Biomass/bioenergy.shtml

Figure 5.3: Wood and Pellet Stoves/Furnaces[65]

5.2.2 Commercial Biomass Combustion

Boilers

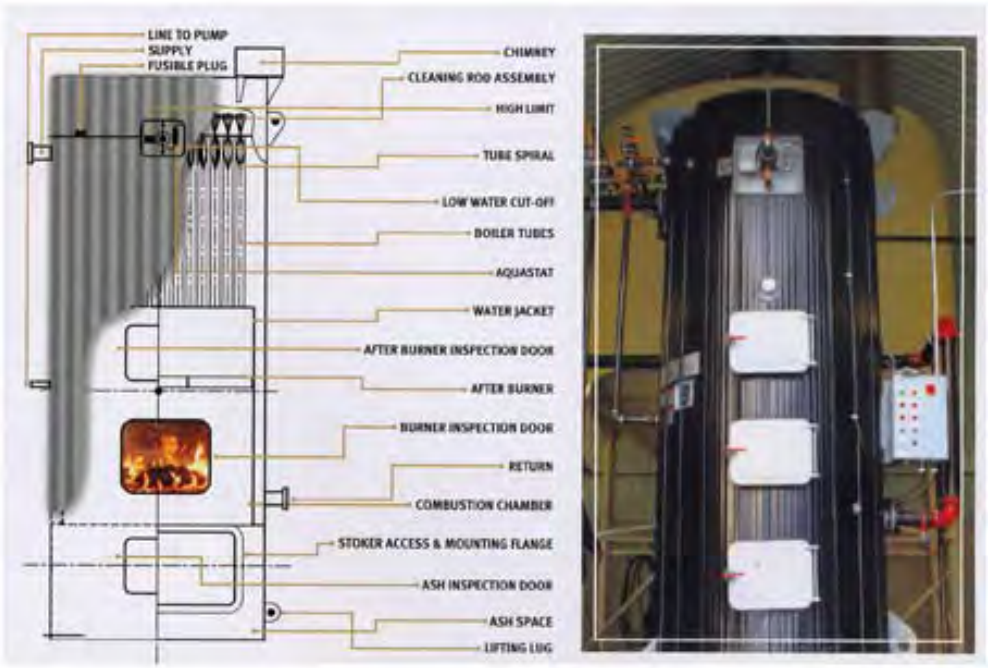
"A biomass-fired boiler is a (an) adaptable direct combustion technology because a boiler transfers the heat of combustion into steam. Steam can be used for electricity, mechanical energy or heat. Biomass boilers supply energy at low cost for many industrial and commercial uses. A boiler´s steam output contains 60 to 85 percent of the potential energy in biomass fuel. The major types of biomass combustion boilers are pile burners, stationary or traveling grate combustors and fluidized-bed combustors. "[66]

The Decker Brand Boiler (Figure 5.4), made in Manitoba is a certified pressure boiler able to burn wood pellets, coal and at one of the Hutterite colonies is being adapted to burn wood chips. "*Decker Manufacturing builds multi-fuel boilers for industrial use, (ranging) in size from 280 000 BTU to 3.5 million BTU… certified by CSA (Canadian Standards Association), ASME (American Standards of Mechanical Engineering), NB, and ABSA. (Decker) specialize in all industrial heating applications—greenhouses, barns, shops, grain dryers, and other heating requirements.*

"…Air filtration systems (are available which) remove particulates and emissions to meet environmental standards. (The Decker models are) up to 85% efficient, (have automated tube cleaning system for maximum efficiency, automated ash removal system and … can be installed in series to meet any BTU requirement."[67]

[65] KOZI Stoves: http://www.kozistoves.com/ HeatInnovations.com (Winkler): http://heatinnovations.com/homesteader.html
[66] State of Oregon: http://www.oregon.gov/ENERGY/RENEW/Biomass/bioenergy.shtml
[67] Decker Manufacturing: http://www.deckerbrand.com/about.htm

Figure 5.4: Decker Boiler[68]



Stokers

"In a stationary or traveling grate combustor, an automatic feeder distributes the fuel onto a grate, where the fuel burns. Combustion air enters from below the grate. In the stationary grate design, ashes fall into a pit for collection. In contrast, a traveling grate system has a moving grate that drops the ash into a hopper. "[69]

The Blue Flame Stoker, made in Manitoba is typically mounted under a boiler made by Boiler Smith (three pass, low pressure boiler rated for 30 Psig water pressure - other pressures available). This system regulates combustion air for efficient solid fuel combustion. The fuel handling system is capable of handling coal and other fuels, such as wood chips and agricultural waste. All the ash augers are driven by hydraulic motors powered by hydraulic systems installed onto the back of the stoker base. The systems include a dust collector designed to eliminate most of the fly ash generated during solid fuel combustion.

[68] Decker Manufacturing: http://www.deckerbrand.com/models.htm
[69] State of Oregon: http://www.oregon.gov/ENERGY/RENEW/Biomass/bioenergy.shtml

Figure 5.5: Boiler Smith Boiler with Blue Flame Stoker[70]

Other combustors

"Fluidized-bed combustors burn biomass fuel in a hot bed of granular material, such as sand. Injection of air into the bed creates turbulence resembling a boiling liquid. The turbulence distributes and suspends the fuel. This design increases heat transfer and allows for operating temperatures below 972° C (1700° F), reducing nitrogen oxide (NOx) emissions. Fluidized-bed combustors can handle high-ash fuels and agricultural biomass residue." [71]

Whole bale combustors

Several whole bale burner manufacturers are located in Europe (one formerly in Manitoba as well, currently not in production), providing systems which shred and burn straw (and other materials) providing heat for hot water, steam or other processes.

"The LIN-KA straw shredder with shredder drums which pull the straw upwards, preventing stones and other foreign objects are passed back into the shredder drums, from where they can be removed. The straw shredder is available in a range of sizes depending on boiler size and is controlled by the load placed on the shredder drums. This means gear and motor overloading is avoided, ensuring that the straw volume set for the boiler plant is always correct. Shredded straw is transported from the shredder in a closed pipe system directly to the combustion chamber, where it passes through a cell sluice before being fed into the combustion hearth by a worm drive.

"…The hot water boiler is a cylindrical, efficient, 3-phase pipe boiler designed for burning straw. It features a smooth flame channel, water-cooled rotation chambers and is

[70] Blue Flame Stoker, Boilersmith Boiler: http://blueflamestoker.com/CGS.html http://www.boilersmith.com/cf3.html
[71] State of Oregon: http://www.oregon.gov/ENERGY/RENEW/Biomass/bioenergy.shtml

dimensioned to achieve full combustion and efficient utilisation of radiated heat in the flame channel, whilst convection heat is utilised to the maximum in the two subsequent flue gas sections.

"…The boiler is available in sizes ranging from 60-1500kW for straw, with the standard version designed for a max. operating pressure of 4 bar, and max. operating temperature of 110º C. An elegant exterior of blue plastic-covered steel panels gives the LIN-KA H boiler an attractive, modern design.

"A stainless steel, laterally-mounted worm drive is fitted in the base of the boiler to transport ash out to the inclined worm drive, which takes it onwards, including outside the building, to an ash container. A number of pressure tanks are mounted on the boiler with air injection valves fitted to inject air into the boiler flue to keep it clean. This means that manual cleaning of the flue is rarely necessary." [72]

Figure 5.6: LINKA Whole Bale Boiler

5.3 Dual Stage Combustion

This section covers two technologies, both made in Manitoba which utilize dual stage combustion technology.

BIOMASS BEST – Manitoba

"The BEST Heating Unit is an updraft, atmospheric pressure gasification system. The baled straw is conveyed automatically to support the gasifier with fuel. The straw disintegration component (straw shredder and shredded fuel conveyor system) then feeds the shredded biomass into the primary combustion chamber (includes the ash removal system, grate system and air distribution system). The hot gases move into the secondary combustion chamber (includes the silicone/potassium removal tray) and into a hot water heat exchanger (includes automatic cleaning system and clean-out removal tray) and then into the exhaust system (the main blower controls air flow and exhausts clean

[72] Linka Energy: http://www.linka.dk/content/us/plant_types/hot_water_plant/straw_60_%E2%80%93_1500kw

vapour). The system has a main computerized control system (combines all necessary electrical devices to control each function with limited supervision)."[73]

Made in St. Adolphe, several of these units are installed and functioning in Estonia and Manitoba.

Figure 5.7: Vidir Best Heating System[74]

RES/OP Technologies

"RES/OP Technologies Inc.'s research, development and demonstration prototype plant north of Fortier Manitoba has been operating since March of 2007. Its organics conversion capacity is 2,500,000 Btu per hour, equivalent to 350 pounds of 15% moisture content wood.

"Orverter™ prototypes have processed samples of MSW, sewage sludge, plastics, fiberglass composites, textiles, leather articles, asphalt shingles, rubber tires, rail ties, wood waste, meat meal, spoiled grains, flax shive, deteriorated straw, manure, bovine-porcine-poultry-mink and fish offal, 150 lb sheep and 300 lb hog carcasses, poultry mortalities, eggs, spent lubricants, autoclaved CFIA lab wastes, and paints.

"The patented Orverter™ technology is a robust, two stage system. Self generated thermal energy dries and transforms all feedstock into organic gasses and ash in the first stage processor. Unburned gasses from the processor are completely destroyed in a secondary, high temperature, flameless combustion chamber."[75]

[73] VidirBest: http://www.vidirbiomass.com/
[74] VidirBest: http://www.vidirbiomass.com/
[75] RES/OP Technologies : http://www.meshtech.ca/resoptechnologies//orverter_technology.html

5.4 Gasification

"Gasification is a thermochemical process that converts biomass into a combustible gas called producer gas. Producer gas contains carbon monoxide, hydrogen, water vapor, carbon dioxide, tar vapor and ash particles. Gasification produces a low-Btu or medium-Btu gas, depending on the process used.

***"Producer gas** contains 70 percent to 80 percent of the energy originally present in the biomass feedstock. The gas can be burned directly for space heat or drying, or it can be burned in a boiler to produce steam. Medium-Btu producer gas can be converted into methanol, a liquid fuel. Electric power generation is possible by combining a gasifier with a gas turbine or fuel cell.*

"Filters and gas-scrubbers remove tars and particulate matter from producer gas. The clean gas is suitable for use in an internal combustion engine, gas turbine or other application requiring a high-quality gas. Use of producer gas in a fuel cell requires reforming clean gas into hydrogen ions and carbon monoxide. Fuel cells produce electricity and thermal energy from hydrogen through an electrochemical conversion process.

"Gasification technology is in the development stage. There are a few demonstration projects that use varied gasifier designs and plant configurations. However, pretreatment of biomass feedstock is generally the first step in gasification. Pretreatment involves drying, pulverizing and screening. Optimal gasification requires dry fuels of uniform size, with a moisture content no higher than 15 percent to 20 percent.

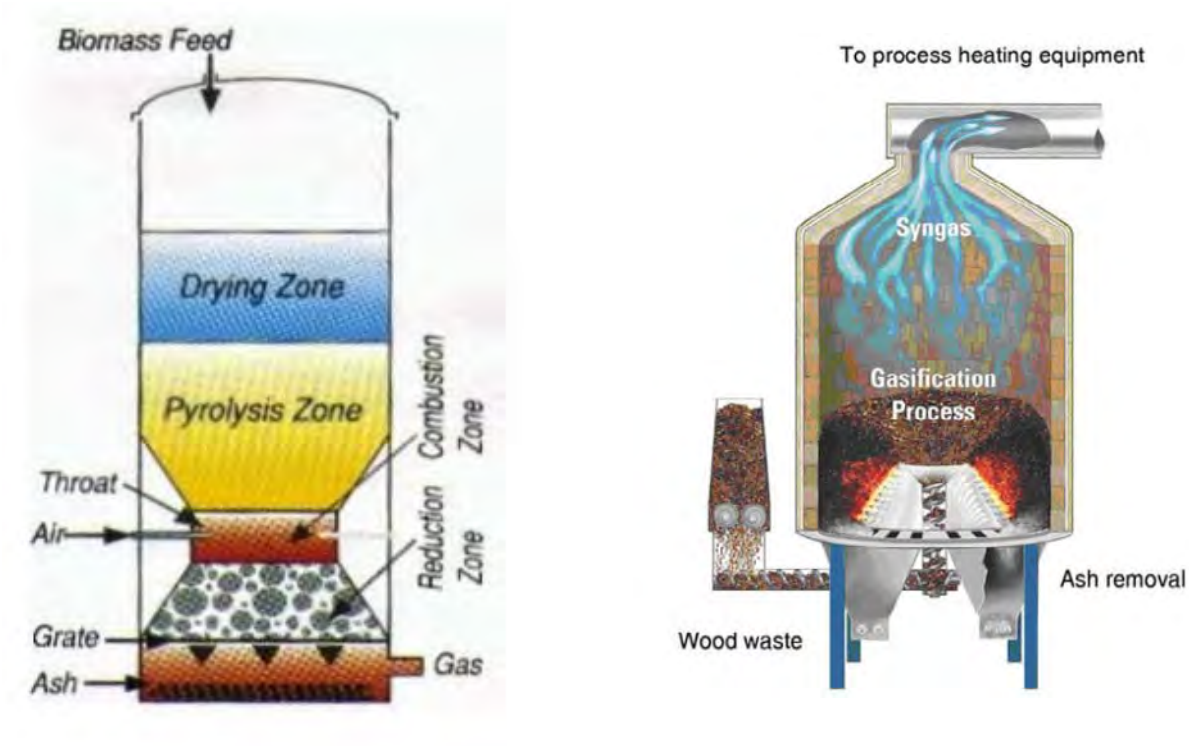
"Biomass gasification is a two-stage process. In the first stage, called pyrolysis, heat vaporizes the volatile components of biomass in the absence of air at temperatures ranging from 450° to 600° C (842° to 1112° F). Pyrolysis vapor consists of carbon monoxide, hydrogen, methane, volatile tars, carbon dioxide and water. The residue, about 10 percent to 25 percent of the original fuel mass, is charcoal. The final stage of gasification is called char conversion. This occurs at temperatures of 700° to 1200° C (1292° to 2192° F). The charcoal residue from the pyrolysis stage reacts with oxygen, producing carbon monoxide.

"In the process of combustion, both stages of gasification occur. When wood burns, the heat of combustion produces pyrolytic vapors. Some gasification of these vapors also occurs. In combustion, however, the pyrolytic vapors are immediately burned at temperatures in the range of 1500° to 2000° C. In contrast, the process of gasification is controlled, allowing the volatile gases to be extracted at a lower temperature before combustion.

Types of Gasifiers
"There are three principal types of gasification systems: updraft, downdraft and fluidized - bed. In an updraft (or "counterflow") gasifier, the biomass fuel enters the top of the reaction chamber while steam and air (or oxygen) enter from below a grate. The fuel flows downward, and upflowing hot gases pyrolyze it. Some of the resulting charcoal residue falls to the grate, where it burns, producing heat and giving off carbon dioxide (CO_2) and water vapor (H_2O). The CO_2 and H_2O react with other charcoal particles, producing carbon monoxide (CO) and hydrogen (H_2) gases. The gases exit from the top of the chamber. Ashes fall through the grate.

"The updraft design is relatively simple and can handle biomass fuels with high ash and moisture content. However, the producer gas contains 10 percent to 20 percent volatile oils (tar), making the gas unsuitable for use in engines or gas turbines.

Figure 5.8: Downdraft (Ankur Scientific) and Updraft (Nexterra) Gasifiers[76]



"Successful operation of a downdraft (or "co-flow") gasifier requires drying the biomass fuel to a moisture content of less than 20 percent. Fuel and air (or oxygen) enter the top of the reaction chamber. Downflowing fuel particles ignite, burning intensely and leaving a charcoal residue. The charcoal (which is about 5 to 15 percent of the original fuel mass) then reacts with the combustion gases, producing CO and H2 gases. These gases flow down and exit from the chamber below a grate. The producer gas leaving the gasifier is at a high temperature (around 700° C). Combustion ash falls through the grate. The advantage of the downdraft design is the very low tar content of the producer gas.

"A fluidized-bed gasifier typically contains a bed of inert granular particles (usually silica or ceramic). Biomass fuel, reduced to particle size, enters at the bottom of the gasification chamber. A high velocity flow of air from below forces the fuel upward through the bed of heated particles. The heated bed is at a temperature sufficient to partially burn and gasify the fuel. The processes of pyrolysis and char conversion occur throughout the bed. Although fluidized-bed gasifiers can handle a wider range of biomass fuels, the fuel particles must be less than 10 centimeters in length and must have no more than 65-percent moisture content. The fluidized-bed design produces a gas with low tar content but a higher level of particulate compared with fixed-bed designs.

[76] Ankur Scientific: http://www.ankurscientific.com/whatisgasification.htm
Nexterra: http://www.nexterra.ca/technology/index.cfm

"If the gasifier is pressurized, it produces gas at a pressure suitable for electric power generation using a gas turbine. High-pressure fuel-feed systems are in the development stage. Hot gas cleanup technology is also under development. Hot gas cleanup removes tars, chars and volatile alkalis to improve system efficiency.

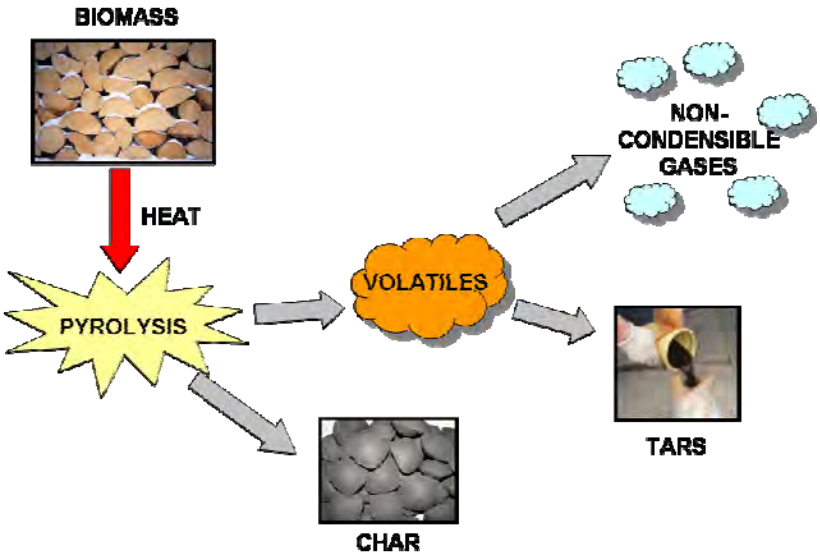
"Progress in the development of biomass-fired gas turbine technology may include combined-cycle electricity generation. In a combined-cycle facility, a gas-fired turbine generator produces primary power. Waste heat from the turbine exhaust is used to produce high-pressure steam, which then drives a steam turbine to generate secondary power."[77]

Aboriginal Cogeneration Corporation
A Manitoba company, the Aboriginal Cogeneration Corporation (ACC) is working to develop a gasifier technology in collaboration with the Energy and Environmental Research Center (EERC) in Grand Forks, North Dakota.

5.5 Pyrolysis

"Pyrolysis is the thermal decomposition of biomass feedstocks at elevated temperatures. During pyrolysis, volatile vapours are released, leaving behind the fixed carbon component of the biomass (char) as a solid product. These upon cooling, the volatiles can be separated into a condensable component (tars) and a non-condensable component (primarily carbon monoxide, carbon dioxide, hydrogen, methane, water vapour, and other gases). Both full combustion and gasification of biomass involve a pyrolysis step.

Figure 5.9: Pyrolysis Conversion of Biomass



[77] State of Oregon: http://www.oregon.gov/ENERGY/RENEW/Biomass/bioenergy.shtml

"By varying the process parameters, the pyrolysis of biomass can be isolated and controlled to favour the production of either char or volatiles. Three basic types of pyrolysis technologies can be used to convert biomass into higher-value energy products. These are:

- *Rapid pyrolysis*
- *Carbonization*
- *Torrefaction*

Rapid Pyrolysis

"Rapid pyrolysis is a process used to convert biomass into a liquid product called pyrolysis oil or bio-oil. In rapid pyrolysis, the biomass temperature is rapidly raised to around 450 to 500ºC in an inert or low-oxygen environment. At this temperature, the biomass flashes to volatiles within a few seconds. The volatile gas is condensed to produce the pyrolysis oil, which has similar physical properties to crude oil. Raw pyrolysis oil is acidic, unstable, and contains significant amounts of oxygen and water vapour, but is still suitable for combustion in industrial-grade boilers. Pyrolysis oil can be refined to produce a product that is more suitable for use in diesel engines and gas turbines; however, this process has not yet been scaled-up for commercial production.

"Ensyn Technologies , based in Renfrew, ON, is a world leader in rapid pyrolysis technology, with a patented commercial process called RTP™, Rapid Thermal Processing. Ensyn has built seven commercial RTP™ plants throughout North America, which produce products for the food, petroleum, and bioenergy sectors. Ensyn has performed a series of studies to determine the viability of establishing an RTP™ plant in Manitoba to produce up to 85 million L/yr of pyrolysis oil from agricultural residues.

Carbonization

"Carbonization and torrefaction are methods of concentrating the energy content of biomass into a high-value solid fuel called biocarbon. Carbonization involves the decomposition of organic polymers (cellulose, hemicellulose, and lignin) within biomass at temperatures above 400ºC. An inert or low-oxygen environment is required to limit combustion. Process parameters are controlled to maximize the production of a solid product with a high fraction of fixed carbon. Higher heating values of carbonized biomass often range between 28 and 32 MJ/kg. The volatiles are often kept hot and combusted to provide heat to for the reaction. Using this heat, the carbonization process is energy self-sustaining for feedstocks with up to 50% moisture.

"The mass yield of solid carbonized product is often very low (approx. 25% to 30%). In addition to a solid fuel, carbonized biomass can be used for filtration and purification (activated carbon) or as a soil amendment (biochar). Carbonized biomass can be sold to either of these markets for a much higher price than as a solid fuel.

"Preseco[78] is an environmental and bioenergy solutions provider based in Finland. Preseco provides a turnkey carbonization facility for the production of biocarbon from biomass. Preseco has established a Canadian subsidiary based in Winnipeg, and has been active in discussion with several interested parties in the province.

Torrefaction

"Torrefaction is a similar process to carbonization, but occurs at lower temperatures (about 200 to 320ºC). At this temperature, the lignin does not decompose, but instead

[78] Preseco: http://www.preseco.eu/index.php?2707

softens to act as a binder for the torrefied product. Mass and energy yields for torrefaction are much higher than carbonization; up to 70% of the dry mass of the original feedstock is retained in the torrefied product, and up to 90% of the energy. Torrefied biomass has an higher heating value of approximately 21 to 25 MJ/kg, and is water-resistant.

"Canadian Bioenergy[79] is a Vancouver-based company focused on project development. To date, their major accomplishments have been several biodiesel refineries; however, they are currently in discussions with a company in the UK to commercialize a microwave torrefaction technology in Canada. Canadian Bioenergy has commenced discussions with Schweitzer-Mauduit and Keystone Grain, both based in Winkler, MB, on the potential for torrefaction of waste flax shives, flax straw, and sunflower hulls."[80]

5.6 Cogeneration

"The use of biomass instead of fossil fuels in combined heat and power applications can provide advantages such as reductions in carbon dioxide (CO2), sulphur and mercury emissions, energy cost savings, waste reduction, and local economic development. Integrated energy systems can use waste heat recovery technology to capture heat byproducts and then generate electricity. By adding biomass fuels into the energy generation process, significant efficiency gains can be achieved. Many sectors, such as pulp and paper and food-processing plants, can produce steam or hot water and electricity from biomass. By using a single-source fuel such as biomass with a cogeneration (CHP) system, the simultaneous production of heat and electricity can be achieved. This can be very advantageous: not only can it supply on-site power, but excess power could also potentially be sold back to the grid."[81]

Processes using biomass feedstocks can cogenerate heat and electricity (sometimes also called trigeneration – heat, cooling and power) using different methods:

1. **Steam**

"Biomass combustion facilities that produce electricity from steam-driven turbine-generators have a conversion efficiency of 17 to 25 percent. Using a boiler to produce both heat and electricity (cogeneration) improves overall system efficiency to as much as 85 percent. That is, cogeneration converts 85 percent of the fuel´s potential energy into useful energy in two forms: electricity and steam heat.

"Two cogeneration arrangements, or cycles, are possible for combining electric power generation with industrial steam production. Steam can be used in an industrial process first and then routed through a turbine to generate electricity. This arrangement is called a bottoming cycle. In the alternate arrangement, steam from the boiler passes first through a turbine to produce electric power. The steam exhaust from the turbine is then "used for industrial processes or for space and water heating. This arrangement is called

[79] Canadian Bioenergy: http://www.canadianbioenergy.com/
[80] Manitoba Hydro: Jeremy Langner Nov 2009
[81] NRCAN: http://canmetenergy-canmetenergie.nrcan-rncan.gc.ca/eng/bioenergy/chp.html

a topping cycle. Of the two cogeneration arrangements, the topping cycle is more common.

2. Direct-Fired Gas Turbine Technology

"The direct-fired gas turbine is another combustion technology for converting biomass to electricity. In this technology, fuel pretreatment reduces biomass to a particle size of less than 2 millimetres and a moisture content of less than 25 percent. Then the fuel is burned with compressed air. Cleanup of the combustion gas reduces particulate matter before the gas expands through the turbine stage. The turbine drives a generator to produce electricity. [82]

3. Producer Gas Combustion

"The biomass gasification process is aimed at producing clean gaseous products at specific chemical compositions that can be converted to higher-value products (such as fuels, chemicals, and power). The gas clean-up requirements depend on its end-use applications. The gaseous product can be directly co-fired in a boiler for heat generation without further clean-up. Power generation in an engine or turbine set requires gas products to be cleaned and conditioned."[83]

5.7 Summary

Each of the technologies reviewed have different characteristics – not only in how the biomass is thermochemically converted into heat (and for some into power) – but also in terms of maturity of the technology itself, market penetration, and experience in the use of different types of biomass feedstocks. An overview is presented in Table 5.1.

Of all the biomass technologies considered in this section, the residential pellet and wood stoves/furnaces appear to have the greatest market penetration and application due to favourable economics (purchase, installation, fuel cost/availability) and simplicity of design understandable by the average consumer. Not only is the technology affordable, but the biomass feedstock system is well developed.

Stoker boilers, although fewer in number, are relatively common in applications such as farm-based industry, Hutterite colonies, district heat, and other commercial/industrial locations with access to biomass resources. Several manufacturers in Manitoba produce these units (Blue Flame, Decker), many units are in operation, and a significant percentage of these are actively experimenting with, and using biomass feedstocks. PAMI also did a study of whole bale burners in 1995, at which time a number of manufacturers were located in Manitoba – only one of which is still occasionally making a large whole bale combustion system.

Gasifiers, as has been noted, are an emerging technology whose primary function is to create producer gas. Given the complexity of the technology and tight fuel parameters, the use of the producer gas simply as a heating fuel is an expensive and complicated way to heat. Using a gasifier as a cogeneration unit provides another energy stream (electricity), but does include significant complications (fuel consistency and

[82] State of Oregon: http://www.oregon.gov/ENERGY/RENEW/Biomass/bioenergy.shtml
[83] NRCAN: http://canmetenergy-canmetenergie.nrcan-rncan.gc.ca/eng/bioenergy/chp.html

automation, gas quality, generator upkeep, grid interconnections) which have limited the spread of this technology. In addition, Manitoba's low electricity prices provide less incentive to use gasification for cogeneration.

Pyrolysis units, like gasifiers do not represent a new technology, but share many of the cost/fuel/consistency requirements. Well proven in Europe, this technology will be featured in one of Manitoba Hydro's demonstration projects in Manitoba.

Table 5.1: Overview of Biomass Thermal Conversion Technologies

Technology	Maturity - Technology	Maturity - Market Penetration	Experience in Use of Biomass as Feedstock	Manitoba Installations	Biomass Options in Manitoba – location dependent	Emerging Biomass Options in Manitoba	5 year Projection	20 year Projection
Residential Wood & Pellet Stove/Furnace	High	High	High	Thousands	Cord wood, wood and oat hull pellets		Moderate Growth	Moderate Growth
Stoker Boilers	High	Med	Low – typically coal	Hundreds	Wood and oat hull pellets, flax shives, wood residues	Wood and straw pellets & cubes	Growth, adaptation	Growth
Gasifiers	Low	Low	Low	None – one in 2010 planned			Initial applications, R&D	Growth
Pyrolysis – Carbonization Torrefication	Low	Low	High	None			Initial applications, R&D	Growth

6 Biomass Heat Applications

A plethora of case studies have been gathered on the topic of biomass heat applications for a variety of applications including:

- Schools
- Community District Energy
- Campuses
- Businesses and Industries
- Community Buildings
- Housing
- Institutions
- Government Facilities
- Agricultural Facilities.

Case studies can be found at the following websites:

- Biomass Energy Resource Center (BERC): http://www.biomasscenter.org/resources/case-studies/
- RETScreen: http://www.retscreen.net/ (biomass heating section)

The following are a combination of sites visited as well as research obtained from the above resources.

6.1 Residential

Due to simplicity of design, function and installation, residential wood and pellet stoves are the most developed sector in the biomass heating world in terms of numbers of units sold. People are comfortable with arranging their own fuel supplies, and for those with larger, rural home/shop locations, wood furnaces are also common. In addition to the adoption of these technologies, the plethora of manufacturers is indication of the relative simplicity of design and construction, permitting many players and a competitive marketplace.

Sample Residential Application
KOZI Stove – Manufactured in Winnipeg[84]
Rating: 40,000 Btu (42,000 Kilojoule (KJ))
Wood Pellets: ~17,000 KJ/kg
Wood pellets: $250 - $300 per ton, $.06 -.10 per kg
50 lb (23 kg) Wood pellet bag will provide a 1200 sf house with low level heat for a day (insulation, condition of house dependent)
~ $2.50 per day heating cost (electricity additional)
Stove: $2,600 - $3,400

[84] Kozi Stoves: http://www.kozistoves.com

6.2 Commercial/Institutional Facilities

Unlike a decision to install a biomass heating system pellet stove as an optional source of heat, installed in a few days and fed with pellets transported, stored and hauled by a motivated homeowner, the process of converting to biomass heat for commercial and institutional locations is complex. These facilities (e.g. hospitals, public facilities, universities, schools) are typically heated by plants located onsite using natural gas, or for more rural or remote applications, propane, coal or electricity. The application of biomass as a heating fuel requires either the replacement of the existing heating system, or integration with an existing hot air, hot water or steam heat distribution mechanism.

The conversion of a heating system to biomass requires understanding feedstock logistics (location, type, transportation, storage, feed mechanisms) and biomass thermal conversion technology (type, controls, emissions). Typically requiring a facility to house the technology, heat distribution equipment and emissions handling devices, additional structures must be built for storage, handling and movement of the feedstock.

Carmen, Manitoba
Facility: Vanderveen Greenhouse
Boilers: 4 Boilersmith with a Blue Flame stoker (total 5.4 MMBtu)
Feedstock: Flax shives

In business for 35 years, Kelvin Vanderveen`s greenhouses produce a variety of plants including 160,000 poinsettias in 2007. Formerly using natural gas, they now use around 10,000 tonnes of shives per year, the four boilers producing 5.5 MMBtu to heat a 800,000 square feet (18 acres). Onsite they have space for seven days worth of biomass storage, obtained locally from the Schweitzer-Maudit flax straw processing operation in Carmen.

Hadashville, Manitoba
Facility: Pineland Forest Nursery
Boiler: 10 MMBtu Boilersmith with a Blue Flame stoker
Gasifier: Planning to install a 75 kW (100 kWth) biomass gasification cogeneration unit in 2010
Feedstock: Forestry biomass (woodchips and hogfuel)

Pineland Forest Nursery has been in operation since 1953 providing seedlings and seed processing services for reforestation. Pineland was originally established to produce bareroot seedlings for the Province of Manitoba and has been producing greenhouse grown containerized seedlings since the early 1970's. Pineland now produces containerized seedlings exclusively in 7.35 acres (3.0 hectares) of greenhouse space. [85]

Two plans for the use of biomass are in process for the nursery: 1) installation of a 10 MMBtu Boilersmith with Blue Flame stoker using wood chips to provide hot water to heat the facility (Figure 6.1); and 2) plans are in place for the installation of a gasifier which will generate heat (100 kWth) and power (75 kW) using an internal combustion engine using the producer gas generated by the gasifier.

[85] Pineland Nursery: http://www.pinelandforestnursery.com/Profile.htm

Figure 6.1: Pineland Biomass Boiler

Pictured are (from top left clockwise): woodchip biomass feedstock, fuel storage facility, stoker/boiler, greenhouse.

Mt. Albion, Prince Edward Island
Facility: Vanco Farms Greenhouse
Boiler: Linka (Danish)
Feedstock: Straw

The Van Nieuwenhuyzen family added tulips to their 800-acre grain and 1,000-acre potato operation in 2002 and began growing fresh cut tulips in a 2,000-square-foot greenhouse. The family has since increased production to almost eight acres. Harvesting begins in January and continues through to Mother's Day. The farm has two refrigerated vans, and the vehicle that delivers to New Brunswick goes on to Boston. Initially shipping once a week, the farm just recently began shipping twice a week to Boston and the other two Maritime provinces. About 15,000 tulips are shipped each week. These are all signs the tulip operation that had a slow start is indeed a blooming success.

During a visit to the Netherlands in 2008, Willem saw a straw burner being demonstrated and was quite impressed. "We were going through a tank of oil every two days, and with the high cost, we had to look at something else." With 10,000 square feet of space and plans to triple in size over the next three years, something had to be done to make heating more affordable. The $300,000 Linka straw burner from Denmark is a one megawatt system that takes up a whole room in the warehouse, carries 4'x8'x3'-foot

bales of straw on a track to a shredder. Here it is separated and sucked into a vacuum pipe that moves the finer straw into the boiler.

It easily heats the 10,000-square-foot greenhouse to 18ºC. It takes about 100 to 300 acres of straw per year to fuel the burner. "It could pay for itself in four years, depending on how the price of oil fluctuates," said Willem. He "guestimates" that the straw costs will be about $20,000 to $30,000 a year. Based on using 100,000 litres of oil a year at 70 cents a litre or more (at the time of my visit earlier this year), the savings would be considerable.

The first of its kind in North America, the straw burner (see Figure 5.6) operates much like a home heating furnace. Hot water is pumped into the in-floor heating systems in the warehouse, Willem's own home, as well as the greenhouse.[86]

Bismarck, North Dakota
Facility: Municipal Hazardous Waste Collection Facility
Boiler: 1 MMBtu, King Coal, Bismarck, ND
Feedstock: Wood Chips

The City of Bismarck has installed a biomass heating system in the facility now under construction at the city landfill. *"This will allow us to realize a beneficial reuse of the wood chips produced from our wood waste supply. We currently average about 4,000 tons of wood waste received per year at the landfill",* said Keith Hunke, Public Works Service Operations Director*. "The biomass heating system being installed in the Household Hazardous Waste Collection facility will use 300 tons per year to heat an 18,000 square foot building".*

The Energy & Environmental Research Center (EERC) at the University of North Dakota in Grand Forks provided technical support to the North Dakota Forest Service (NDFS) and the USDA Forest Service for a feasibility study ***funded under the Fuels for Schools program which promotes utilization of biomass energy in public institutions.***

"This program encourages the use of wood biomass as a renewable, natural resource to provide a clean, readily available energy source and helps public schools retrofit their fuel or gas heating systems to biomass heating systems", said Jackson Bird, Community Forestry Coordinator*. "The program also facilitates the removal of hazardous fuels from our forests by assisting in the development of viable commercial uses of the removed materials,"* he said.[87]

According to Jeff Heintz, Director of Operations for Bismarck's Public Works, and Michael Robb of King Coal, this is the first biomass heated facility in Bismarck. This city of 60,000 with a total of 90,000 in the vicinity, produces 4,000 tons of wood waste per year from parks, pruning, and contractors (not including construction and demolition) which is ground up and fed into a 1 MMBtu system at a rate of 300 tons per year. The heat is transferred to water which is pumped through radiators/fans units located throughout the facility. Another larger biomass heating project is underway to heat a new aquatic facility with a 10 MMBtu unit, to be fired also with wood chips from the city's tree residues.

[86] Greenhouse Canada: http://www.greenhousecanada.com/content/view/1861/63/
[87] City of Bismarck, ND: http://www.bismarck.org/city_departments/department/news_detail.asp?dID=4&ID=579

Bismarck also composts grass and leaves in 30 or so windrows near the landfill and wood residue deposit site. Related biomass work involves 2 digesters (650,000 gallons each) producing methane gas which heats the sludge, the remainder of which is flared.[88]

Figure 6.2: Bismarck Solid Waste Maintenance Building

Fuels for Schools and Beyond:
"The Fuels for Schools and Beyond program is a partnership between the USDA Forest Service's State & Private Forestry Division, the State Foresters of Montana, North Dakota, Idaho, Nevada, Utah and Wyoming, and the Bitter Root Resource Conservation and Development (RC&D) Area, Inc., to promote and facilitate the use of forest biomass waste for heating, cooling and power in public and private buildings.

"The Fuels for Schools Initiative came out of directives from the National Fire Plan of 2001 which included specific grant dollars under Economic Action Programs (under USDA Forest Service State and Private Forestry) for pilot projects to demonstrate new uses of small diameter and underutilized woody material, as well as projects using proven technologies to use such material. The intent of this focused funding was to develop new markets for woody material that has historically been considered waste, so that the substantial cost of thinning hazardous fuels, which generates little in the way of what is traditionally considered "commercial" timber, could be partially offset by the economic value of "non-commercial" biomass."[89]

More information on other related projects can be found in Table 6.1 below.

[88] Jeff Heintz, Michael Robb Interviews July 13, 2009
[89] Fuels for Schools and Beyond: http://www.fuelsforschools.info/aboutFFS.html

Table 6.1: Fuels for Schools Program 2008 Report[90]

Facility	Location	Square Footage	Project Cost	Peak Output MMBTU/hr	Annual Wood Consumption (Tons)	Fuel Replaced	Estimated Annual Fuel/ops Savings	Date Operational
Darby Public Schools	Darby, MT	82,000	$650,000	3	750	Fuel oil	$90,000	November-03
Victor Public Schools	Victor, MT	47,000	$590,000	4.9	500	Natural gas	$27,000	September-04
Thompson Falls Public Schools	Thompson Falls, MT	60,500	$455,000	1.6	400	Fuel oil	$60,000	October-05
Philipsburg Public Schools	Philipsburg, MT	99,000	$697,000	5.1	400	Natural gas	$52,000	January-05
White Pine Co. Public Schools	Ely, NV	36,400	$900,000	3	300	Fuel oil	$35,000	February-05
Council Public Schools	Council, ID	60,000	$1,400,000	1.8	300	Fuel oil and electricity	$59,000	September-05
Glacier High School	Kalispell, MT	220,000	$525,000	6	1900	New construction (natural gas)	$100,000	April-07
U of Montana-Western Campus	Dillon, MT	471,370	$1,423,000	12	3800	Natural gas	$118,000	February-07
Townsend Elementary & High Schools	Townsend, MT	120,000	$425,000	0.68	170	Fuel oil and propane	$19,000	March-07
Northern NV Correctional Center	Carson City, NV	408,000	$8,200,000	30	12,000	Natural gas and electricity	$1,000,000	June-07
Troy Public Schools	Troy, MT	33,235	$299,000	1	60	Fuel oil	$12,500	November-07
Bismarck Landfill	Bismarck, ND	18,000	$200,000	1	220	Natural gas	$13,000	November-07
Kellogg Public Schools	Kellogg, ID	80,000	$1,200,000	4	600	Natural gas	$60,000	August-07
Eureka Public Schools	Eureka, MT	178,000	$1,320,000	5	960	Fuel oil and propane	$103,000	November-07
Browning High School	Browning, MT	130,000	$841,000	4	1250	New construction (natural gas)	$43,000	March-09
Deer Lodge Elementary	Deer Lodge, MT	38,000	$700,000	1.5	730	Natural gas	$35,500	October-08
		2,081,505	$19,825,000	84.43	24,340 tons		$1,831,000	

[90] Fuels for Schools and Beyond: http://www.fuelsforschools.info/pdf/project_status_table.pdf

Townsend, Montana
Facility: Rural School Buildings
Boiler: 0.68 MMBtu
Feedstock: Wood Pellets
Schools in Montana (supported under the "Fuels for Schools" program).[91]

Pellets: A Rural School District's Compact Solution

Townsend, Montana School District, United States

School Wood Pellet Heating System
Heating Capacity (output): 199 kW (0.68 MMBtu/hr)
Annual Wood Pellet Use: 200-300 tons
Year Installed: 2007
Thermal Output: Hot water

Townsend School District (pdf)

When a very small school district serving a low-income community was looking for ways to save on costs, its superintendent looked into wood pellets. The numbers made sense.

"Our existing fuel-oil system, from the early 1990s, was working fine," says Brian Patrick, the superintendent, whose Townsend, Montana district serves about 730 students grades K-12 in two school buildings. But when Patrick attended a December 2003 US Forest Service (USFS) workshop on heating system options he thought wood pellets seemed worth investigating.

Back then, he notes, no one was predicting that fuel oil prices would rise as steeply as they have.

In 2004, the Montana Fuels For Schools and Beyond program, a USFS initiative, paid for an engineer's pre-feasibility study on Townsend's existing system. Townsend next sought and received a Fuels For Schools grant to install a pellet system to heat its elementary school.

After installing its system in 2007, Townsend, one of Montana's first schools to use wood pellets, also became the first Fuels For Schools project to sell carbon offsets. The district has received $12,420 from The Climate Trust for selling more than 130 metric tons per year of carbon-dioxide emission offsets.

"We make an annual report to them, on total energy costs involved in delivering the pellets here and burning them, along with use and consumption here," Patrick says.

Those welcome funds complement a package of financing that Townsend put together to meet the pellet system's $432,000 design, engineering, and construction costs. Along with more than $46,000 of its own funds, the school district brought in the $190,080 Fuels For Schools construction grant, a $15,000 grant from the local conservation district, and a $14,000 grant plus a $140,000 low-interest loan from the USDA Rural Development Community Facilities Grant and Loan Program.

Summary
The heating of buildings using biomass as a heat source is commonly done in North America, with a vast majority using forestry biomass. Of significant note are the two greenhouse operations using agricultural biomass (Vanderveen in Manitoba, and Vanco in PEI) being burned in boiler operations heating large facilities with huge heat requirements. These examples together provide sufficient proof that biomass can be used to provide a reliable heat supply, and can use a variety of feedstocks using mature boiler technology.

[91] Fuels for Schools and Beyond: http://www.fuelsforschools.info/pdf/Townsend_MT_Case%20Study_Wood%20Pellets.pdf

6.3 Community and District Heating

"District Energy is the distribution of thermal energy using a pipeline distribution system. The central thermal plants may use various types of fuel including natural gas, oil or renewable energy. Heat may be generated from either purchased fuel or waste heat. The economic viability of district energy systems relates closely to the energy density of the thermal customers being served. Consequently, district energy systems tend to be located in urban cores serving commercial, institutional and residential customers."[92]

District energy is typically heating, but can include cooling and electricity as well – is not a new topic, with examples across the world going as far back as the Roman baths. The following section takes a look at examples in Manitoba, Canada and a brief look at a few international systems. One of these is the district heating system in Thorsager in Denmark, and the full details obtained for this study can be found in Appendix B.

Hutterite Colonies, Manitoba
Livestock and commercial building heat
Boilers: 3.5 – 7 MMBtu
Feedstock: Coal, woodchips, oat pellets, sunflower hulls

The 104 Hutterite agricultural communities are located primarily in southern Manitoba consisting of 100-150 people living in a communal manner with shared dining, worship and community space. Each colony, in addition to vegetable gardening and farming has a combination of poultry, pig or cattle operations, with some branching into the areas of manufacturing. The heating for the non-residential or community buildings is largely provided using a district heating system (a network of buried hot water pipes) historically fired by coal imported from the US or Saskatchewan ranging from 3 to 7 MMBtu.

Several colonies are experimenting with other fuels including sunflower hulls, oat pellets and wood chips and at least one (Clearwater) has been completely off of coal for three years. The cost of these residues ranges from $40 to $70 per ton depending on the market. The residences and community buildings are heated using propane or geothermal heat. Electricity is provided by Manitoba Hydro at a cost comparable to other large customers due to the fact that the substation at the Colony is owned and maintained by the Colony.

[92] Canadian District Energy Association: http://www.cdea.ca/

Figure 6.3: Hutterite Colony Heating System

Pictured (L to R): Hopper and boiler, large commercial building (100,000 sf) to be heated with biomass.

Table 6.2: Selected Hutterite Colony Heating Systems

Colony	Boiler Type	Boiler Size	Fuel – present / Cost	Fuel – new or experimenting with	Facility
Sturgeon	Boiler Smith Boiler with Blue Flame Stoker	7 MMBtu	Coal		Hog and Dairy barns
Starlite	Boiler Smith Boiler with Blue Flame Stoker	7 MMBtu	Coal	Sunflower Hulls	Hog and Turkey barns
Clearwater	Decker	3: 3.5 MMBtu units	2: Oat pellets	1: Wood Chips	Hog and Turkey barns, Existing and new shop (60,000 ft2)
Rock Lake	Decker	3.5 MMBtu	Co-firing: Coal and Oats		Hog barnsft2

Oujé-Bougoumou, Quebec
Community District Heat
Boiler: 1.2 MW
Feedstock: Woodchips

In 1992 the Oujé-Bougoumou community installed a 1,200 kW biomass boiler from KMW Energy of Ontario and a 1,500 kW oil-fired standby and peaking boiler. The biomass boiler was also fitted with a back-up oil-fired burner. The distribution system consisted of 600 metres of steel pipe and approximately 2,300 metres of plastic pipe. Pipe sizes varied from 108 mm down to 32 mm. The first year's construction included 40 residential units and 5 public buildings.

The energy system, district heating pipes and energy transfer stations that were installed in 1992 cost approximately $1.3 million. The boiler plant and main distribution lines were designed to accommodate the growth of the community expected during the first 5 years.

The village expanded and by the year 2000 the system was connected to 89 detached homes, 11 duplexes, 11 four-plexes and 17 public buildings. By that time, the system consisted of two wood-fired boilers and two oil-fired boilers for back-up and peaking. Sawdust is purchased for $6/tonne and residents pay $192, on average, every two months for their heat and hot water.[93]

In addition to renewable heat, the system provided an opportunity for community decision-making which in turn led to social, environmental and economic benefits. *"A district heating system for Oujé-Bougoumou was conceived of not by engineers or energy technicians nor for that matter by people who had a vast background in the area of energy production or alternative energy, but rather it was conceived of by the people whose professional activity was community development. From the point of view of what is beneficial to an aboriginal community, such a system was found to be an enormously positive tool in contributing to the development of the community's future financial base."*[94]

Charlottetown, Prince Edward Island
Community District Energy
Combined Heat and Power: 35 MW heat, 1.2 MW Electricity
Feedstock: Wood, oil, municipal waste

Canada's largest wood-fired district heating system has been in operation in Charlottetown, the provincial capital of Prince Edward Island (PEI), since 1986. In 1998, the City converted its Civic Centre from stand-alone oil-fired boilers to the biomass-fired district heating system. The Civic Centre is a 8,000 m² facility comprising an arena and exhibition facilities. The old oil-fired boilers were in need of repair and this expenditure was avoided by the connection to district heating.

The PEI Energy Corporation, the company that operates the district heating system, charged no up-front costs for the engineering and installation of the hookup. Instead, PEI Energy is recovering its initial investment via the fixed rate portion of the monthly energy

[93] NRCAN Case Study: Oujé-Bougoumou - http://canmetenergy-canmetenergie.nrcan-rncan.gc.ca/eng/publications.html?2009-10-16-ouje-bougoumou
[94] Oujé-Bougoumou Community: http://www.ouje.ca/content/our-story/energy.php#district

bill that is charged to the Civic Centre. No extra capacity was required at the central plant. All maintenance and service of the district heating equipment is the responsibility of the PEI Energy Corporation.

Using hot water as the heat transfer medium, the district heating system supplies heat to numerous large buildings in Charlottetown, including provincial government offices, the Queen Elizabeth Hospital, the University of Prince Edward Island, the Atlantic Veterinary College, two shopping malls and other commercial and apartment buildings. The system has been extended several times and now comprises a total distribution network of about 16 km. Major investments were made to the system in 1997 to increase capacity and replace emission control systems.

The central plant for the system is currently a Combined Heat and Power (CHP) plant that includes wood- and oil-fired boilers as well as an energy-from-waste facility. The total plant capacity is 35 MW of heat and 1.2 MW of electricity. The system generates about 85% of its energy output from wood and municipal waste with the remainder being produced by oil.

At the Charlottetown Civic Centre, the district heating system replaced three oil-fired boilers for heating and one for domestic hot water. Hot water is also used for the ice resurfacer ("Zamboni") for the hockey arena. About 22% of the heat delivered to the Civic Centre is resold to the adjacent Harness Race Track.[95]

Revelstoke, British Columbia
Community District Heat
Boiler: 1.5 MW
Feedstock: Sawdust

"The Revelstoke Community Energy Corporation (RCEC) burns wood waste generated by Downie Street Sawmills Ltd. to produce steam for the operations of the sawmill and hot water for major municipal, institutional, and commercial buildings including a secondary school, community centre, aquatic centre, motels, stores, and a church. The system consists of a 1.5 MW wood fired biomass boiler and a 1.75 MW backup propane boiler. The City of Revelstoke owns the system and RCEC is a wholly owned subsidiary. To avoid full time supervision at the plant, the boiler uses oil as the non-expansible fluid. A heat exchanger transfers energy to water in the distribution line.

"Costs and Financing

- *Total cost of project: $5.6 million.*
- *Simple ten-year payback.*
- *6.7 percent return on investment.*
- *14.8 percent return on equity.*

"To offset the lack of private-sector financing, the City established the RCEC, to build the wood residue-fired plant Support for the project was provided through a mix of government loans, including the Green Municipal Fund, equity holdings, a credit union loan, and reserve shares to cover capital project costs. In 2005, the project was launched with a 20-year agreement with Downie to purchase RCEC's steam for its dry kilns, provide

[95] NRCAN Case Study: Charlottetown - http://canmetenergy-canmetenergie.nrcan-rncan.gc.ca/eng/publications.html?2009-09-14-Charlottetown

land for the plant, maintain and operate the plant, and supply the primary source of fuel for the plant at no cost."[96]

The district heating system consumes 7,000 tons of sawdust from the sawmill per year, which amounts to approximately 10% of the total sawdust produced when running at full capacity. Half of the heat generated is used to provide steam for sawmill operations, and the remainder is used to heat a growing number of buildings in the district heating loop which consists of nine buildings and more to be added. A majority of the energy for the system is provided by wood residues (85%) and the remainder is done with propane. Original plans were for the system to use hogfuel but difficulties with fuel consistency (cedar wood) led the plant to use sawdust. The plant is fully automated, with two part time staff, and is supported by a dedicated Board of Directors, who maintain community relations, work actively at expansion opportunities and advocate for RCEC.[97]

Figure 6.4 Revelstoke BC District Energy System

Pictured (L to R) : Sawdust storage shed, baghouse, sample heat exchange unit

[96] NRCAN Case Study: Revelstoke - http://canmetenergy-canmetenergie.nrcan-rncan.gc.ca/eng/publications.html?q=revelstoke&x=0&y=0&ty=2
[97] Onsite interview with Geoff Battersby, Revelstoke BC. Nov 4, 2009

Dockside Green, Victoria, British Columbia
Community District Heat
Gasifier: 7 MMBtu
Feedstock: Wood residues

Dockside Green site is a mixed-use residential and commercial real estate brownfield redevelopment located on 15 acres in Victoria close to downtown, adjacent to the Upper Harbour between the Johnson and Bay Street bridges. The City of Victoria saw the redevelopment as an opportunity to create new jobs and new revenue to help fund services, social programs and community amenities such as public art and green space. The City selected Windmill Developments (along with VanCity Enterprises) through a competitive bid process based on a Triple Bottom Line approach, to lead the development of the site.

The developers endorsed this approach balancing economic development and profits with environmental and social benefits in developing the Dockside lands. Construction costs are estimated to be about 1 to 1.5% higher than a normal mixed-use development. VanCity Credit Union is providing $20 million in equity to the project and has first right of refusal for financing all buildings and utility systems and has posted a $25 million guarantee for the project to the City for the various commitments being provided in the development.

All buildings that have been/are being built to LEED™ Platinum standards, except those that are not eligible. Following considerable community input into the planning process, the first residential phase was completed in 2008, the second in 2009, two commercial buildings have also been completed with all buildings on the site expected to be constructed by 2014. A total of 266 suites have been built so far, with a total of 1240 units expected in addition to a small commercial site and offices. Site features include:

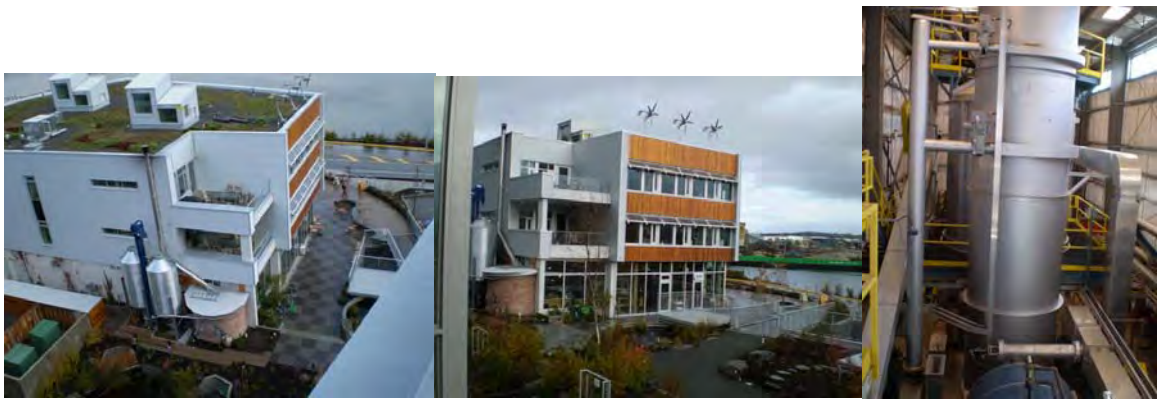
- Biomass Gasification: The site includes a 7 MMBtu (in addition to a 14.3 MMBtu back-up Natural Gas boiler) biomass gasification plant that supplies heat and hot water to buildings within the development making Dockside Green the first large community-scale development in North America to be “greenhouse gas neutral” or better from a building energy perspective. The waste wood gasification process produces a gas that is then burned to produce renewable hot water for use in the development. This smokeless, odourless and efficient process requires 3,000 tonnes of bone dry clean waste wood per year, equivalent to 110 truck (B-train) loads of wood. Plans are for the excess heat produced to be sold off-site to neighbouring businesses which will offset emissions created onsite from electricity and the delivery of waste wood to the site.
- Energy Efficient Building design: The building design approach uses features such as insulation, low E glazing, ventilation air heat exchange, automated shading and daylighting resulting in a at least 50% reduction in design energy cost relative to MNEBC.? Materials used in the facility were selected with consideration of the triple bottom line impact.
- Each residential unit is being equipped with meters to provide information about cold water, hot water, heat and electricity consumption.
- Renewable Electricity: A small amount of electricity is generated onsite through the use of Photovoltaic solar panels and small wind turbines. A solar compactor using photovoltaic technology has also been installed onsite.
- Transportation: Minimal parking requirements permit one parking space per unit and a car share program is in place.

- Mixed Housing: Dockside Green provides a mix of unit size and cost as well as a number of affordable units for sale (26) thus attracting people from a diverse mix of ages and income. In addition Dockside Green will be building 45 affordable units for rent.
- Green Roofs: Most buildings have a green roof with some of them providing space for tenants to do a small amount of gardening as well as space for carefully selected local plants requiring minimal maintenance.
- Sewage Treatment: All sewage discharge (as well as collected rain water) is treated onsite and recycled through separate waterline feeds to the toilets. Reclaimed water also allows maintaining an attractive, naturalised stream in front of the residential portion of the facility that serves not only as a landscape feature but also as a key element of the stormwater system.
- Businesses: Dockside Green has attracted a number of businesses including a coffee shop and bakery which stores its grain onsite and grinding what is required for its daily baking needs.

For the City of Victoria, Dockside Green has created a new expectation for future developments with respect to offering more amenity space and more environmentally appropriate technologies. The development community seems to be responding reasonably well to the higher standards being set. Dockside Green has just received LEED Platinum rating under LEED for Neighbourhood Development – a voluntary, consensus-based certification program for developing sustainable buildings and communities.

Dockside Green is living up to its commitment to be a worldwide showcase of sustainable community design using the Triple Bottom Line approach and demonstrates that ecological regeneration and social principles can be embraced while enjoying economic success.[98]

Figure 6.5: Dockside Green Gasifier



Pictured (L to R): Dockside Green green roof, commercial building, Gasifier

[98] Information collected from the following sources: 1) Onsite interview with Martine Debois, Dockside Green's Director of Sustainability; 2) http://docksidegreen.com/community/overview/overview.html; and 3) NRCAN Case Study: Dockside Green - http://canmetenergy-canmetenergie.nrcan-rncan.gc.ca/eng/publications.html?q=dockside+green&x=0&y=0&ty=2

St. Paul, Minnesota
Community District Energy
Combined Heat and Power: 65 MW Heat, 25 MW Electricity
Feedstock: Urban wood waste

"Launched as a demonstration project in 1983, District Energy was Saint Paul's response to the energy crises of the mid- and late-1970s. The venture was a public/private partnership among the City of Saint Paul, State of Minnesota, U.S. Department of Energy and the downtown business community, all of whom wanted to prove the viability of a hot water district heating system in a state with cold winters.

"In 1993, ten years after the successful startup of the district heating system, District Energy began offering district cooling service to downtown building owners. And ten years later, in 2003, District Energy became a "green" energy service provider following construction of an affiliated combined heat and power (CHP) plant that is fueled by a renewable resource—clean, urban wood waste. Using renewable energy, the CHP plant simultaneously produces about 65 megawatts of thermal energy for District Energy and 25 megawatts of electricity for Xcel Energy. It is the largest wood-fired CHP plant serving a district energy system in the nation.

"District Energy currently heats more than 185 buildings and 300 single-family homes (31.1 million square feet) and cools more than 95 buildings (18.8 million square feet) in downtown Saint Paul and adjacent areas. Its cooling system includes two chilled water storage tanks that hold 6.5 million gallons of water chilled at night, during off-peak electrical hours, for consumer use during the day. Customers enjoy stable rates, unsurpassed reliability and energy efficient heating and cooling service."[99]

Thorsager, Denmark
Community District Heat
Boiler: 3.15 MW
Feedstock: Straw

The heating plant in Thorsager, Denmark is a typical straw fired boiler system for this size range. Heat is supplied into a district heating network, with 384 connected heat consumers that cover most of the town. The boiler plant receives straw from nearby farmers as 500 kg Hesston bales, which are shredded before combustion on a moving grate. The straw boiler has a nominal heat production capacity of 3.15 MW thermal output. As spare capacity and for peak load heat demand during the coldest periods of winter, an additional oil fired boiler of exactly the same capacity, nominal 3.15 MW thermal output is installed.

A thermal heat storage consisting of a cylindrical water tank can even out load variations on the heat demand side. This way the boiler can be operated under more optimal combustion conditions, and straw fired heat can cover the demand, even when the demand - for shorter periods - exceeds the boiler capacity. The straw boiler is typical for Danish district heating plants, where the average is about 4 MW thermal output, and where virtually all plant are between 1 and 10 MW. The main fuel for the district heating plant is agricultural residues in the form of straw (mostly wheat) from nearby grain producing farms.

[99] District Energy St. Paul: http://www.districtenergy.com/about/story.html

Straw is supplied by farmers to the heating plant as Hesston bales, measuring approximately 1.2 x 1.3 x 2.2 meter (h x w x l) and weighing about 500 kg each. Storage takes place at the individual farm in a straw barn often erected solely for this purpose. Under roof storage is not exactly a requirement in the delivery contract with the district heating plant, but the requirement to supply dry straw with no soil can be met this way, and experiments with cheaper solutions such a open air storage with plastic covers has been abandoned.

The farmers store the straw from harvest in late summer (August) until it is needed at the heating plant (between September and July the following year). The 50 farmers who supply straw to the heating plant is organized in a straw supply association, which supplies straw to Thorsager as well as the neighboring town of Rønde. Formally the contract for straw supply is between this association and the district heating company. The annual consumption of straw is approximately 2,500 tonnes.[100]

Straw is commonly used this way in Denmark, where about 50 district heating plants use straw as a boiler fuel. A total of 236,000 ton of straw is utilized this way; this corresponds to about 22 % of the overall 1.06 million ton of straw used for energy in the country. Other fuels used in similar plants are wood chips, wood pellets and other wooden residues. A total of 120 district heating plants use solid biomass fuels as the main fuel source.

See Appendix B for more information.

District Energy Associations

A number of associations dedicated to promoting district energy exist in North America and around the world, providing resources, conferences and a forum for sharing results. Two of these, the Canadian District Energy Association (http://cdea.ca) and the International District Energy Association (http://www.districtenergy.org/index.asp) are of particular note.

"In 2008, district energy system growth has been strong, despite a challenging economy in the U.S. and beyond. Our members reported that 126 North American customer buildings totaling 39,897,947 sq ft of space were committed or recommitted to district energy service during 2008. An additional 9 buildings comprising 5,074,108 sq feet committed or recommitted to district energy service in 2007, but were previously unreported.

"The resulting North American total of 44,972,055 sq ft added to IDEA's running total of square footage of 422,714,867 sq ft committed to North American district energy systems since 1990, brings the current reported total for North America to 467,686,922 sq ft.

"IDEA is also pleased to be able to report solid system growth from beyond North America. An additional 275,319,145 sq ft and 2,815 buildings were reported for 2008 (Table 6.3)."[101]

[100] Case Study: Anders Evald, Force Technologies, Denmark. Dec. 2009
[101] International District Energy Association: http://www.districtenergy.org/de_space.htm

Table 6.3: IDEA - 2008 Square Footage Reported [102]

Category	North America	Beyond North America
Commercial-Mixed Use	8,711,625	136,932,609
Commercial-Office	10,086,498	17,507,536
Commercial-Retail/Manufacturing	90,554	3,754,565
Commercial-Other	1,286,400	6,725,934
Entertainment, Cultural or Sporting Center	1,061,200	64,200
Government	1,015,808	8,568,560
Hotel	4,812,855	16,266,625
Residential	5,702,193	92,050,910
School, Hospital or Institution	10,082,922	-0-
Other	2,122,000	-0-
Square Footage Reported 2008	**44,972,055**	**281,870,939**
2008 Total Reported in North America and Beyond North America	**326,842,994**	

Note: All entries are newly signed, connected or renewed customers during calendar year 2008,except for 5,074,108 sq feet previously unreported for calendar year 2007. *(Renewal* = renewed/recommitted to a long-term service agreement of 10 years or greater.)

Developed by NRCAN, RETScreen[103] is a modelling tool which provides information on the feasibility of many renewable energy systems including biomass. Also included in the tool are examples of the types of systems it can model, and a summary of the biomass heating applications is included below (Table 6.4). These examples include both district and facility specific heating systems.

[102] International District Energy Association: http://www.districtenergy.org/de_space.htm
[103] NRCAN – RETScreen: http://www.retscreen.net/

Table 6.4: Summary of RETScreen Biomass Heating Case Studies[104]

City			Ouje	Penticton		Kapuskasing	Charlottetown	Renfrew	Ljubljana/B
Province/Country				BC	UK		PE	ON	Slovenia
Heated floor area for building		m²	5,750	4,050	`	16,100	8,000	250	29,000
Heating load for building		W/m²	70	73	67	109	100	240	78
Domestic hot water heating base demand		%	10%	0%	10%	21%	10%	88%	51%
Total heating		MWh	1,028	622	1,378	5,040	2,043	912	9,300
Base load heating system									
Capacity	Base Case	kW	402.5	295.7	605.0	1,748.8	800.0	60.0	2,255.0
	Proposed		250.0	600.0	300.0	1,500.0	350.0	150.0	2,300.0
Heating delivered	Base Case	MWh	1,027.9	622.3	1,378.4	5,040.4	2,042.7	912.1	9,300.5
	Proposed		986.7	622.3	1,325.2	5,004.8	1,741.2	904.3	9,300.5
Fuel type	Base Case		Diesel	Natural Gas	Diesel	Nat Gas	Diesel	Elect	Diesel
	Proposed		Biomass	Biomass	Biomass	Biomass	Biomass	Biomass	Biomass
Seasonal efficiency	Base Case	%	60%	65%	65%	75%	74%	100%	60%
	Proposed		80%	50%	70%	68%	63%	65%	85%
Annual Fuel cons.	Base Case	m³	160,698	91,937	210,391	711,801	304,137	912	1,537,836
	Proposed		225	227	370	1,216	429	253	2,136
Fuel rate	Base Case	$/m³	0.450	0.350	0.600	0.330	0.400	0.070	0.630
	Proposed		11.667	0.000	45.455	10.000	214.727	-24.286	121.667
Fuel cost	Base Case	$	72,314	32,178	126,234	234,894	121,655	63,850	968,837
	Proposed		2,622	0	16,796	12,158	92,050	-6,156	259,838
Peak load heating system									
Suggested capacity		kW	152.5	0.0	305.0	248.8	450.0	0.0	0.0
Capacity		kW	200.0	0.0	750.0	1,500.0	450.0	0.0	200.0
Fuel type			Diesel	Nat Gas	Diesen	Nat Gas	Diesel		Biomass
Seasonal efficiency		%	80%	0%	65%	75%	82%	100%	85%
Fuel consumption - annual		m³	4,831	0	8,119	4,555	34,492	0	0
Heating delivered		MWh	41.2	0.0	53.2	35.6	301.5	7.9	0.0
Fuel rate		$/m³	0.450	0.000	0.600	0.330	0.400	0.070	0.000
Fuel cost		$	2,174	0	4,872	1,503	13,797	0	0
GHG emission		tCO2							
Base case			432	171	565	1,327	817	394	4,130
Proposed case			21	8	35	51	108	9	75
Gross annual GHG emission reduction			411	163	530	1,276	709	385	4,055
Initial costs		$							
Power system			0.0%	0	0	0	0	0	0
Heating system			364,672	300,000	217,645	1,234,138	97,642	50,850	927,600
Other			113,292		43,984	168,814		16,130	348,351
Total initial costs			477,964	300,000	261,629	1,402,952	97,642	66,980	1,275,951
Incentives and grants		$	0.0%	75,000					
Cost per kW		$	1,187	1,015	432	802	122	1,116	566
Annual costs and debt payments		$							
O&M (savings) costs			14,037	5,796	3,960	27,600		1,980	92,470
Fuel cost - proposed case			4,795	0	21,668	13,661	105,847	-6,156	259,838
Debt payments - 0 yrs			43,814	0	31,192	115,527	7,318	6,540	105,100
Other				2,400					
Total annual costs			62,646	8,196	56,820	156,789	113,164	2,365	457,408
Annual savings and income		$							
Fuel cost - base case			72,314	32,178	126,234	234,894	121,655	63,850	968,837
Total annual savings and income			72,314	32,178	126,234	234,894	121,655	63,850	968,837
Financial viability		Yr							
Simple payback			8.9	9.4	2.6	7.2	6.2	1.0	2.1
Equity payback			3.7	8.5	0.7	4.0	2.2	0.4	0.5

* Note: The green line above is a calculation not provided by RETScreen.

[104] NRCAN RETScreen: Summary of Case Studies -http://www.retscreen.net/

From an analysis of this data, the following conclusions can be drawn:

- The variation on heated floor space provides a broad overview of the impact of biomass fired heating projects
- The majority of the cases prioritize space heating (vs. domestic hot water)
- Heating needs per square foot appear to be relatively consistent, with the more northern Canadian locations (with the exception of Renfew) in at around 100 W/m2 and the rest at 70 +/- 10%
- The seasonal efficiencies (whether base case or proposed) vary a good deal from the typically higher numbers given by boiler/gasifier system manufacturers – a critical point when designing systems
- The cost per kW (green line) varies significantly from a low of $122/kW (PEI) to a high of $1,187 (Ouje)
- All the systems resulted in a less than 10 years simple payback period, with an average of 5.5 years. For a public infrastructure investment involving a renewable energy system, this is highly acceptable.

6.4 Denmark

Material for this section was provided by Force Technologies of Denmark.[105]

Policy

The main objectives of Danish energy policy are:

- *Security of energy supply*
- *Environmental and climate aspects of the use of energy*
- *Cost effectiveness of energy supplies*

In order to realize these goals various policies are being followed by the Danish Government, including the development of new energy technologies.

History

Being 100 % dependent on imported oil in the early 1970s the Danish Government has since increased efficiency in use of energy through energy planning and other initiatives which have led to increased use of waste heat from power stations and to a strong growth in district heating. Other initiatives have led to increased use of renewable energy, including biomass and waste.

One result of the policies initiated is that Danish companies and research institutions today are internationally acknowledged for the development of new energy technologies. The Danish export of energy technology has in recent years grown faster than overall Danish exports and today energy technology exports constitute approximately 10 % of the total Danish exports (2008).

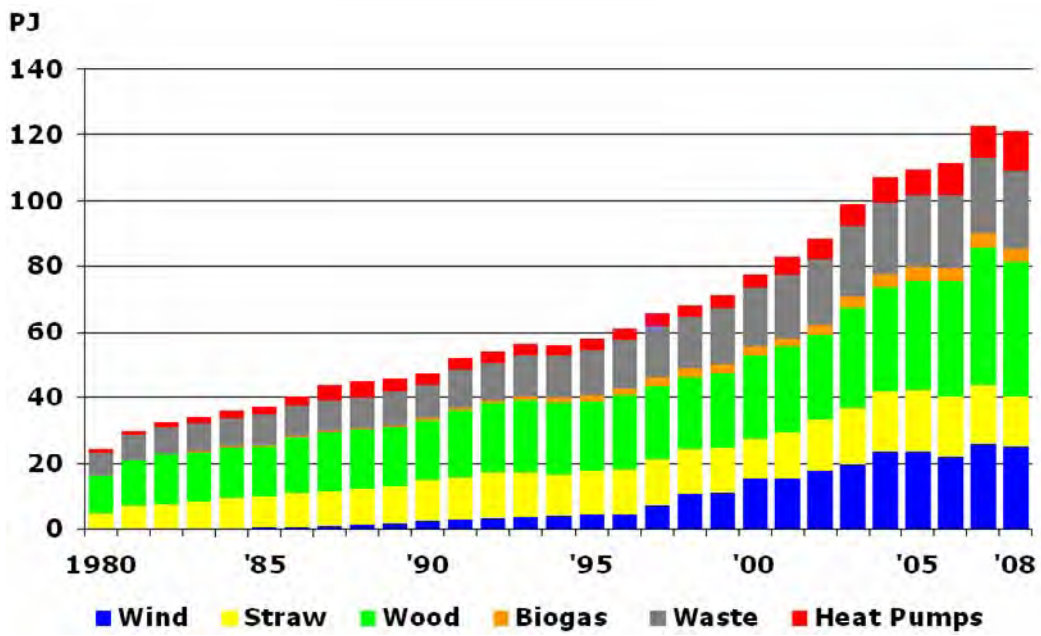
Biomass

A series of national energy planning efforts since the late 1970s put strong focus on the introduction of renewable energy (RE). Even though other RE sources gain more political attention and are far better understood by the general public, solid biomass fuel has carried the largest part of the development of RE.

[105] Anders Evald, Force Technologies, Dec 2009

In Denmark, biomass currently accounts for 70 to 75 % of renewable-energy consumption, mostly in the form of straw, wood and renewable wastes, while biogas accounts for less. Consumption of biomass for energy production in Denmark more than quadrupled between 1980 and 2005.

Figure 6.6: Renewable Energy Supply - Denmark[106]



Contribution of the different RE sources to energy supply in Denmark. Total energy consumption is 868 PJ (source: Danish Energy Agency, 2009)

Renewable energy accounts for 13.8% of Denmark's total energy use. Agricultural and forestry biomass constitute 50% (approximately 60 PJ) of the total 120 PJ produced by Denmark's RE.

Energy taxes

High taxes on fossil fuels were introduced in Denmark in the mid-1980s. Consumers in Denmark are used to high prices on electricity and heating and transport fuels, and the high energy prices has been the foundation for the strong development of RE and energy savings for the past 25 years. The costs for this indirect subsidy are paid by the energy consumers.

In rough numbers, the energy tax and carbon dioxide tax together account for about 50 % of the fuel cost for oil or gas paid by private consumers. Fossil fuels used for the production of goods are exempt from the energy tax, thus biomass fuels are less competitive in industrial applications than in applications for private heating e.g. in a district heating system.

[106] Danish Energy Agency 2009

Subsidy for electricity on RE

In power plants the situation is different from the above mentioned energy tax scheme. For combined heat and power plants, a fraction of the fuel consumption is allocated to the heat production and subject to the above taxes. For the rest of the fuel and for the total fuel consumption in dedicated power plants, a different range of schemes apply.

The driver for the majority - in terms of volume - of biomass power in Denmark is a specific scheme set up by the Folketinget (parliament) in the early 1990s. This scheme simply requires power plants to use a certain amount of solid biomass annually (currently 1.4 million tonnes/year).

In early 2008 this figure was increased with an additional 0.7 million tonnes per year as part of a political agreement that allows for increased coal use in power plants earlier restricted through legislation.

Added to the political pressure in this system, power companies also receive up to 3 different bonuses for using biomass for electricity production:

1. *A fixed/guaranteed minimum tariff for renewable electricity, which includes the market value of electricity (the actual wholesale price) as well as a subsidy element up to the fixed minimum tariff in the case where market value is less than the fixed guaranteed tariff. Biomass electricity is eligible to this bonus for 100 % of the biomass based kWh determined trough allocation of the total fuel consumption on an energy basis.*
2. *A Renewable Electricity bonus of 0.10 DKK/kWh (for newer plants 0.15 DKK/kWh) (exchange rate: 1 DKK = 0.21 CAD, November 2009). Biomass electricity is eligible to this bonus for 100 % of the biomass based kWh determined through allocation of the total fuel consumption on an energy basis*
3. *A subsidy per ton on biomass used, between 0 DKK and 100 DKK pr. ton, distributed to eligible power plants and calculated from a need-principle based on the economic performance of the individual plant (biomass type and price, installation type, electric efficiency).*

All costs associated with these schemes are part of the utilities' common Public Service Obligations. This way the costs are distributed to the electricity consumers in Denmark.

In addition the EU carbon dioxide quota system adds value to electricity produced from renewables, further enhancing the incentives for power production in co-firing and dedicated biomass plants.

Market overview

Solid biomass fuels are used for energy in many different forms, and in many different applications, from wood stoves to power plants.

The main solid biomass fuels are

- *Firewood*
- *Wood pellets*
- *Wood chips*
- *Industrial wood waste*
- *Straw*
- *Municipal solid waste (MSW), of which the organics fraction, app. 80 % is accounted for as renewable*

Firewood is used in about 600.000 wood stoves, wood boilers and open fireplaces in Danish homes and summer cottages. Present consumption is 2-3 million m3 of solid wood. Wood pellets are used in power plants as a substitution for coal, in about 30 district heating plants, and in boilers in private homes. The national consumption is now more than 1 million metric tons, of which 85 % is imported.

Wood chips are used in about 70 district heating plants, in combined heat and power plants and to an increasing extent in industries as a substitution for oil, coal or natural gas. Present consumption is about 1.5 million metric tons (measured as moist chips at 45 % average moisture content total weight basis). Industrial wood waste is mainly used by the wood industries themselves. The total consumption for energy is about 0.4 million ton (measured as a mostly dry material at 20 % average moisture content total weight basis).

Straw is used in power plant for co-firing with coal, in smaller combined heat and power plants, in about 50 district heating plants and in more than 5,000 farm scale boilers for heating of farm houses, drying of grain etc. The total consumption of straw is about 1.1 million metric tons.

MSW is burned in modern waste incinerators where the heat released is used for electricity and heat production. 70 waste incineration boiler lines exits in Denmark in 30 locations burning about 3 million metric tons of MSW annually.[107]

6.5 Summary

Biomass to heat applications work – and have proven themselves in many parts of the world, particularly in Europe. The success of these systems is due to a combination of factors including:

- Leadership – an influential proponent/group is required to lead and drive the initiative
- Biomass availability – the feedstock needs to be close to the facility in question
- Technology – use of established technologies (e.g. boiler systems) helps to reduce the variables and keep the systems running well
- Planning – integration with existing heating systems (municipal and within each facility) is critical for long term system viability
- Policy – governments have a role in making the growth of these systems possible, and can impact energy decisions with GHG policies, sustainability plans, taxes and incentives

The short term prospects for biomass heating applications in Manitoba are a continuation of growth into the greenhouse sector and Hutterites colonies as the established markets. New applications will include communities/businesses located near to biomass processing facilities (forestry or agriculture) as well as the potential for reserves and other rural locations near forest biomass resources. Longer term prospects are new housing and urban developments which will require new infrastructure, combined with policies which discourage continued reliance on fossil fuels. Other long term prospects include industrial facilities which process biomass to actually use it in their own facilities to provide heat and/or power. More detail on these scenarios is included in Table 8.1.

[107] Anders Evald, Force Technologies, Dec 2009

7 Environmental Implications

This section highlights the environmental implications of the removal of biomass for conversion to heat energy must be considered in any program to ensure that levels of soil productivity and carbon content be maintained for long term sustainability. Other issues including erosion, wildlife habitat and potential increased use of fertilizers to make up for the loss of nutrients with biomass removal must also be considered.

Agriculture

The impact of removing agricultural biomass residues on soils is complex and depends upon a large number of interactive factors (gathered from the sources cited below):

- Land Management: No till vs. ploughing
- Soil Composition: Sandy vs. loam vs. clay content in soil
- Erosion: Sloped vs. flat fields
- Climate: Wet vs. drier climate zones
- Fertility: River bottom areas vs. less fertile zones
- Annual Moisture: Dry year vs. wet year

Assumptions in this report are that for agricultural biomass, up to one third of the crop residues can be taken without impacting overall crop production in the more fertile areas of Manitoba: Red River Valley, Interlake and the Swan River area. The current situation is that many of these residues are presently being burned, resulting in significant air emissions that can be greatly reduced by using these resources to provide heat.

"To be sustainable, residue must only be removed when soil quality will not suffer as a result. In some regions the combination of crop, management practice, soil, and climate work together to produce more than is needed to maintain soil health. In this case, excess residues could potentially be used for conversion to biomass energy. However, for many other cropping, soil, and climate combinations (especially in warm regions), residue production is inadequate even for basic soil protection (Parr and Papendick, 1978). It is important to discern in what systems residue harvest is possible, or even beneficial, and at what rates (Table 7.1).

Table 7.1: General Guidelines for Sustainable Residue Harvest[108]

Sustainable harvest amounts will vary by:	Residue harvest rates should DECREASE with:	Recommendations for sustainable residue harvest:
Management practice	Increased soil disturbance	Use no-till with cover crops
Crop & yield	Lower yield or lower C:N	Harvest high residue crops and only in good yield years
Climate	Warmer, wetter climate	Residue harvest in the US SE is high-risk
Soil type	Coarser soil texture	Heavy clay, poorly drained soils are good candidates
Topography	Greater slope	Use a variable rate harvester or stay off hillsides and eroded knolls

Example: Corn Stover

"For the harvesting of corn stover as a biofuel feedstock to be sustainable, some of it must be left behind: complete removal of stover would have a seriously detrimental effect on the land.

"There are several considerations:

- *Soil Erosion. Crop residues help prevent water and wind erosion. Cultivation practices that leave stubble, as opposed to simply loose residue, are effective at limiting erosion. Soil texture, field slope, tillage practice and crop rotation methods all have an effect on the amount of stover that needs to be left behind to reduce soil erosion. A recent study estimated that, out of 40 million tonnes of corn residue produced in Iowa in 1998, 16 million tonnes, or 40 percent, could safely be removed under conventional tillage practices and 24 million tonnes, or 60 percent, under no-till practices. (Savoie and Descoteaux, 2004)*

- *Organic Matter and Nutrients. Removing too much corn stover can reduce the amount of carbon stored in the soil and therefore have a negative impact on soil fertility and crop productivity. Three quarters of new carbon that moves into soil from plant residues comes from the plant's roots, and only 25 percent from surface residue. Two-thirds of the carbon contained in the surface residue is actually released into the atmosphere rather than making it into the soil (Hettenhaus, 2004).*

"However, that one-quarter from the surface residue is still important. In an Ohio State University study (published in 2007) researchers removed corn stover at different rates (0, 25, 50, 75 and 100 percent) at three sites over three years. They found that removing corn stover was particularly harmful in silt-loam soils on undulating terrains, and less so in clay soils on flat terrain. Removing anything more than 25 percent from sloping soils significantly reduced soil carbon concentrations; as much as 75 percent could be removed from clay soils in flat terrain without a negative impact showing up over the course of the study. In the study, removing up to 50 percent of corn residue from sloping

[108] USDA – Crop Residue Removal for Biomass Production: http://soils.usda.gov/sqi/management/files/sq_atn_19.pdf

lands decreased yields by an average of 1,740 pounds (about 31 bushels) per acre (Pollock, 2007)

"In cold climates such as Canada's where, as noted earlier, too much stover left on the field can keep the ground from warming and drying enough for seeding, stover is currently often ploughed under. Because zero-tillage allows stover to be removed, this ploughing can be eliminated. Eliminating ploughing has a number of benefits. Ploughing often results in a burst of carbon dioxide into the atmosphere as the organic material in the soil oxidizes upon being ripped open and exposed to the air. The amount of stover ploughed into the soil in the process is often insufficient to replace that lost carbon.

"As a result, a field currently being tilled conventionally, with the stover being ploughed under, may actually gain soil nutrients if it is switched to zero-tillage and the stover is largely removed (Hettenhaus, 2004). In order to ensure the health of the soil, therefore, fields where corn stover is being harvested need to be carefully monitored. In addition to looking for visual signs of erosion or crusting, farmers should conduct periodic checks of soil carbon, and adjust the removal of stover (and application of fertilizer) as necessary."[109]

"PAMI did a study to provide better data on the straw to grain (S/G) ratio of wheat throughout the province. This data was collected prior to swathing, before and after combining, and after baling. Data on long-term storage was also collected over a period of 14 months. Three important pieces of information were derived from this very timely and interesting study.

1. *On average, when normal practices are followed, only 48% of the total available straw is actually removed during baling, while the remaining 52% is returned to the land.*
2. *The S/G ratio data has been forwarded to PFRA, who are developing maps of straw availability based on this data and wheat yield data. These maps will help potential industrial straw users choose processing plant locations and determine capacities.*
3. *Round bales preserve straw quality and quantity better than small square bales, and that if the stack is not tarped, up to 40% of the straw could be lost due to spoilage."*[110]

Forestry

"Burning wood to produce energy is not inherently detrimental, and can in fact provide environmental benefits over the use of fossil fuels. The crucial issue is deciding what is safe to remove from the forest to fuel biomass energy production. The available science is clear that stand-wide whole-tree harvesting (i.e., removing branches, tops and foliage as well as stem wood) and removal of deadwood has significant detrimental impacts on soil nutrients, wildlife habitat and forest carbon storage. The straight-forward way to avoid these threats to forest sustainability is to leave the tops and branches of harvested trees in the forest, along with standing and fallen deadwood.

"Existing forestry guidelines and regulations recommend against removing tops, branches and deadwood from the forest due to the threats to forest sustainability. … The pressure to develop non-fossil fuel energy sources increases the popularity of burning 'waste'

[109] Agriculture Canada: http://www4.agr.gc.ca/AAFC-AAC/display-afficher.do?id=1226608711012&lang=eng
[110] Prairie Agricultural Machinery Institute: http://www.pami.ca/energy_and_processing.htm

forest biomass, such as branches, tops and otherwise unmarketable trees to produce energy. Indeed, wood has the potential to provide a relatively green, local and potentially carbon-neutral energy source. Wood can be burned to produce electricity, to heat residential and industrial facilities, and to derive products to store and transport energy (such as ethanol or bio-oil).

"… In terms of sustainable forest management, leaving tree tops, branches and foliage (logging slash) in the forest, along with maintaining standing and fallen dead trees, are two of the easiest and most effective actions forest managers can take to promote biodiversity and sustain a healthy, resilient and productive forest. For these reasons, forest certification requirements (such as under the Forest Stewardship Council or the Canadian Standards Association) discourage biomass harvesting.

"... Experience gained from European forests demonstrates the need for a conservative approach to biomass harvesting. For example, in the whole of Europe, species that depend on deadwood make up the largest single group of species at risk. Furthermore, research in Finland found that forest productivity following biomass harvesting dropped by approximately 10%.

"… Biomass harvesting also jeopardizes forest carbon stores by increasing the rate of carbon lost from forest soil. On average, soil tends to store two-thirds of all carbon found in a forest. Biomass harvesting can cause a decline of soil carbon by over one-third at time of harvest, and a recovery time of 60-80 years."[111]

Emissions and Biomass Storage

"Currently there are two areas of concern for biomass heating systems with respect to the environment; emissions and storage of the biomass. The current regulations state that particular matter emissions can be no greater than 0.23g/m3 and that only gasifiers and incinerators require a license. The licensing process also includes a public hearing. Boilers, on the other hand, do not require a license or permit. Boiler and gasifier manufacturers have indicated that they all meet these standards and could reduce their emissions further by using systems, such as cyclone filters, bag filters and electrostatic precipitators.

"(Steam projects and gasification projects are currently considered class 1 developments under the Environment Act (Manitoba Government, 1988). Combustion systems, such as boilers currently are not regulated.)

"Manitoba Conservation is in the process of developing changes to the current regulations that would address some of the differences (Coulter, 2009). The suggested changes could include the development of a new category "Thermal Treatment Technologies," where boilers, gasifiers, and incinerators would be grouped together. Each of the technologies would require a permit, but not a public hearing. There are also efforts underway to tighten the current emission standards to levels similar to stricter standards in other jurisdictions in North America.

"Manitoba has experienced some issues with large biomass storage facilities. The example of the straw storage near Elie, Manitoba has resulted in Manitoba Conservation thinking about potential limits to the volume of material stored by a commercial user who is not the original producer of the biomass. Although limits are not currently in place,

[111] Nova Scotia Ecology Action Centre: http://www.ecologyaction.ca/files/images/file/Wilderness/EAC%20Forest%20Biofuel%20Report%20Dec%2008.pdf

biomass users and processors should ensure their storage facilities do not create potential environmental hazards."[112]

Summary

The use of agricultural and forestry biomass for heating purposes has implications for the environment as:

- The biomass resources are no longer available for conservation or livestock use
- Emissions are created from the gathering, transportation, and processing of the biomass
- The combustion of the biomass itself generates emissions in addition to fly and bottom ash.

Any use of fuel has its energy cost and lifecycle, and the price of substituting renewable fuels for non-renewable ones also has a cost. The sustainable use of biomass means understanding these costs and weighing them against the alternative of maintaining the status quo.

Assumptions in this report are that for agricultural biomass, up to one third of the crop residues can be taken without impacting overall crop production in the more fertile areas of Manitoba: Red River Valley, Interlake and the Swan River area. The current situation is that many of these residues are presently being burned, resulting in significant air emissions that can be greatly reduced by using these resources to provide heat. For the forestry biomass, the residues being considered are those already being removed by the industry.

The topic of the environmental implications of biomass residue removal, whether agricultural or forestry, is a complex issue and dependent upon many site-specific factors. No body of information was found which could provide a simple, province-wide generalization on this topic which could benefit from further study.

[112] Tyrchniewicz Consulting (MAFRI): Biomass Conversion Feasibility Study 2009, p. 22

8 Manitoba Biomass Industry

8.1 Biomass Markets

Feedstock Supply
As stated in the feedstocks section of this report, Manitoba has a number of biomass suppliers with others developing materials or waiting for more favourable market conditions. These suppliers are able to provide sufficient fuel to the present users of biomass, but future growth in the biomass heating market will require additional capacity and additional biomass fuel suppliers. Some, like Can-Oats, are exporting a portion of their production to the USA.

Boiler and Stoker Manufacturing
Manitoba`s strength in this area are the Decker boiler and Blue Flame stoker manufacturers which have traditionally worked with coal burning units and are developing ways to use different types of biomass fuels. While a switch to oat or wood pellets appears to permit the same feed/stoker equipment used by coal, other feedstocks such as wood chips, sawdust, straw and larger densified products may require additional modifications. Ongoing innovation and modifications are being worked on in the Hutterite colonies to adapt to different types of biomass fuels in anticipation of the province's coal tax and market price changes. Other manufacturers who have operated in Manitoba in the past (for instance the whole bale burners) may emerge again if market conditions permit.

Commercial Biomass Consumers
"Manitoba has several good examples of … (solid fuel) biomass end users, including… Defehr Furniture (which) currently uses residual wood dust and larger pieces from the production of furniture to fire a 14 million BTU boiler for heating their complex. Simplot currently uses the residual material from their processing to feed an anaerobic digester to supply methane gas which they use to replace natural gas in their production process.

"(Other potential markets include)… *institutions, such as colleges, schools, hospitals, office buildings, factories etc. Some of the commercial users are also interested in establishing or keeping a "green" image by reducing their GHG emissions and reducing their dependency on fossil fuels.*

"Many of these users would be able to use available equipment to meet their needs, requiring little if any modifications. This will keep design costs down and provide proven equipment. The supply of biomass material will be a key issue for these users. Cost will be the key driver in having them switch to biomass, but another important variable for them will be the consistency of biomass supply and quality available. These users would benefit from a standard biomass fuel type designed for their biomass heating system.

"For commercial biomass users switching from coal or natural gas, infrastructure modifications will be necessary, such as sufficient dry storage for the biomass fuel. In most cases, the biomass boiler system will be able to use the existing heat transfer system.

"The coal replacement market is relative small by the energy consumed in Manitoba, but the substitute biomass material needs to operate effectively in the users' current systems with relatively minor modifications. Biomass used to replace natural gas requires equipment to new biomass heating systems with significantly more capital costs associated with it.

Small Biomass Consumers

"Small biomass consumers are those whose heating requirements are relatively small, such as farm yard or residential property. These users will be interested in reducing costs, but are also looking for convenience. Small biomass fuel users want a consistent product and will have little patience for supply issues. This could be considered a retail market for biomass solid fuel."[113]

Market Status and Projections

Projections are based on a highly restricted view of the future with the clear understanding that any look ahead can be based only on an extension of past trends. With that caveat, the following trends/theories have been considered in the creation of Table 8.1:

- Peak oil extending to peak gas
- Increased need for heat
- Maintained soil/forest fertility
- Increased political support for renewable energy sources – provincial renewable energy ratio targets developed
- Development of a carbon market to assist in the development of renewable technologies

The following chart (Table 8.1) provides an overview of Manitoba's present market status and ideas for projections as they relate to the various elements of the biomass to heat sector.

[113] Tyrchniewicz Consulting (MAFRI): Biomass Conversion Feasibility Study 2009, pp. 19-21

Table 8.1: Biomass Market Status and Projections

	Present Status and Development stage	5 year Projection	20 year Projection
Agricultural Biomass Feedstock	Processing residues: Oat hull pellets – Mature Sunflower hulls – Growing Flax shives – Growing	Processing residues: Oat hull pellets - Mature Sunflower hulls – Growing Flax shives – Growing	Processing residues: Oat hull pellets - Mature Sunflower hulls – Mature Flax shives – Mature
	Crop residues: Bales – mature Straw/stover densification – R&D	Crop residues: Bales – mature Straw/stover densification – Emerging/Growing	Crop residues: Bales – mature Straw/stover densification – Mature
	Energy crops: Switch grass – R&D	Energy crops: Switch grass – Emerging	Energy crops: Switch grass – Growing/Mature
Forestry Biomass Feedstock	Processing residues: Sawdust, wood chips – Mature Wood pellets – Emerging	Processing residues: Sawdust, wood chips – Mature Wood pellets – Growing/ Mature	Processing residues: Sawdust, wood chips – Mature Wood pellets – Mature
	Logging residues: Chunks, wood chips – Mature	Logging residues: Chunks, wood chips – Mature	Logging residues: Chunks, wood chips – Mature
	Construction, demolition residues : lumber – R&D	Construction, demolition residues : lumber – Emerging	Construction, demolition residues : lumber – Growing/Mature
	Energy crops: Willow, poplar – R&D	Energy crops: Willow, poplar – R&D	Energy crops: Willow, poplar – Emerging/Mature
Thermal Conversion Technology	Single stage combustion – Mature	Single stage combustion – Mature	Single stage combustion – Mature
	Dual stage combustion – R&D	Dual stage combustion – Emerging	Dual stage combustion – Growing/Mature
	Gasification for CHP (Imported) – R&D, Emerging (Nexterra), Growing (Ankur)	Gasification for CHP – all stages of development	Gasification (Not MB) – Mature
	Pyrolysis (Not MB) – mature (Preseco)	Pyrolysis (Not MB): mature (Preseco)	Pyrolysis (Not MB): mature (Preseco)
Biomass Heat Applications	Hutterite Colonies – Emerging/Growing	Hutterite Colonies – Growing	Hutterite Colonies – Mature
	Greenhouses – Emerging/ Growing	Greenhouses – Growing	Greenhouses – Mature
	Institutional, Commercial Industry – R&D	Institutional, Commercial Industry – Emerging	Institutional, Commercial Industry – Growing
	Small town district heating – R&D	Small town district heating – R&D	Small town district heating - Emerging
	City level district heating	City level district heating	City level district heating – R&D, Emerging

Summary

Manitoba's biomass feedstock markets are restricted to a small percentage of the total biomass available – that is densified and bulk agricultural processing residues, pelletized wood residue and woodchips. The current markets for thermal conversion equipment are restricted the mature stoker boiler technologies, with gasifiers making a projected entry in 2010. The market for biomass heating systems consists of Hutterite colonies and greenhouses due to their investments in hot water systems and ease in substituting fossil fuels with biomass.

8.2 Infrastructure

An evaluation of the biomass infrastructure in Manitoba involves examining what is needed to build and maintain the supports for the feedstock and thermal conversion technology processes. The components of Manitoba's biomass infrastructure (defined as the underlying functional framework of the system including the required services, facilities, physical and organizational structures) are listed in the chart below (Table 8.2). These consist of the systems (defined as all components such as manufacturing, distributing, maintaining, and general capacity) pertaining to the various stages in the lifecycle of converting biomass to heat:

- seed/seedlings
- planting/harvesting
- processing/densifying
- combustion/gasification
- heat transfer to buildings
- transportation
- roads/railroads
- energy
- ash/emissions by-products
- communications.

The following terms are used to describe the status of the various infrastructure components:

R&D:	Work just beginning, limited applications
Emerging:	Solid but few examples functioning
Growing:	More players, growing markets and standardization
Mature:	Multiple players, established markets, no additional work required in the immediate future

Table 8.2: Manitoba Biomass Infrastructure Analysis

Infrastructure Component	Agriculture	Forestry
Seed systems/providers: The systems to provide the seeds and seedlings necessary for the crops to be in place.	Conventional crops – Mature Fuel crops – Emerging	Conventional trees – Mature Fuel crops – Emerging
Planting/Harvesting Machinery chain: The equipment (and its developers, dealers and maintainers) necessary to plant, till and harvest the crops from which the biomass is derived.	Mature	Mature
Processing equipment chain: The equipment (and its developers, dealers and maintainers) required to convert the biomass into a product and handle it to the thermal conversion chamber (reduction, densification).	Baling/Stacking – Mature Densification – R&D/Emerging	Chipping, grinding – Mature Densification – Emerging
Thermal conversion equipment chain: The equipment (and its developers, dealers and maintainers) required to convert the biomass into heat	Stoker Boilers – Mature for densified feedstock Boilers for raw, unprocessed or baled feedstock – R&D Gasifier (N. America) – R&D Gasifer (India) – Growing	Stoker Boilers – Mature Bale burners – R&D Gasifier (N. America) – R&D Gasifer (India) – Growing
Thermal energy application chain: The equipment (and its developers, dealers and maintainers) required to transfer the heat to a usable medium, and transport that to where needed	Heat exchangers/ pumps/ controls/ underground piping/ installation/ maintenance – Mature	Heat exchangers/ pumps/ controls/ underground piping/ installation/ maintenance – Mature
Transportation - Equipment: The equipment (and its developers, dealers and maintainers) required to move the biomass from field to town, factory, home, greenhouse, community or other destination.	Trucks, trains, dealers, maintenance – Mature	Trucks, trains, dealers, maintenance – Mature
Transportation - Roads/Railroads: The condition and availability of these pathways to move the biomass	Primary, Secondary – Mature	To forestry resources – Seasonal access, rough
Energy systems - Transportation: The fuel (production, distribution of diesel, gasoline) required for transportation.	Mature	To forestry resources – Seasonal access

Infrastructure Component	End User
Energy systems - Heat: The energy (generation, distribution, transmission) required for heat/backup heat (natural gas, electricity, propane). This would provide the backup for biomass heating systems.	Electricity: Urban to rural – Mature Heat: Urban to large town areas (Natural Gas) – Mature Heat: Small town to rural – (Electricty, Propane) – Mature
Waste systems: The providers of air, water, and soil treatment equipment/handling for by-products of the biomass conversion to heat process: particulate matter and other emissions.	Emissions cleaning equipment : Emerging Fly and bottom ash: Emerging
Communication systems: The information pathways (transmission, lines, towers, receivers, connectivity) for telephone, internet and radio.	Urban to large town – Mature Small town to rural - Growing

Summary
The infrastructure to handle Manitoba's biomass sector is a combination of well established – where there are overlaps with existing capacity (roads, boilers, heating equipment dealers/installers, communications and the electricity network) and emerging – where aspects of the biomass sector are unique (densification, gasification). Priorities to building Manitoba's biomass sector capacity are investigating technologies to use raw, unprocessed or baled agricultural feedstocks, improve and grow densification capabilities, move quickly on research and development of fuel crops (both agriculture and forestry and develop air cleaning technologies to ensure low levels of emissions for units presently not covered by regulation.

8.3 Policy

The following section is largely taken from the Tyrchniewicz study, completed for MAFRI "Biomass Conversion Feasibility Study".

"Manitoba has had a longstanding commitment to address issues of climate change and reduction of greenhouse gas emissions. In the area of energy, Manitoba is a signatory to the Western Climate Initiative – a group of seven US governors and four Canadian premiers whose focus is to establish a regional greenhouse gas reduction goal and develop market-based strategies to achieve the goal. In September 2008 the Western Climate Initiative announced recommendations for the design of a regional market-based cap-and-trade program. The program will slash climate-changing greenhouse gas emissions, spur growth in new green technologies, help build a strong clean-energy economy and reduce dependence on foreign oil. The cap-and-trade design is an important element of a comprehensive regional effort to promote environmental sustainability and economic growth by reducing greenhouse gas emissions by 15 percent below 2005 levels by 2020.)

"The Manitoba Energy Development Initiative *includes a focus on developing clean energy in the areas of agri-energy, biofuels, geothermal, wind energy, green building and energy efficiency and hydrogen. A recent emphasis on renewable energy resources as a replacement for conventional fuels is creating a renewed demand for biomass. This is especially true in replacing coal with biomass sources of energy.*

"In its 2008 budget statement, the Government of Manitoba announced a new tax of $10 per tonne of carbon-dioxide-equivalent emissions will apply to coal effective July 1, 2011. The tax rate will subsequently be raised to $30 per tonne on a schedule to be announced in a future budget. The Province will also contribute up to 25% of private sector capital costs of investments to convert from coal, and will work with coal users to find appropriate substitutes.

"Manitoba Hydro Bioenergy Optimization Program
The focus of the program is to convert a company's waste streams and by-products into fuel that produces useful heat and power. The Bioenergy Optimization program enables customers to:

- *avoid electricity purchases;*
- *avoid fossil fuel purchases;*
- *avoid traditional waste disposal costs;*
- *save money, reduce carbon footprint and benefit the environment.*

"…Implementation incentives include capital costs associated with the design, purchase and installation of biomass-to-energy conversion equipment. Incentive amounts are based on 15¢ per kWh for annual electricity reduction and 30¢ per cubic metre for annual equivalent natural gas reduction. The incentive will not exceed 50 per cent of the eligible project costs or a maximum incentive of $1,000,000 on electrical load reductions and $250,000 on natural gas load reductions. Customers with the capability to incorporate customer-sited load displacement generation, combined heat & power (CHP), and renewable fuels, specifically biomass, into their operations are ideal candidates.

Federal Initiatives
"The Federal government has developed several programs to support the biofuel industry in Canada. On June 26, 2008, the Canadian Senate approved the Government of Canada's Biofuels Bill, which results in amendments to the Canadian Environmental Protection Act (Bill C-33) and gives the Government authority to establish regulations for renewable fuels, specifically mandating a 5 per cent renewable content in gasoline by 2010 and 2 per cent renewable content in diesel fuel and heating oil by 2012 (Government of Canada, 2008).

"Along with the biofuel mandates, the federal government also established 4 programs to assist biofuel producers and promote the production of biofuels:

- *EcoEnergy for Biofuels,*
- *NextGen Biofuels Fund,*
- *EcoAgricultural Biofuels Capital Initiative and the*
- *Biofuels Opportunity for Producers Initiative.*

"… All of these programs concentrate on advancing the production of biofuels. Part of the reasoning for these programs is to promote next-generation technologies. These technologies are capital intensive and the programs assist in the progression to market as they reduce some of the risk for financial investors.

"Potential Programs for Manitoba

This sub-section outlines some potential programs that could be offered or modified to promote the use of biomass solid fuels. This includes initiatives specifically focused on the operational implementation as well as a broader biomass energy strategy.

Operational implementations programs could take the form of:

- *Standardization of biomass pellets, cubes, briquettes*
- *Education including training biomass boiler operators and demonstration projects*
- *Research and development into biomass characteristics and equipment design*

"A biomass energy strategy for heating could be accomplished through the use of a number of broad policy instruments. These include regulations, subsidies and incentives and regulations.

Regulations can take a number of forms:

- *Standardization of pellets and equipment*
- *Requiring utilities to sell a minimum amount or percent of biomass based energy*
- *Mandating suppliers of energy to include a minimum amount/percentage of certain feedstocks, e.g., ethanol and biodiesel*
- *Prohibiting or limiting the use of certain energy feedstocks, e.g., coal*
- *Mandating the use of biomass technology in government owned/operated facilities*
- *Subsidies/incentives*
- *Long term, low interest financing for the implementation of biomass technology, including new equipment or upgrading existing equipment*
- *Assistance in establishing new generation cooperatives for suppliers of biomass feedstock to assure a stable supply of feedstock to biomass energy users*

"Taxation can take many forms:

- *Carbon taxes either broad or specific, e.g., coal – many European countries already do this*
- *Tax exemptions for the installation and use of equipment that burns biomass feedstocks*
- *Special Depreciation Rules for Biomass Energy Facilities*
- *Tax rebates/holidays for end users of biomass based energy*
- *Cap and trade*

"Developing a comprehensive biomass energy strategy and initiating a series of regulatory, incentive and taxation program should be undertaken in a structured rather than ad hoc manner. A key step is to apply a set of policy criteria to the range of policies and instruments. Some of these criteria include:

- *Equity criteria among suppliers and users of the biomass energy - Equity should not be interpreted as equality*
- *Implementation and enforcement efficiency - Costs and enforceability are very important criteria for policy efficiency. The efficiency will be low for policy instruments focusing mainly on legal actions for their implementation or requiring sophisticated and costly monitoring.*
- *Political acceptability - The acceptability of a policy instrument for environmental protection can vary significantly between interest groups. A policy that is strongly unacceptable for one or more of the interests or provokes polarization will be rated lower. The social and political context can also vary between jurisdictions.*
- *Environmental benefits - Significant measurable environmental benefits should accrue from the adoption and implementation of the policy instrument.*

- *Overall administrative, environmental and economic efficiency - This criterion integrates the overall efficiency and feasibility of the policy instrument.*
- *Appropriate scientific rationale underpinning the choice of policy instrument."*[114]

Summary:
The biomass/bioenergy industry in Manitoba is not being built on the back of government incentives, policy, planning and directives - but on market based choices. Other than a tax being levied to reduce the amount of coal, the provincial and federal governments are doing little to assist the growth of biomass heating from a financial or policy perspective. Manitoba Hydro's program helps only those who are investing in CHP which assists those willing to install equipment that is, in North America, still in the R&D stages, and which requires the capacity to manage a more complex system involving heat and power generation.

Policies regarding air emissions have resulted in some unintended consequences. Large producers of solid biomass fuel like Can-Oats originally produced it for their own process heat needs, but with present regulations it became prohibitively expensive to use. The fuel is being sold to many smaller users, with an unknown collective emission result.

The Danish experience (Section 6.4) carries a very firm message that in order for renewables to gain significant market traction, proactive government policies are required to envision the future and to create policies which reward the utilization of local, renewable resources like biomass.

8.4 Partnerships and Investment

As this report has shown, Manitoba has a plentiful biomass supply, and a large requirement for heat. In addition, a number of existing and emerging technologies to convert biomass to heat are available. The question then emerges, given these conditions, why is there not more use of biomass for heat in Manitoba?

A number of responses can be offered, including low fossil fuel energy prices and lack of government incentives, but even if these conditions changed, significant new partnerships and investments would need to exist to increase Manitoba's use of biomass for heat. These partnerships could involve various levels of government, Manitoba Hydro, industry, farmers, builders and developers – as well as governments and industry outside of North America. Successful partnerships require financing from existing financial institutions which would in turn require knowledge of concepts like biomass heat and district heating systems, and access to the global network of biomass experience and expertise.

Partnerships are being developed on many fronts between the Manitoba Government and Manitoba Hydro and between Manitoba Hydro and a number of its customers interested in developing new biomass fuelled technologies. These include the Manitoba Hydro pilot projects being developed with gasification, bio-oils, anaerobic digestion, organic rankin cycle and biocarbon. (More on these projects can be found in Section 8.5.) Partnerships exist and are being developed between various manufacturers of

[114] Tyrchniewicz Consulting (MAFRI): Biomass Conversion Feasibility Study 2009, pp. 26-29

biomass to heat technologies to extend the use of their technology to include a wider variety of feedstocks, as well as the exploration of large scale feedstock densification and CHP in Manitoba.

More work needs to be done to build partnerships and investments to grow the biomass sector in Manitoba which may involve growing new feedstocks, expanding the scope and size of biomass conversion technologies and developing new applications for biomass heating. A full exploration of this topic is outside the scope of this report, but will further explored as Provincial biomass to heat applications develop.

8.5 Research and Development

The field of biomass is a rapidly growing area of study and business in Manitoba and across North America. Unlike other renewable (solar, wind) energy sources which require storage mechanisms to deliver the energy after the sun has set or the wind has died down, biomass is in itself a storage of energy. As Vidir BEST puts it: biomass is "Sequestered Solar Energy". And as public and political awareness of global climate change grows, so do demands for alternative methods of providing for our energy supply, which in Manitoba is primarily composed of non-renewable energy resources.

Biomass is and has been a chief base load alternative with the ability to provide long term reliable power to rural or urban applications with locally grown energy. Research and development in any field is dependent upon many factors including: interest, money, time and the right moment. That moment is now for biomass for North America riding on political awareness of the need to build alternative energy capacity and what we know now about "peak oil." Interestingly, however, the "biomass moment" occurred 10-15 years ago in Europe, which fortunately for North America, provides us with the opportunity to learn from their experience and their example.

To cover the work of Canadian R&D in biomass is not possible in this space, but suffice it to say that many players are working hard to create answers to how the huge variety of biomass sources in Canada can be converted to heat, cooling and power. This list of R&D projects was encountered in the process of creating this study and includes both the creation of first-run models as well as first-time installations in Manitoba (both planned and underway):

- Conversion of Decker boilers to woodchips (Rock Lake)
- Installation of a woodchip boiler to heat a greenhouse (Pineland Nursery)
- Dual-stage combustion of straw (Vidir BEST)
- Canola and wheat straw pellets and cubes (Prairie Bio-Energy)
- A Brayton hybrid cycle to use an indirect fired micro turbine to produce heat and power (University of Manitoba)

Manitoba Hydro has five biomass demonstration projects currently underway[115]:

- *Pyrolysis oil:* demonstrating the use of a biomass-derived liquid fuel for industrial steam production, combined heat and power (CHP) generation, and agricultural applications.
- *Gasifier:* demonstrating a combined heat and power (CHP) system fuelled by syngas from a biomass gasifier using a downdraft microgasifier.

[115] More information can be obtained from Dennis St. George at Manitoba Hydro

- *Organic Rankine Cycle:* demonstrating the production of electricity from a low-temperature heat source using an Organic Rankine Cycle (ORC).
- *Anaerobic Digestion:* demonstrating a combined heat and power (CHP) system fuelled by biogas from an anaerobic digester.
- *Biocarbon:* demonstrating the production of bio-carbon as a replacement fuel for lignite coal utilized for heat and power applications and to utilize the waste heat from the carbonization plant manufacturing the bio-carbon for community heating.

Although not in Manitoba, it is relevant to mention the Energy and Environment Research Centre (EERC) in Grand Forks does work in renewable energy technologies including gasification.

Summary
Research and development activities in Manitoba directed to the biomass/bioenergy sector are examining not only present options and expansion, but future opportunities. The proximity of EERC and the engineering/technical capacity of Manitoba's universities provide the potential of greatly increasing the amount of work that is being done in this area.

8.6 Summary

Manitoba's biomass feedstock markets are restricted to a small percentage of the total biomass available – that is densified and bulk agricultural processing residues, pelletized wood residue and woodchips. The current markets for biomass thermal conversion equipment are dominated by stoker boiler technologies, with gasifiers making a projected entry in 2010. The market for biomass heating systems consists of Hutterite colonies and greenhouses due to their investments in hot water systems and ease in substituting fossil fuels with biomass.

The infrastructure to handle Manitoba's biomass sector is a combination of well established – where there are overlaps with existing capacity (roads, boilers, heating equipment dealers/installers, communications and the electricity network) and emerging – where aspects of the biomass sector are unique (densification, gasification). Priorities to building Manitoba's biomass sector capacity are investigating technologies to use raw, unprocessed or baled agricultural feedstocks, improve and grow densification capabilities, move quickly on research and development of fuel crops (both agriculture and forestry) and develop air cleaning technologies to ensure low levels of emissions for units presently not covered by regulation.

The biomass/bioenergy industry in Manitoba is not being built on the back of government incentives, policy, planning and directives - but on market based choices. Other than a tax being levied to reduce the amount of coal, the provincial and federal governments are doing little to assist the growth of biomass heating from a financial or policy perspective. Manitoba Hydro's program helps only those who are investing in CHP which assists those willing to install equipment that is, in North America, still in the R&D stages, and which requires the capacity to manage a very complex system involving heat and power generation.

Policies regarding air emissions have resulted in some unintended consequences. Large producers of solid biomass fuel like Can-Oats originally produced it for their own process

heat needs, but with regulations the way they are, became prohibitively expensive to use. The fuel is being sold to many smaller users, with an unknown collective emission result.

The Danish experience (Section 6.4) carries a very firm message that in order for renewables to gain significant market traction, proactive government policies are required to envision the future and to create policies which reward the utilization of local, renewable resources like biomass.

Although primarily research based, the partnerships developed in Manitoba are providing valuable assistance to businesses looking to displace fossil fuel heating with biomass. Research and development activities in Manitoba directed to the biomass/bioenergy sector are examining not only present options and expansion, but future opportunities. The proximity of EERC, PAMI and the engineering/technical capacity of Manitoba's universities provide the potential of greatly increasing the amount of work that is being done in this area.

9 Conclusions and Recommendations

9.1 Sensitivity Analysis

In order to make a decision as to whether or not using biomass for heating makes sense, there are many criteria to examine which include: type of application, facility location, type, location and storage of feedstock, financial incentives, thermo-chemical conversion technology and feedstock fit, emissions and community involvement. Given that these sensitivity criteria are numerous, and complex, the following chart was created to both display the extent of each one as well as to extrapolate what types of applications might be best suited for biomass heating (Table 9.1).

Table 9.1: Application of Sensitivity Criteria for Biomass Heat

Criteria	Detail	Small Commercial	Hutterite Colony/ Greenhouse	Small Town/ Institution/ Reserve	Industry
Application	• Residential, commercial, institutional, or community heating applications • Existing or new system • Future expansion plans • Auxiliary or primary system • Heating, Cooling, CHP • Heat: water, steam • Peak or base load	• Small commercial • Hot water system • Base load	• Small commercial/ agricultural • Hot water system • Base load	• Community district heat: commercial, institutional • New hot water heat • Primary, base load system	• Agriculture or Forestry industry • Hot water or steam • Base load
Location: Facility(ies)	• Rural or urban • Proximity of primary roads or railroads	• Rural • Adjacent to biomass processing facility	• Rural • Close to primary road • Facilities within 1 km of boiler	• Small town • Close to primary roads & RR • Facilities within 2 km of boiler	• Rural • Urban
Feedstock: Type / Location	• Energy value • Feedstock processing • Densification options	• 17 MJ/tonne • No processing or densification	• 17 MJ/tonne average • Densified fuel options	• 17 MJ/tonne average • Densified fuel options	• 17 MJ/tonne average • Densified fuel options
	Forestry • sawmills, pulpmills, peat processing • loose: chunk, sawdust, hogfuel • densified: pellet, puck, cube, log • fuel crops	• Sawmill: sawdust and woodchips (5 km) OR	• Wood chip (50 km) OR	• Wood chips (50 km) • Wood pellets (50 km)	• Sawdust, woodchips (onsite) OR
	Agriculture • agricultural processing centres • loose: straw, shives, hulls • densified: pellet, puck, cube • fuel crops: oil seeds, switch grass	• Flax processing: shives (5 km)	• Oat processing: hull pellets (50 km)	• Oat pellets, Sunflower hulls, Flax shives (50 km)	• Agriculture processing residues (onsite)

	• animal bedding				
Feedstock: Storage	• Availability of feedstock on an annual basis: seasonal, constant supply • Days storage required • Space required: immediate, expansion	• 3 - 7 days storage • constant supply	• 7 – 10 days storage • constant supply	• 7 – 14 days storage • constant supply	• 1-2 days storage • constant, reliable supply
Financial Incentives	• Grants (capital), Low interest loans • Carbon trading • Potential to sell heat/power	• Grants (capital)	• No grants	• Grants	• Tax breaks
Thermal Conversion Technology	• Maturity • Market penetration • Capacity (support, repairs, response)	• Mature • Well supported	• Mature • Well supported	• Mature • Well supported	• Mature • Well supported
	Thermo-chemical • Direct combustion (heat) • Dual stage combustion (heat) • Gasification (heat, cool, power) • Pyroloysis (heat, cool, power)	• Stoker boiler	• Stoker boiler	• Multiple stoker boilers	• Single large or multiple stoker boilers • Gasifier
Feedstock: Use	• Feedstock fit for conversion technology • Feedstock modification: grinding of densified fuel • Multiple feedstock use	• Sawdust/ woodchips OR • flax shives	• Woodchips OR • Oat pellets	Multiple feedstock use, no modification required	Multiple feedstock use
Emissions	• Emissions management • Types produced • Efficiency vs. emissions • Seasonal efficiency **Emissions regulations** • relative to size of operation • fly/bottom ash • being planned • air, soil, noise, water	• Air filtration system • Small enough not to qualify for emissions controls	• Air filtration system • Small enough not to qualify for emissions controls	• Air filtration system • Will likely qualify for emissions controls	• Air filtration system • Emissions controls
Community Involvement	• Interest/opposition • Need for PR	• NA	• Community support	• Community support	• Community support

Based on the above analysis, the best applications for biomass heating would be:

- A business/small community in a rural location requiring process and/or space heat situated close to a sawmill using woody biomass. This would involve the simplest and most mature conversion technology (boiler/stoker boiler) heating water, with the proximity of fuel (little transportation/logistical issues) with the uniformity of fuel type (woodchips/sawdust) available year round.
- A Hutterite colony (typical of those already established) and/or greenhouse using a boiler heating water using processed agricultural biomass (oat hull pellets) and/or woodchips requiring minimal storage (7-10 days) based on fuel reliability, and community support.
- A small town district heating a number of community/commercial buildings within a two km radius using as local as possible a fuel source (agricultural or forestry) combusted in a boiler heating hot water.
- A biomass processing facility using its own by-product for heat – e.g. Tembec, Can-Oats.

9.2 Conclusions

1. Manitoba's existing low energy price structures do little to encourage alternative renewable energy technologies, although the new coal tax is a step in the right direction.
2. Manitoba's renewable energy ratio (percentage of its energy use that is renewable) has not changed significantly in the past 20 years.
3. Solar thermal and wind can provide significant amounts of energy but require a backup energy resource which biomass can provide as a base load heating resource.
4. Manitoba's biomass resources are sufficient to provide for a majority of the Province's heating needs.
5. The biomass which is now being used for heat is primarily by-products from agricultural and forestry processes.
6. The majority of Manitoba's agricultural and forestry biomass resources are not used for heating purposes.
7. Manitoba's forestry biomass represents a huge renewable resource which has the potential to play a larger role in the Provincial energy picture. The greatest economic potential for forestry biomass has historically been lumber and pulp/paper, but future economic scenarios may place this resource as Manitoba's largest renewable heating fuel.
8. Biomass heating technologies presently being used are combustion systems designed for densified or loose by-products of agricultural and forestry processes.
9. New commercial and/or residential developments provide an ideal opportunity to integrate biomass fired district heating.
10. The types of locations in Manitoba which may be the best suited for the biomass-to-heat applications are as follows:
    a. Rural businesses or towns located close to sawmill/forestry operations which can access a steady supply of processed biomass (e.g. sawdust) at no to low cost, feed it into a boiler unit and use it in a hot water heating loop.
    b. Hutterite colonies and greenhouses with existing boiler systems providing hot water heat. These facilities can access the existing locally processed biomass fuel sources (e.g. oat hulls, wood chips, flax shives) available to provide a steady, reliable flow of energy.

c. Small towns (including reserves) within 50 km of biomass supply (forestry or agriculture) which have existing hot water boiler systems.
d. Industrial facilities producing biomass, integrating it into their own heat processes. No transportation of biomass would be required.

11. The use of biomass as a heating fuel carries an energy cost, has environmental implications and a lifecycle which need to be fully considered when substituting for fossil fuels.
12. Manitoba's biomass infrastructure includes all the necessary components (suppliers, transporters, densifiers, boiler manufacturers) to continue developing the biomass sector, and is in a good position to grow when either incentives or fossil fuel prices provide the reason to expand.

Lessons from Denmark

As part of this study, special attention was paid to the biomass situation in Denmark, a country using biomass as a key component of its renewable energy strategy. The following is adapted from information prepared by FORCE Technologies of Denmark for this study.

Danish energy policy focuses on a secure energy supply, awareness of the environmental and climate aspects of the use of energy, and cost effectiveness of energy supplies. In order to address its complete dependency on imported oil, the Danish Government has put an emphasis on increased energy efficiency, use of waste heat from power stations and a strong growth in district heating. Other initiatives have led to increased use of renewable energy, including biomass and waste. One result of these policies is that Danish companies and research institutions today are internationally acknowledged for the development of new energy technologies. The Danish export of energy technology has in recent years grown faster than the overall Danish exports and today the energy technology export sector constitutes approximately 10 % of the total Danish exports in 2008.

Currently, renewable energy accounts for 13.8% of Denmark's total energy use. Biomass currently accounts for 70 to 75 % of renewable energy consumption, mostly in the form of straw, wood and renewable wastes and biogas. Consumption of biomass for energy production in Denmark more than quadrupled between 1980 and 2005. Agricultural and forestry biomass accounts for approximately 60 PJ of the total 120 PJ derived from renewable energy resources.

9.3 Recommendations

As a result of this study, DLF Consulting has prepared the following recommendations which Manitoba Hydro may consider:

1. Support feasibility studies to identify appropriate biomass heating applications for commercial operations, small towns, Hutterite colonies, greenhouses, and district heating applications.
2. Encourage use of biomass for heat and consider incentive based programs to assist with the transformation of the market.
3. As Manitoba's primary biomass resource is straw, and given that this resource can be used directly for heat (without densification), provide a demonstration of how this can be done with established leading edge

biomass technologies in Manitoba (e.g. the well proven straw-to-heat technology from Denmark).

4. Develop a neutral information source to provide information on biomass feedstock and technologies options.
5. Develop an energy partnership with a similar sized European district presently utilizing biomass for district energy.
6. Investigate ways to finance greener and more sustainable technologies (e.g. clean technology funds) and explore what other countries are doing with sustainable initiatives to tap into public interest and environmental awareness.

Supportive measures by the Manitoba Government may include:

7. Establish biomass-to-heat as an energy policy priority as it provides one of the few actual ways to decrease importation of non-renewable fuels (e.g. establish biomass fired district heating as a requirement for new developments).
8. Study the impact of crop and forestry residue removal and create guidelines for its sustainable use.
9. Develop grants and tax incentives for those developing biomass recovery and processing businesses (e.g. densification) and thermal conversion equipment.
10. Work with financial institutions to subsidize loans at low interest rates to increase the attractiveness of these investments.
11. Create air emissions policies which balance emissions priorities with GHG emission, permitting more biomass fuel users.

Appendix A: Site Visits and Interviews

1. **Primary Research – Site Visits**

Biomass Resources

- Can-Oats (Viterra) – Portage la Prairie
- Prairie Agricultural Machinery Institute – Portage la Prairie.
- Aboriginal Cogeneration Corporation railroad tie grinding facility – Kamloops, BC.

Biomass Heating Technologies

- Biomass Combustors:
  - Blue Flame Stoker – Sturgeon Creek Hutterite Colony
  - Decker Boiler – Rock Lake Hutterite Colony
  - KMW Boiler – Revelstoke, BC.
  - King Coal – Bismarck, ND.
  - Orverter - Winnipeg
- Gasifiers
  - Downdraft – Energy and Environmental Research Center – Grand Forks, ND.
  - Updraft – Nexterra, Victoria, BC.
- Biomass dual stage combustion system – Biomass BEST, St. Adolf

Biomass Heating Applications

- Biomass heating system, landfill, recycling facilities – Bismarck, ND.
- Pineland Nursery - Hadashville
- Hutterite Colonies:
  - Sturgeon Creek
  - Starlite
  - Clearwater
  - Rock Lake
- Wenkai Greenhouse – Elie
- Blue Lagoon Greenhouse – St. Francis Xavier
- Biomass powered district energy system – Revelstoke, BC.
- Dockside Green: Biomass powered district energy system (gasifier), innovative housing, water reclamation, New Urbanist model – Victoria, BC.

2. **Primary Research – Interviews**

- Manitoba Hydro
- University of Manitoba Mechanical Engineering, Biosystems
- Ouje-Bougoumou District Energy System
- Gem Equities/B&M Land
- MEIA - Manitoba Environmental Industries Association
- Manitoba Government (Forestry, Agriculture)
- City of Winnipeg
- Agriculture Canada
- Natural Resources Canada
- Aboriginal Cogeneration Corporation
- Nexterra
- Prairie Bio Energy
- Westroc Energy
- Briquetting Systems
- Tembec
- Force Technologies (Denmark)

Appendix B: Case Study: Straw fired district heating - Thorsager, Denmark[116]

This case study was prepared for Manitoba Hydro by Anders Evald of FORCE Technologies in Denmark.

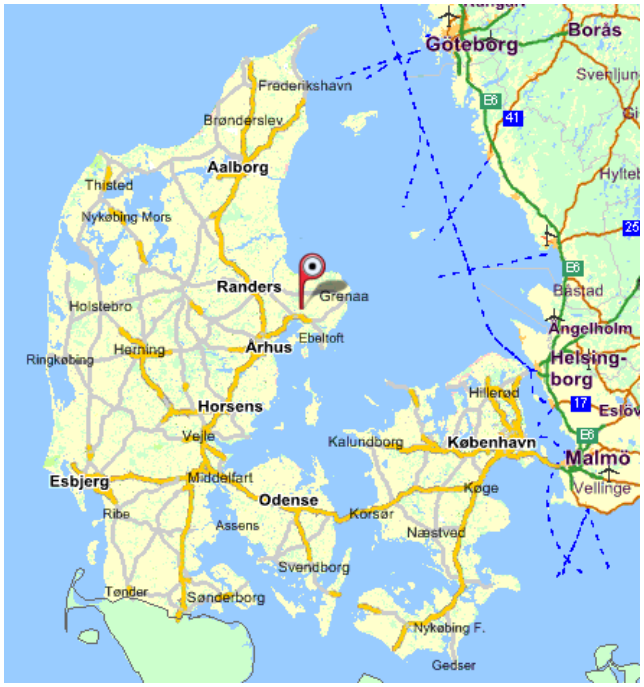
Introduction

For more than 20 years agricultural residues, mainly in the form of straw, have been used for energy generation in Denmark. In farm scale several thousand small scale boilers provide heat for the farm houses, for grain drying etc. In the heating sector straw competes with wood chips, wood pellets and natural gas to supply heat from central boiler installations connected to consumers through district heating networks. And in the larger scale straw is now also being used for power production in combined heat and power plants, either in dedicated straw boilers, or in a mixture with other fuels such as wood or coal.

In the following, we provide a description of one of the straw fired boilers providing heat for district heating systems.

Location

The plant is located in the small town Thorsager near Aarhus in the Eastern part of Jutland in Denmark.



Plant location in Denmark

[116] Anders Evald, Force Technologies, Dec 2009

The climate in Denmark is relatively mild due to the location near the Gulf Stream. Average winter temperature is about 0°C, and summers about 17°C. Due to the need for heating of indoor space for 7-8 months a year and due to relatively high costs for heating based on government taxes on fossil fuels such as heating oil and natural gas for private heating purposes, district heating has developed into a success story in Denmark. Today about 60 % of all homes in the country are hooked up to a district heating network.

The heating plant is located in an area of the town occupied by small commercial businesses and light industry. The nearest neighbouring property is 50 m from the property line of the heating plant.

Application

The heating plant in Thorsager, Denmark is a typical straw fired boiler system for this size range. Heat is supplied into a district heating network, with 384 connected heat consumers that cover most of the town. The boiler plant receives straw from nearby farmers as 500 kg Hesston bales, which are shredded before combustion on a moving grate.

A typical biomass district heating plant in Denmark may have 1000 hookups; the majority would lie between 100 and 10,000 connections.

Plant capacity

The straw boiler has a nominal heat production capacity of 3.15 MW thermal output.

As spare capacity and for peak load heat demand during the coldest periods of winter, an additional oil fired boiler of exactly the same capacity, nominal 3.15 MW thermal output is installed.

A thermal heat storage consisting of a cylindrical water tank can even out load variations on the heat demand side. This way the boiler can be operated under more optimal combustion conditions, and straw fired heat can cover the demand, even when the demand - for shorter periods - exceeds the boiler capacity.

The straw boiler is typical for Danish district heating plants, where the average is about 4 MW thermal output, and where virtually all plant are between 1 and 10 MW.

Fuel type

The main fuel for the district heating plant is agricultural residues in the form of straw from nearby grain producing farms.

Straw is commonly used this way in Denmark, where about 50 district heating plants use straw as a boiler fuel. A total of 236,000 ton of straw is utilized this way; this corresponds to about 22 % of the overall 1.06 million ton of straw used for energy in the country.

Other fuels used in similar plants are wood chips, wood pellets and other wooden residues. A total of 120 district heating plants use solid biomass fuels as the main fuel source.

The straw used in Thorsager could be from any grain production. In practice, about 90 % of the annual consumption is wheat straw; the rest is divided between straw from winter rye, oats and other crops.

Fuel supply system
Straw is supplied by the farmers to the heating plant as Hesston bales, measuring approximately 1.2 x 1.3 x 2.2 meter (h x w x l) and weighing about 500 kg each. More recent bale presses can make more dense bales at up to 750 kg weight with same geometry. The plant can handle such bales; however, none of the farmers supplying straw presently have introduced these newer presses.

Bales are pressed in mobile big bale presses, most often of the brand Hesston, thus the name of the bales. Pressing are done in the field by mobile equipment. Larger farms would own their own press, but most of the smaller ones would contract an agricultural machinery service company to perform the actual baling.

Storage takes place at the individual farm in a straw barn often erected solely for this purpose. Under roof storage is not exactly a requirement in the delivery contract with the district heating plant, but the requirement to supply dry straw with no soil can be met this way, and experiments with cheaper solutions such a open air storage with plastic covers has been abandoned.

The farmers store the straw from harvest in late summer (August) until it is needed at the heating plant (between September and July the following year).

The 50 farmers who supply straw to the heating plant is organized in a straw supply association, which supplies straw to Thorsager as well as the neighboring town of Rønde. Formally the contract for straw supply is between this association and the district heating company.

The 50 farmers take turns in who supplies first to the plant. One year a farmer will supply all his straw in September, next year moving on to October etc.

The majority of the supply takes place on small farm trailers with a tractor; each load would take between 12 and 26 bales. A few farmers transport the bales on trucks.

Straw consumption
The annual consumption of straw is approximately 2,500 ton.

Fuel reception
Bales are unloaded from the trailers by the heating plant personnel using a fork lift truck equipped with special spikes to catch the bales. The truck is equipped with an on board weighing system that weighs each bale; these data are later on used for settling the payment for the delivery.

Moisture is measured in each bale using a portable spear type moisture detector, which is jabbed into each bale in 3 different positions. If the load seems to be acceptable in terms of moisture, a less rigorous scheme for moisture detection is used; and on the other hand when the first measurements gives rise for suspicion, that the load may be too wet, more measurements are taken.

Each bale must be less that 22 % of total weight moisture content, otherwise it is rejected at reception. Rejection is very rare today, where the farmers have learned the necessary lessons on how to achieve acceptable straw moisture through indoor storage etc.

Onsite storage

The plant can store up to 250 bales, which could cover up to about 10 days during winter, where consumption may be up to 26 bales a day. During summer, where daily consumption may be as low as 5 bales a day, the storage can cover more than a month of operation.

The main straw onsite storage (not covered by the crane) with at total capacity of about 250 bales (125 metric ton)

Fuel transport system

The bales are placed under a unirail crane, which is automatically controlled by call for fuel from the boiler. A sensor on the crane reads the position of bales in the line, pick up a bale and lift it to the feeding line, where transport chains move the bale into the string cutter and further into the shredder.

Bales in line (left) for automatic lift by the crane (top) to the feeding table (centre, in red)

The shredder is manufactured by the Danish company Weiss, who also supplied the boiler and most of the auxiliary systems in the plant.

From the shredder, straw fall in a more or less loose form into a feeding bin, from where it is pushed into the feeding canal , a rectangular 0.3 by 1.0 meter confined space, where the straw form an airtight plug between the furnace and the feeding system. The end of the feeding canal leads the straw directly onto the combustion grate.

The feeding system is protected against backfire with two independent thermostatic water sprinkling systems and a fire gate.

Combustion system
Combustion takes place on an inclining step grate, about 1.2 m wide, and 3.5 to 4 m long.

Primary air for combustion on the grate is blown through the grate from the bottom. Secondary air is blown in from the sides of the furnace above the grate, supplying most of the oxygen needed for the gas phase combustion.

A special system for tertiary air has been fitted in this, and other similar boilers installed during the last few years. All combustion products are drawn through a circular nozzle, where additional combustion air is added while the gases are still very hot, and under turbulent mixing conditions. This way this boiler achieves significantly better combustion with less emissions and higher efficiency than earlier generations. This system was developed by Weiss in co-operation with FORCE Technology.

Furnace and boiler section to the right, and bag filter to the left

Boiler section
After the furnace flue gases are lead into the boiler section, which consist of 5 vertical sections of tubes, flues gas in the tubes, boiler water on the outside. Flue gases leave the boiler section at about 120°C.

Ash deposition in furnace and boiler is an important issue when using agricultural residues as a fuel. The boiler sections are equipped with an automatic cleaning system that blows pressurized air into the pipes in brief shots at set intervals. Further, the furnace and boiler sections have several hatches which give access for manual cleaning.

Flue gas cleaning

Dust in flue gas consists of the fuel ashes carried with the flue gasses through the system as well as aerosols created through nucleation from gaseous mineral compounds in the flue gas.

Coarse particles are mostly removed in the inlet part of the bag filter, where the outer layer functions as a cyclone. The finer particles are then removed in the bag filter, also supplied by Weiss, with 291 individual bag elements and a total surface areal of 345 m^2. Compared to earlier systems on straw fired boilers, this more recent bag filter has much less load per m^2, and the expected life time for the bags are more than doubled.

The bag filter has a maximum operating temperature of 125°C; if this value is exceeded, a bypass on the flue gas side is opened automatically.

Ash handling

Bottom ash from the grate falls into a wet ash conveyor system. Fly ash from the bag filter is collected under the filter and transported in a screw conveyor to the bottom ash system, where the two ash fractions are mixed. The mixed ashes go into a container.

According to national legislation in Denmark, ashes from the combustion of uncontaminated agricultural residues are allowed to be distributed back into farmland. The conditions require analysis of ash samples a couple of time pr. year, and that the farm who takes back the ashes integrate the distribution of the nutrients in his planning for fertilizer use in his fields.

The general principle is that distribution of ashes is allowed in an amount per hectare that corresponds to the ash content in the amount of straw originally harvested from the area. The main concern behind the rules are trace elements, first of all Cadmium, in the ashes. These compounds originate from the fields, but are recycled in a concentrated form.

Heat storage

A heat storage tank of 1000 m^3 is used to even out heat load variations. This way the boiler can be operated under more optimal conditions - partial load is avoided as it is never run at less than 50 % capacity. The tank is filled with boiler water at 98°C (the boiler water is warmer than the water circulated in the street pipelines) and has a total capacity to store 68 MWh of heat. During most weekends, the tank is utilized to full capacity, thus it can often be avoided to run the straw boiler at all when no personnel is available at the plant. During summer, the tank can cover the heat demand in the town for up to 5 days. The heat storage has improved the efficiency in the plant significantly.

Other equipment

The stack is 27 meter high with two pipes, one for the straw boiler, and one for the oil boiler. Other equipment includes frequency controlled fans for combustion air and flue gas, a hydraulics system and pressurized air for boiler cleaning

Control and monitoring systems including computers and monitors, and a remote control system, that gives the operator complete control over the plant from his home. The plant is capable of unmanned operation as long as there is fuel in the storage. Alarms go to the operators' mobile phone.

Buildings

The building contains the straw storage, the boiler room, a room for noisy equipment, a control room with electrical and electronic installations, an office with two office work desks, a meeting room (mostly used for board meetings) and a toilets and shower section.

The heating plant with straw storage to the right, boiler building in the center, stack to the left, and the heat storage tank behind

Manning

One operational manager, full time employed, runs virtually all daily operation at the plant: straw reception including weighing and moisture determination, maintenance of boiler and transport equipment, operation and maintenance in the district heating network, reading (remote reading) of heat meters, consumer contact, office work, daily accounting etc. Some of the accounting is performed by an assistant, who comes by a few hours every week. Also during vacation or illness, the manager is substituted by an assistant.

District heating system

The whole system consists of two parallel pipes, one for forwarding the hot water from the central, and one for return water after cooling at the consumers. The forwarding temperature is 75°C all year round, while the return line is about 35°C during winter and 45°C during summer.

The district heating pipeline system consists of 9.2 km double main street pipelines, and 6.0 km connection pipes (double) to the consumers. Most inner pipes are made of steel, preinsulated and with an outer lining of plastic. In smaller dimensions, and for all hookup lines, plastic inner pipes (PEX) are used, also presinsulated.

There are 384 metering points, where the heat consumption in the house is measured. The meters include a radio transmitter and are read remotely by the plant operator 3-4 times a year.

Most consumers are private households. Thorsager does not have much business and industry, and few of these are connected to the system. The largest individual consumer is the school, which takes up about 350 MWh a year, second is the local grocery store at about 40 MWh a year. Most individual homes are detached houses in the 100 to 150 m2 range and would typically take 12-25 MWh. Only a few hookups are attached houses or apartments. Roughly 90 % of the heat demand is used by private homes.

This picture is fairly normal for Danish conditions, where most district heat plants have the majority of hook-ups as private homes, say 9 out of 10. The last 10 % of hook-ups is larger buildings like the town hall, schools, sports complex and other public buildings. Commercial sector (shops, smaller service businesses) often count relatively little, and proper industries are rarely an important part of the heat demand in district heating in Denmark.

Heat losses in the district heating system in Thorsager account to a total of 33 % of the heat produced at the district heating plant. This may seem like a high figure, and other systems in Denmark actually perform better, down to 20 % or even 15 % for the very best. The heat losses are very dependent on the how close the heat consumers are to each other and how big the consumption is in each hookup. In this context Thorsager is a widespread town with long pipeline length as compared to heat sales.

A continuous effort is ongoing to lower the losses. Return water temperature is lowered by installing more heating surface (radiators) in the homes that have too high return water temperature. Pipelines are replaced with new ones with better insulation. Temperatures in the system are monitored at all times, and lowered whenever possible. Leaks are investigated and repaired. Correct metering is tested.

Ownership and economic strategy

The district heating plant and the district heating pipeline system is owned and operated by a private entity owned by the heat consumers. The legal organization is co-operative society, but the liability of the individual consumers is limited.

The municipality guarantees for loans taken by the company.

The company is lead by an annual general assembly, where the board is elected. The 6 person board is then responsible for employment of the plant manager and any assistance required, for the annual accounting, for budget and tariffs, and for the strategic development including investments in new equipment.

The purpose of the company is to supply heat to connected consumers in Thorsager on a non-profit basis. The company will need to seek optimized solutions for the production and distribution of heat, which is the background for choosing straw as a fuel. Danish

legislation protects consumers connected to a monopoly supply system, and the company is simply not allowed to make a profit.

Tariffs for connection fees and heat costs are settled annually based on a budget for the costs for straw, financial costs, manning costs etc. at the plant for the following year.

Heat tariff
Initially the company settled the tariff solely on the consumption of heat. This lead to high variable cost for the consumers, so some continued heating with wood. At the same time the plant was very sensitive to seasonal variations in climate: in a warm heating season there was simply insufficient income to pay the fixed costs for finance, manning etc. at the plant.

Today the tariff consists more or less equally of a variable element dependent on the metered heat consumption, and a fixed element which is independent of consumption. A few has complained, but generally, consumers accept the necessity of this tariff structure, and are satisfied as long as the total heating bill is lower than comparable heating by oil (which is always the case).

Investment
The first straw plant was installed in Thorsager in 1989. At that time, the investment was 20 million DKK (4.3 million CAD; exchange rate: 1 DKK = 0.21 CAD, November 2009), which included the straw fired boiler plant including storage, buildings etc. and the complete district heating system. Government support was grated for the first investment back then in the order of 15 % of the investment.

When the new plant was installed in 2007, the total investment in boilers, new building, new storage and the heat storage tank - but exclusive of the district heating system - was 15 million DKK (3.2 million CAD). There were no subsidies given for the new plant, however the loans were again guaranteed by the municipality at favourable conditions.

Straw price
The present straw price is 550 DKK (117 CAD) pr. metric ton, recently up from 420 DKK (90 CAD), a level maintained almost constant for 20 years.

The straw price is the same independent of moisture content between 14 and 17.9 %. Outside these limits a compensation or deduction is made for drier or more moist straw.

The price actually paid to the farmer varies over the season. The basic price above applies in January. For earlier deliveries the price is slightly lower, and for later deliveries slightly higher. This is to compensate the farmer for his costs with straw storage.

Economic performance
An indirect subsidy element exist in the high energy taxes and carbon-dioxide taxes on fossil fuels (heating oil and natural gas) for heating in private homes in Denmark. As the alternative costs are artificially high, the consumers are prepared to pay a relatively high price for heat supply from the straw fired district heating plant.

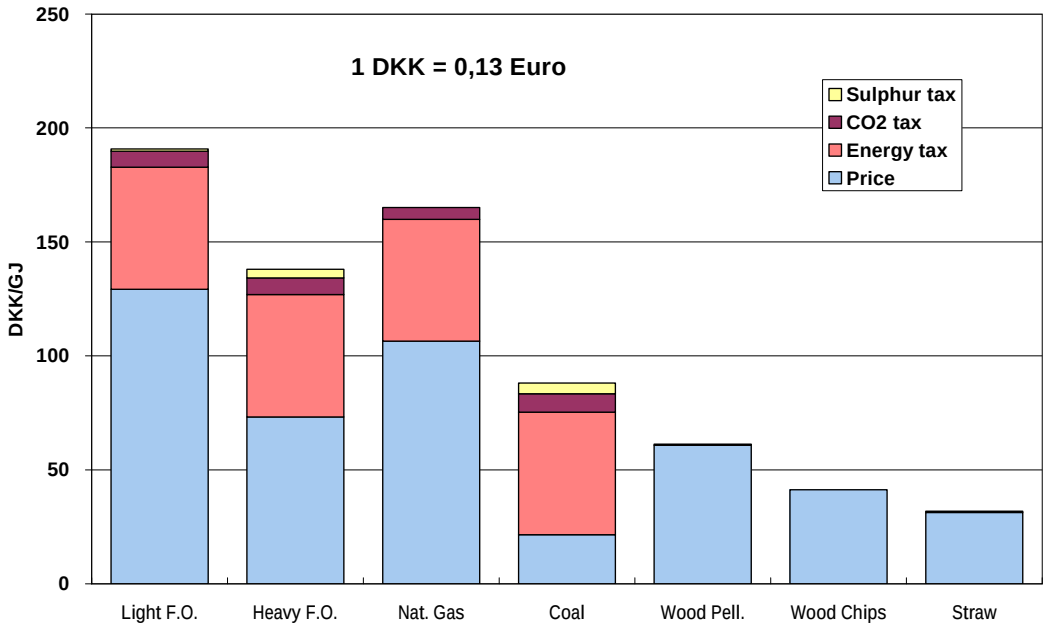


Illustration of costs for fuels in Denmark, including the heavy energy and carbon dioxide taxes on natural gas, fuel oil and coal. There are no such taxes on solid biomass fuels.

A rough annual operational budget is:

Straw procurement	1.25 mio. DKK	0.27 mio. CAD
Manning	0.50 mio. DKK	0.11 mio. CAD
Operation and maintenance	0.25 mio. DKK	0.05 mio. CAD
Power, water and chemicals	0.16 mio. DKK	0.03 mio. CAD
Administration	0.26 mio. DKK	0.06 mio. CAD
Interest payment on loans	0.58 mio. DKK	0.12 mio. CAD
Depreciation on investments	2.10 mio. DKK	0.45 mio. CAD
Total	5.10 mio. DKK	1.09 mio. CAD

Income from heat sales and fixed tariff elements balance the annual costs.

As a consequence of the non-profit principle set out in legislation for heat supply, the plant is in principle not allowed to make a profit. In practice some years may provide a small margin which is then paid back to consumers through reduced tariff the following year.

Environmental performance

According to the environmental approval, the stack emission of dust is not allowed to exceed 40 mg pr. normal m^3 at 10 % reference oxygen level in flue gas.

Regular measurement during the past few years document this limiting value met at all times.

The plant does not have other limitations on emissions such as CO or NO_x. This is due to the relatively small size of the plant; for plants above 5 MW such limits normally apply.

The environmental approval for the plant includes a limit for noise, 40 dB at property border line during night time. During the engineering phase it was decided to put fans and compressors in a separate sound insulated room within the plant. There are no problems, neither with reaching the set limit, nor with complaints from neighbours.

Anders Evald
FORCE Technology, Kgs. Lyngby, Denmark
November 2009

Appendix C: Information Sources

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3. ASTM: www.astm.org
4. Biomass Energy Resource Center (BERC): http://www.biomasscenter.org
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7. Boilersmith Boiler: http://www.boilersmith.com
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13. Decker Manufacturing: http://www.deckerbrand.com
14. District Energy St. Paul: http://www.districtenergy.com
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16. ECL Phyllis database: http://www.ecn.nl/phyllis/DataTable.asp
17. Force Technologies - Anders Evald, Denmark
18. Fuels for Schools and Beyond: http://www.fuelsforschools.info
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MANITOBA HYDRO MONITORING STUDY

Performance of Ground Source Heat Pumps in Manitoba

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1.0 Executive Summary:

Manufacturers of geothermal heat pumps have traditionally reported coefficients of performance (COP) of 3.1-to-4.0 and energy efficiency ratio (EER) of 14-to-24. These efficiency levels are based on instantaneous tests conducted under controlled conditions and do not consider all of the losses that may occur in an installed system operating in varying conditions.

This study monitored ten homes over an extended period during all heating, cooling and shoulder months to determine the average Seasonal Coefficient of Performance (SCOP) and Seasonal Energy Efficiency Ratio (SEER) of typical heat pump systems operating in an "as-installed" environment.

Test data for ten Manitoba homes shows that the SCOP of the monitored ground source heat pump systems range from 1.8 to 3.5 with an average of 2.8 for a one year period. SCOP is defined as the total energy (kWh) delivered by the system divided by the total electric energy input (kWh) to the system over one heating season. The average annual electric energy saved was 15,842 kWh when compared to conventional electric resistance heat. The systems operated for an average of 2041 equivalent full load hours in heating mode.

The average SEER of the ten monitored homes during the cooling season was 13.3. The estimated average annual energy saved was 17 kWh compared to a split central air conditioning system with a SEER of 13. The cooling savings with a ground source heat pump were minimal but this may not be a fair comparison since the SEER 13 assumed for the central air conditioner is based on controlled test conditions and is not based on actual monitored field data. The systems operated for an average of 218 equivalent full load hours in the cooling mode.

The desuperheater option reduced the average domestic hot water electric energy usage by 610 kWh (18%). It was found that 86% of the savings were produced during the heating season. Therefore, the heat pump had to operate longer to transfer this additional energy requirement. This additional energy requirement during the heating season only increased seasonal imbalance on the ground. Most of the systems operated with storage water tank temperatures lower than the 60 ^{o}Celsius (140 ^{o} Fahrenheit) that is the minimum temperature setting requirement of the National Plumbing Code for electric storage water heaters. One of the desuperheater pumps was replaced prior to the study period due to motor failure. Another pump failed during the study period. Considering all of these factors, the desuperheater option does not appear to provide the same benefit in a heating dominated climate as it would in a cooling dominated climate.

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2.0 Background:

Manitoba Hydro has been promoting geothermal heat pump systems through the Residential Earth Power Program since April of 2002. Since program launch, over 950 customers have applied for the Residential Earth Power Loan. Manitoba Hydro has worked with industry and other partners to determine the actual geothermal system performance over an entire heating and cooling season. The performance levels reported by various manufacturers are based on an instantaneous test and do not consider all of the losses that occur in an actual system. The performance values reported in this study reflect measured performance values monitored at "as-installed" working systems.

In two previous case studies in Manitoba, where actual field performance was measured it was found that the seasonal coefficient of performance (SCOP) over an entire heating season for five homes ranged from 1.4 to 2.9. The case study that included four homes indicated that two of the homes produced SCOP's of 1.4 and 1.6 but lack of maintenance and improper use of the system was found to be the cause of their poor performance. The other two homes in that study had no operational issues and produced SCOP's of 2.5 and 2.8. The second previous case study was of a single home, measured a SCOP of 2.9 for one heating season, and an SCOP of only 2.2 in a subsequent heating season. The reduction in performance in the second year was caused by a control failure which caused the auxiliary heat to operate excessively.

Based on the two previous case studies and analysis of heat pump customer billing data, Manitoba Hydro uses an average ground source heat pump SCOP of 2.5 and an EER of 14 for calculating the energy savings claimed by our Earth Power program. Manitoba Hydro wanted to study more residential ground source heat pump installations to provide a larger and more varied sample. A larger sample was expected to more accurately represent heat pump SCOP's of reasonably installed systems and therefore ensure that the energy savings claimed by the program would be fair and realistic.

It was felt that more extensive research needed to be completed to clarify the circumstances under which a desuperheater is beneficial in a heating dominated climate such as Manitoba. This is important because the high cost of a desuperheater increases the initial cost of the system and the high cost barrier of geothermal systems has been identified as one of three main barriers to widespread adoption of the technology. Removing the desuperheater from this initial cost may reduce the simple payback period. Conversely, when circumstances make the desuperheater a worthwhile investment, the payback period on the overall system may actually be reduced. Actual desuperheater field performance needed to be measured.

Since Manitoba is a heating dominated climate there are concerns regarding the long term thermal performance of the ground loop. This study will measure the annual energy imbalance that is placed on the ground loop due to heating, cooling, and hot water (desuperheater). The annual energy imbalance is calculated by subtracting the quantity of heat rejected to the ground from the quantity of heat removed from the ground loop in a one year period.

3.0 Study Objectives:

The objectives of the study were to determine:

1. an average annual Seasonal Coefficient of Performance (SCOP for the heating season), and an average Seasonal Energy Efficiency Ratio (SEER for the cooling season),
2. the average annual water heating electric energy reduction due to the desuperheater, and
3. the average annual heating savings provided by a reasonably well installed ground source heat pump system in Manitoba.

The ten homes monitored are a biased sample since most of the homes were volunteered for the project by experienced and established heat pump contractors and /or distributors that were contacted and nine of the systems were relatively new (less than three years old). The one older system in the study was the only open loop (well to well system) in the study. This system was re-commissioned when it was discovered at the preliminary site visit that it was performing poorly (COP of 1.5) due to water supply issues.

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4.0 Test Method:

Monitoring of these systems was achieved by sub-metering the ground loop energy (extraction and rejection), the electrical energy provided to all the electrical components connected to the heat pump unit, the energy provided by the desuperheater (DSH), and the electrical energy provided to the domestic hot water heater for ten homes located throughout Manitoba for an entire heating and cooling season.

4.1 Seasonal Coefficient of Performance (SCOP*)

The SCOP* of each unit was determined by summing the heat energy provided to the home by the ground loop with the heat energy provided to the home by the electrical components of the heat pump then dividing the sum by the electrical energy required to operate the heat pump for an entire heating season.

SCOP Calculation:

$$\mathbf{SCOP = \frac{kWh_{GL} + kWh_{EL1}}{kWh_{EL2}}}$$

Where: $\mathbf{kWh_{GL}}$ = Ground Loop kWh Output
$\mathbf{kWh_{EL1}}$ = compressor, fan, DSH pump, aux. heater kWh usage
$\mathbf{kWh_{EL2}}$ = compressor, fan, DSH pump, aux. heater and ground loop pump kWh usage

4.2 Seasonal Energy Efficiency Ratio (SEER*)

The SEER* of each unit was determined by adding the heat energy (BTU) rejected to the ground loop and the desuperheater during the cooling season, subtracting the heat energy (BTU) provided to the ground loop and desuperheater loop by the electrical components then dividing this total by the electrical energy required to operate the heat pump for an entire cooling season.

SEER Calculation:

$$\mathbf{SEER = \frac{(BTU_{GL} + BTU_{DSH}) - (BTU_{EL})}{Wh_{EL}}}$$

Where: $\mathbf{BTU_{GL}}$ = heat rejected to ground loop
$\mathbf{BTU_{DSH}}$ = heat rejected to desuperheater
$\mathbf{BTU_{EL}}$ = Compressor, Fan, and desuperheater pump electrical usage (kWh) converted to BTU

***The ground loop pump electrical energy consumption was not included in the electrical heat energy since it was already accounted for in the ground loop heat energy measurements.**

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4.3 Desuperheater (DSH) Energy Savings

DSH Energy Savings (kWh) = kWh_{DSH} - kWh_{ELDSH}(heating Mode or Cooling Mode)

Where: kWh_{DSH} = DSH Output (kWh)

kWh_{ELDSH} = electrical energy into desuperheater energy output

kWh_{ELDSH} (Heating Mode) =DSH Output(kWh)/COP

kWh_{ELDSH} (Cooling Mode) = DSH pump energy(kWh)

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5.0 Heat Pump System Monitoring Method:

To determine the SCOP and SEER of each heat pump system, the following values were required to be measured and applied to the SCOP and SEER Calculations:

1. Total kWh electrical energy input into the system
2. Total BTU Output from the ground loop heat exchanger.

Refer to Appendix C for a listing of measurement and monitoring devices and specifications.

5.1 Total Electrical Energy (kWh) Input into the System:

The following electrical loads were monitored to determine total kWh energy consumed by the heat pump system:

1. Compressor (Stage 1 and 2 if applicable)
2. Auxiliary Heat
3. Ground Loop Pump (1 or 2 pumps, Stage 1 and 2 as applicable)
4. Fan Motor (heating and cooling mode)
5. Desuperheater pump

Split-core current transducers (CT's) were placed on the conductor supplying each electrical component so that each component's consumption could be measured and monitored separately. One potential transducer (PT) was connected to the main electrical service panel to reference the line-to-line voltage supply to the heat pump system. This allowed the data logger to monitor correct Power Factor and kWh measurements of each component.

The CT's and PT's selected for this project have a manufacturer stated accuracy value of ± 1.0% of measured value.

Refer to Appendix C for detailed CT and PT specifications.

5.2 Total Energy (BTU) to and from the ground loop heat exchanger:

$$Q = m \cdot c_p \cdot \Delta T$$

Where: Q = heat energy transferred [BTU]
m = mass [pounds]
c_p = heat capacity [BTU/pound·°F]
ΔT = temperature difference

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To determine the BTU output of the heat pump system, the temperature differential ΔT between the ground loop-in and out had to be measured as well as the total fluid mass through the heat exchanger. The following values and test points were monitored to determine total BTU energy produced through the heat exchanger:

1. Ground loop temperature Fahrenheit (°F) out
2. Ground loop temperature (°F) in
3. Temperature differential at heat exchanger ($\Delta T = °F_{in} - °F_{out}$)
4. Ground loop fluid flow rate (USGPM)
5. Ground loop fluid flow duration (minutes)

BTU values were converted to kWh by dividing by 3.413

5.2.1 Ground loop temperature measurements:

Ground loop temperatures were monitored using Type 385, 1000 Ohm platinum Resistance Temperature Detectors (RTD) installed directly in the fluid flow using compression fittings mounted to the ground loop piping before and after the heat exchanger coil. To minimize ambient effects on the RTD measurements, efforts were made to ensure, wherever possible, each RTD test point was of equal distance and positioning relative to each other and the heat exchanger input-output locations. To further minimize ambient effects, the data logger analog temperature channels were "locked" to the compressor current sensor channel so that ground loop temperatures were monitored and logged only when the compressor was running in heating/cooling modes of operation.

RTD's selected for this project were Class B accuracy giving an uncertainty of ± 1.5% at 32 °F (0°C) with a repeatability of better than 0.8% (-100°C to 100°C). Each individual RTD certainty produces an overall ΔT calculation uncertainty of ± 3.0% of measured value. Refer to Appendix C for detailed RTD specifications.

5.2.2 Ground loop fluid flow measurements:

To measure the ground loop fluid flow rate, an in-line flow meter was installed between the ground loop pump(s) and the heat exchanger. Measurement readings of each meter were recorded at the time of installation and verified periodically while conducting insitu testing at each installation within the test and monitoring period.

The flow meters selected were Dwyer Series type UV with an accuracy specification of ±2% @ 70 °F ± 2°F and 14.7 PSI with a repeatability of ± 1% Full Scale @ 70 °F ± 2°F and 14.7 PSI. (the ground loop fluid temperature span was measured at 30°F - 65°F at a static pressure of 14 PSI).
Refer to Appendix C for detailed flow meter specifications.

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5.2.3 Ground loop fluid specific gravity verification:

With the exception of one open-loop heat pump system (well to well); nine closed-loop systems contained a standard 25% Methanol-to-water mixture. The specific gravity of the mixture determines the specific heat value which affects the kWh and BTU output calculations for each heat pump. To verify that the recommended 25% Methanol mixture was being used, ground loop fluid from a sampling of three heat pump installations were tested by the Manitoba Hydro Chemical Laboratory to verify their specific gravities. The test results were as follows:

Installation 1: SG = 0.9649 (24% Methanol)
Installation 2: SG = 0.9678 (25% Methanol)
Installation 3: SG = 0.9678 (25% Methanol)

An averaged specific gravity value of 0.97 was used for all pertinent calculations leading to the determination of SCOP and SEER values.

5.2.4 Ground loop flow meter correction factor:

The flow meter selected to measure the ground loop flow rate was calibrated for 100% water as a medium. A correction factor was therefore applied to determine the correct flow rate using a 25% Methanol mixture with an average specific gravity of 0.97.

Based on the flow meter manufacturer's correction formula, a correction factor of 1.02 was applied to all flow rate calculations. Refer to Appendix D for detailed information.

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6.0 Desuperheater Monitoring Method

The energy provided to domestic hot water by the desuperheater (DSH) was calculated by the following equation:

Desuperheater contribution (kWh) = Total Domestic Hot Water Energy (kWh) minus Electrical energy consumed by the water heater (kWh)

Total Domestic Hot Water Energy (kWh) = Energy supplied to domestic hot water usage plus stand-by loss energy of the domestic hot water system.

Energy supplied to domestic hot water usage (flowing water) = $m \cdot c_p \cdot \Delta T$

Stand-by loss energy was calculated by subtracting the electrical energy supplied to the water heater when the desuperheater did not operate for an extended period (e.g. shoulder month) of time from the energy supplied to domestic hot water usage.

The following test points were measured to calculate the energy to domestic hot water usage.

1. water heater cold water temperature Fahrenheit (°F) in
2. water heater hot water temperature (°F) out
3. domestic hot water usage (litres)
4. kWh electrical energy consumed by the hot water tank

To ensure that the temperature measurements were recorded only when hot water was being used, two measures were taken:

1. A time delay relay was connected to the water meter pulse output so that whenever the pulse output contacts closed; indicating water flow through the hot water tank, the time delay relay would operate, thereby closing a set of normally open contacts. These contacts would remain closed as long as the water meter produced pulses. These contacts were connected to the data logger's digital input channel which recorded the total time that the contacts remained closed (run-time of the hot water tank).

2. Secondly, the temperature input channels were locked to the logger's digital input (run-time) channel so that temperature measurements were recorded only when there was water flowing through the hot water tank

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7.0 Verification of Measurements & Accuracies:

Refer to Appendix D for a listing of all test instruments and reference standards used for the accuracy verification and insitu testing described in Sections 7.1 and 7.2 below.

7.1 Monitoring equipment accuracy and precision verification:

Individual data acquisition components integral to each complete monitoring system were sample tested to verify manufacturer stated accuracy and precision and to test for any possible defects.

7.1.1 Current Transducers (CT's):

Out of a total inventory of 116 CT's, random sample groups from each CT rating were tested for accuracy. The sample groups consisted of:

1. Ten 10 amp CT's,
2. Ten 30 amp CT's,
3. Eight 50 amp CT's, and
4. Eight 100 amp CT's.

Each sample group was tested at a minimum of six test points throughout their range. Each CT was connected to the current input channels of an ENERNET K20 logger.

The instantaneous current measurements from each logger channel were then compared to the current values measured by an NRC certified reference standard.

Each of the four sample groups produced average accuracies of better than 0.42% with standard deviations of less than ±0.74%.

7.1.2 Potential Transducers (PT's):

Out of a total inventory of 14 PT's, a random sample of 2 PT's was tested for accuracy.

Each PT was tested at a minimum of six test points throughout their range. Each PT was connected to the potential input channels 1 and 2 of an ENERNET K20 logger The instantaneous potential measurements from each logger channel were then compared to the potential values measured by an NRC certified reference standard.

Each of the PT's produced average accuracies of better than -0.19% with a standard deviation of less than ±0.12%.

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7.1.3 RTD Temperature sensors:

Out of a total inventory of 79 RTD's, a random sample of 10 units were tested for accuracy and precision.

Each RTD was connected to the analog input channels of an ENERNET K20 logger. Testing was conducted at two test points, 25°F and 90°F, which were selected to include the typical range of temperatures expected from seasonal ground loop operation (30°F to 65°F). The RTD's were placed into a temperature bath and the measurements recorded by the data logger channels were compared to a Measurement Canada certified (NRC traceable) digital thermometer.

An average accuracy for the RTD's, was measured at the logger analog inputs, and was tested to be within ±0.67 °F (1.2 °C) of the measured reading throughout the 25°F to 90°F (-4 °C to 32°C range.

An average precision value of ±0.74°F (1.3 °C) was measured between the RTD's. This means that there is a maximum average uncertainty of ±0.74°F (1.3 °C) when calculating ΔT differential between the input and output of the ground loop and desuperheater heat exchangers.

7.1.4 Enernet K20 Data Logger:

Each of the logger's eight analog input channels was verified for precision using RTD simulators of various known resistances.

7.1.5 Ground loop and desuperheater flow meters:

Due to the simplicity of construction, lack of test equipment and reference standard, these devices were not tested. Refer to the manufacturer published accuracy and repeatability specifications in Appendix C.

7.2 Installation and post-installation verification (IN SITU) testing:

A verification test was conducted when the monitoring system was initially installed. The purpose of the verification test was to confirm the following variables:

1. Correct data logger programming and referencing,
2. Correct CT and PT referencing, connection and sizing,
3. Confirm accurate measurement of volts, amps, watts and power factor by the data logger,
4. Confirm accurate measurement and logging of the ground loop and desuperheater input/output temperature differentials,
5. Compare flow meter readings to manufacturer ratings of the ground loop pump(s) and desuperheater pump,
6. Correct operation and logging of the water meter, time delay relay and compressor relay contact closures.

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After a number of weeks (or months) of normal operation, a follow-up In Situ test was conducted to confirm the variables listed above as well as the Potential Transformers and to verify any changes or defects in the monitoring equipment.

8.0 Test Site Selection:

The intent of the site selection was to monitor various heat pump makes, models and loop configurations, in different geographic locations within Manitoba. It was also intended to monitor only heat pump systems that were designed and installed by established and experienced contractors. All units were equipped with the desuperheater option.

The breakdown is as follows:

1. Locations: One test site in northern Manitoba
   One test site in central Manitoba
   Eight test sites in southern Manitoba (mix of urban and rural)

   See Map in Appendix B

2. Manufacturers: Six different heat pump brands were monitored

3. Heat Pump Types: Five single stage units
   Five dual stage units
   Nine water to air units
   One water to air and water (combination) unit
   Six heat pumps were equipped with a brushless permanent magnet DC type fan motor
   Four heat pumps were equipped with permanent split capacitor fan motors (PSC motors)

4. Loop Types: Three closed horizontal slinky loops
   One closed horizontal two pipe loops
   Four closed vertical loops
   One well to well system (open loop)
   One lake loop (closed)

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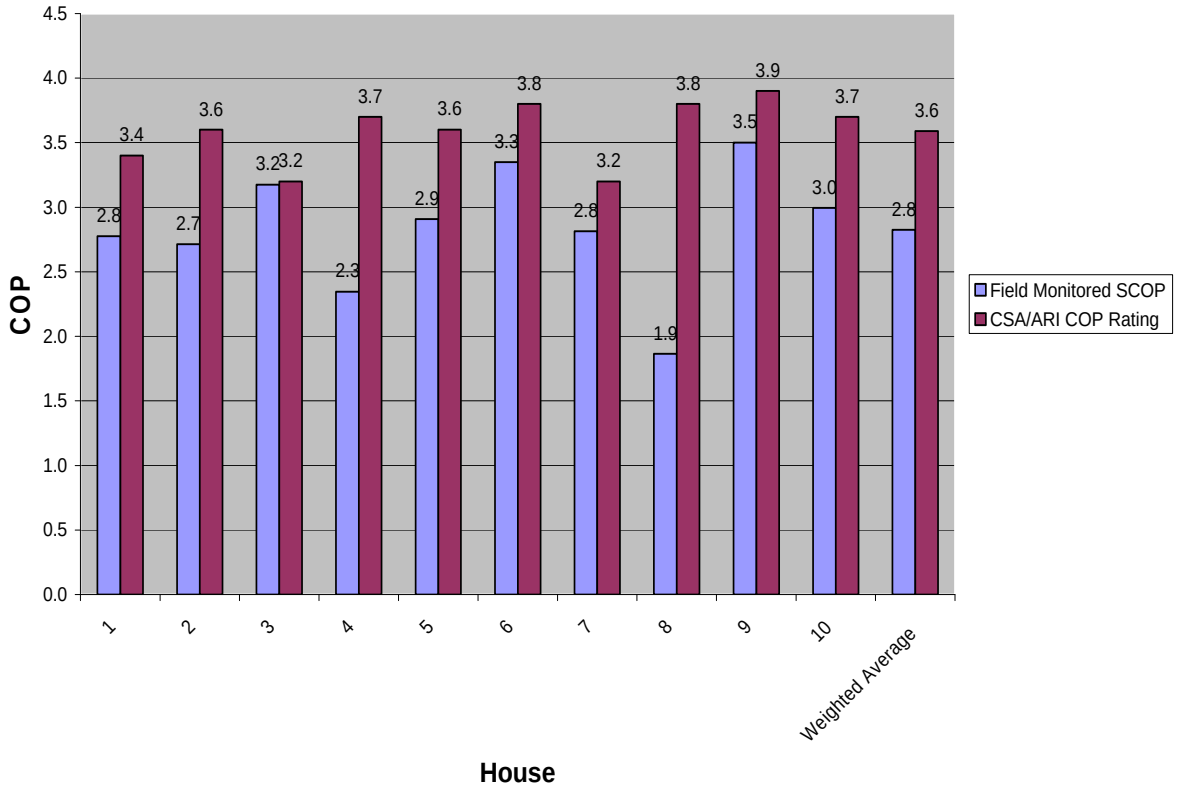
9.0 Heating Season Performance

9.1 Energy Efficiency

The manufacturers ARI tested COP's ranged from 3.2 to 3.9 with an average COP of 3.6. The field monitored test data showed that the seasonal coefficient of performance (SCOP) during the heating season of the monitored ground source heat pump systems ranged from 1.9 to 3.5 with an average of 2.8 over a one year period (see Chart #1 below). SCOP is defined as the total energy (heat) delivered by the system divided by the total energy input to the system over one heating season.

The actual annual energy savings compared to an electric resistance heating system ranged from 3,934 to 29,657 kWh with an average of 15,842 kWh.

Chart #1: Field Monitored SCOP Versus Manufacturer's CSA/ARI COP



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The actual seasonal performance of a ground source heat pump was expected to be lower than the manufacturer stated COP (COP based on CAN/CSA 13256 Test Standard "Water-source heat pumps-Testing and rating for performance").
This is because the test standard does not account for:

1. the energy consumed by an auxiliary heater that may be required
2. shortcomings in the actual system field installation and design
3. fluid pumping power required to overcome the external resistance of the ground loop heat exchanger piping. The standard includes for only internal resistance of the unit itself.
4. the fan motor power required to overcome the external resistance of the connected ductwork. The standard only includes for the internal resistance of unit itself.
5. any start-up and shut down cycling losses
6. variations in entering water temperatures
7. equipment malfunctions
8. variable homeowner operation and lifestyle
9. any lack of system maintenance (air filters etc.)
10. improper system commissioning.

The ground loop pumps delivered an average of 0.75 LPS (11.9 USGPM) and had an average electrical draw of 695 watts. The CSA test standard allows for a default pumping power of 115 watts moving 11.9 USGPM of fluid. Therefore, the average electrical draw for ground loop pumps in the field was 580 watts higher than the amount allowed for in the CSA test standard.

The fan power allowance determined by the formula in the CSA 13256 test standard was 256 watts. This formula is intended to estimate only the fan power required to overcome the internal resistance of the average heat pump unit. In this study, the actual average fan power draw monitored was 592 watts. Therefore, the average electrical draw for fan motors in the field was 336 watts higher than the amount allowed for in the CSA test standard.

The average electrical consumption of the auxiliary heaters was 190 kWh which was less than 1% of the average annual heating energy provided to the homes by the heat pump systems.

The closed loop systems operated with average annual entering water temperature of 36.0^{o}F (4.2 ^{o}C) which is slightly greater than the 32 ^{o}F (0 ^{o}C) temperature that is required by the CSA/ARI test. This should have resulted in slightly improved field performance figures for closed loop systems. Conversely the well to well system operated at an average annual entering water temperature of 44.9 ^{o}F (7.2 ^{o}C) which is slightly lower than the 50 ^{o}F (10 ^{o}C) temperature that is required by the CSA/ARI test. This should have resulted in slightly decreased field performance figures for the well to well system..

Homeowner operation did not appear to significantly affect the system efficiency during the study period for any of the homes.

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It is, possible to calculate an estimated SCOP once the following parameters are known:

- average entering fluid temperature
- additional fan power in watts ($fan_{additional}$)
- additional pump power in watts ($pump_{additional}$)
- estimated annual heating energy requirement ($AHER_{kWh}$)
- estimated annual heating energy requirement provided by the auxiliary heating (Aux_{kWh})

The estimated SCOP calculation example below is based on the overall average system in the monitoring study and assumes the actual average entering fluid temperature (heating mode) is nominally the same as the CSA/ARI test requirement.

Average Heat Pump Unit performance (based on CSA/ARI test):

$Output_{test}$: 11,758 watts
$Input_{test}$: 3275 watts
COP_{test}: 3.59

$$\text{Field installed instantaneous COP } (COP_{field}) = \frac{Output_{test} + fan_{additional} + pump_{additional}}{Input_{test} + fan_{additional} + pump_{additional}}$$

$$COP_{field} = \frac{11{,}758 \text{ watts} + 336 \text{ watts} + 580 \text{ watts}}{3{,}275 \text{ watts} + 336 \text{ watts} + 580 \text{ watts}}$$

$COP_{field} = 3.02$

$$\text{Estimated SCOP} = \frac{AHER_{kWh}}{(AHER_{kWh} / COP_{field}) + Aux_{kWh}}$$

$$\text{Estimated SCOP} = \frac{24{,}523 \text{ kWh}}{(24{,}523 \text{ kWh}/3.02) + 190 \text{ kWh}}$$

$$\text{Estimated SCOP} = \frac{24{,}523 \text{ kWh}}{8{,}310 \text{ kWh}}$$

Estimated SCOP = 2.95

The estimated SCOP of 2.95 is greater than the annual average SCOP of 2.82 obtained from the actual monitoring of the 10 homes in the study. It is assumed that the difference is caused by items that are not accounted for in the estimation calculation such as cycling losses, actual equipment performance, and equipment maintenance.

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9.2 Cost Savings

The heat pump systems provided 6,855 to 42,277 kWh of heating energy to the homes. The average quantity of heating energy provided to the 10 homes was 24,523 kWh.

Average annual electricity savings of 15,842 kWh during the heating season equates to $998 (based on April 1, 2009 PUB approved Manitoba Hydro Residential Electricity Rates) when compared to electric resistance heat.

This annual savings amount would be reduced to $578 when compared to a high efficiency natural gas furnace (natural gas prices based on May 1, 2009 PUB approved Manitoba Hydro Residential Natural Gas Rates and includes the Basic Monthly Charge of $13/month).

9.3 Auxiliary Heat

The ground source heat pump systems provided 97 to 100% (average of 99%) of the total heating energy required by the homes. The remainder was provided by electric resistance auxiliary (back-up) heaters. The auxiliary heaters in the monitored homes used 0 to 929 kWh of electricity. The average electrical consumption was 190 kWh for auxiliary heat.

It appears that all of the heat pump systems were sized to meet the total heating energy requirements for the monitored houses. Since all of the closed loop systems were relatively new, the study does not have enough data to determine what percentage of the annual heating energy requirements the heat pump systems will provide in the long term (10 to 20 years from now). More detailed long term monitoring would be required to determine the sustainability of this performance.

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9.4 Entering Fluid Temperatures

The weighted average annual entering fluid temperature for the nine closed loop systems ranged from 32.8 °F to 39.5 °F (0.4 °C to 4.2 °C) with a weighted average of 36.0°F (4.2 °C) see Chart #2 below. This is just slightly greater than the 32 °F (0 °C) temperature that is required by the CSA/ARI test for closed loop heat pumps.

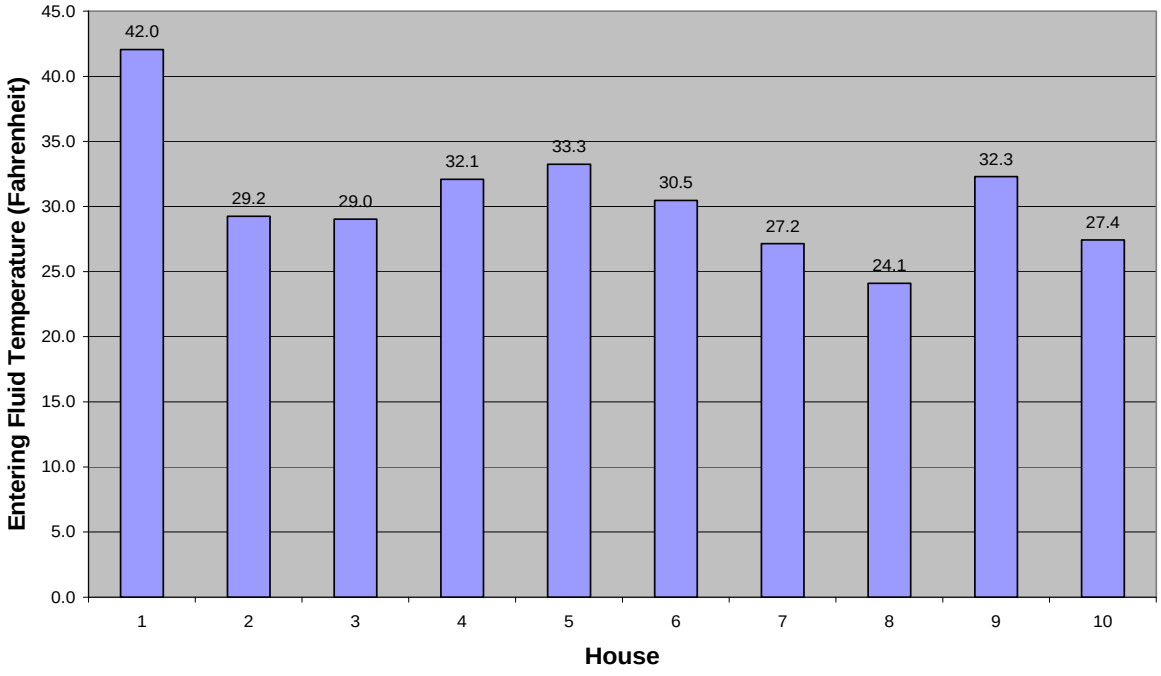
The well to well system had a weighted average annual entering water temperature of 44.9 °F (7.2 °C) which is slightly lower than the 50 °F (10 °C) entering water temperature which is the test temperature requires by the CSA/ARI test for open loop systems.

From information provided by several heat pump designers, most systems in Manitoba are designed with minimum entering water temperatures of 25 °F to 30 °F. (-4 °C to -1 °C) The actual minimum entering water temperature ranged from 24.1 °F to 33.3 °F (-4.4 °C to 0.7 °C) for the closed loop systems and 44.2 °F (6.6 °C) for the well to well system (See Chart #3).

The horizontal loops provided the highest entering water temperatures.

All of the vertical loops were drilled in overburden ranging from 50 to 200 feet deep.

Chart #3: Minimum Entering Fluid Temperature (Heating Mode)



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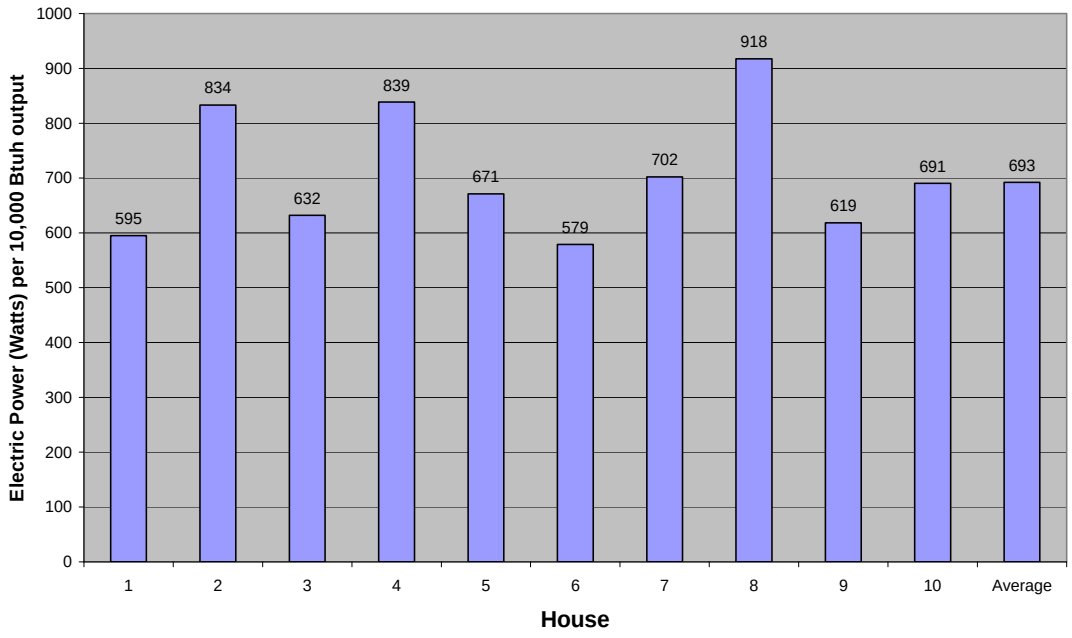
9.5 Compressor

There were five two stage and five single stage compressor systems monitored in the study. The electrical power draw required to drive the compressors ranged from 579 watts to 918 watts per 10,000 BTUh of heat pump output with an average of 690 watts per 10,000 BTUh (See Chart #4 below).

The two compressors with the highest electrical power draw per 10,000 BTUh of heat pump energy output are of the same make and model (839 and 918 watts per 10,000 BTUh of heat pump output). There were three compressors of this model in the study. The third had the lowest energy input when compared to heat pump output (579 watts per 10,000 BTUh of heat delivered). These three compressors are reciprocating compressors that reverse their direction of rotation before mechanically engaging the second stage.

During the monitoring period these three compressors would periodically get stuck in stage one operation even though the system was electrically calling for second stage operation. The COP of the systems was lower during these events since the fan speed was increased to meet second stage heating. If the system could not meet the home's heating requirements when the compressor was still operating in first stage, the auxiliary heater would come on to meet the heating requirements. This would lower the COP even more. According to the equipment supplier, these compressors have had a high failure rate and they are currently being replaced on warranty with an improved type of compressor.

Chart #4: Compressor Electrical Power Draw per 10,000 btuh of Heat Pump Output (Heating Mode)



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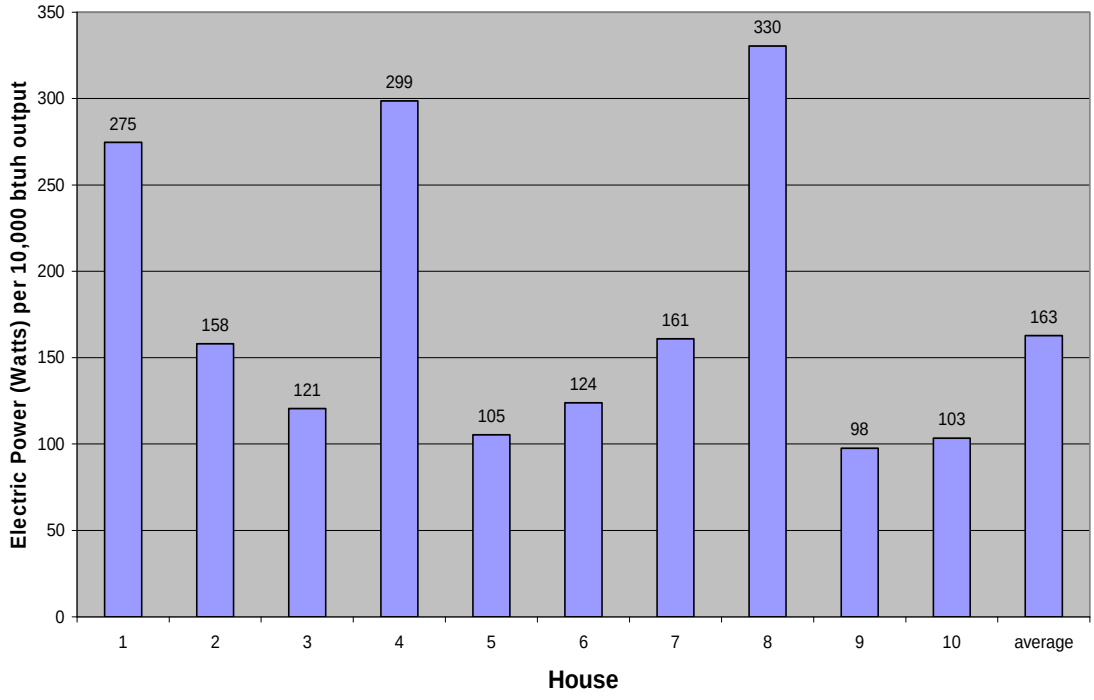
9.6 Ground Loop Pump

The electric power draw for the ground loop pumps ranged of 98 to 330 watts per 10,000 BTUh of heat pump output (heating mode) with a weighted average draw of 163 watts per 10,000 BTUh (see Chart #5 below).

The two poorest performers were on closed loop two stage systems that had pumps that were not staged and were fixed at the second stage flow rate whether the system was on first stage or second stage heating. These systems had a fluid flow rate of approximately 6 usgpm/nominal ton on first stage heating. The third highest pump draw of 275 watts per 10,000 BTUh of heat pump output was for the only open loop system being monitored.

The loop pumps on the seven other homes had draws of less than 161 watts per 10,000 BTUh of heat pump output (heating mode). Five of these systems were single stage units and one was a two stage heat pump that also had a two stage ground loop pump system.

Chart #5: Loop Pump Electrical Power Draw per 10,000 Btuh of Heat Pump Output (Heating Mode)



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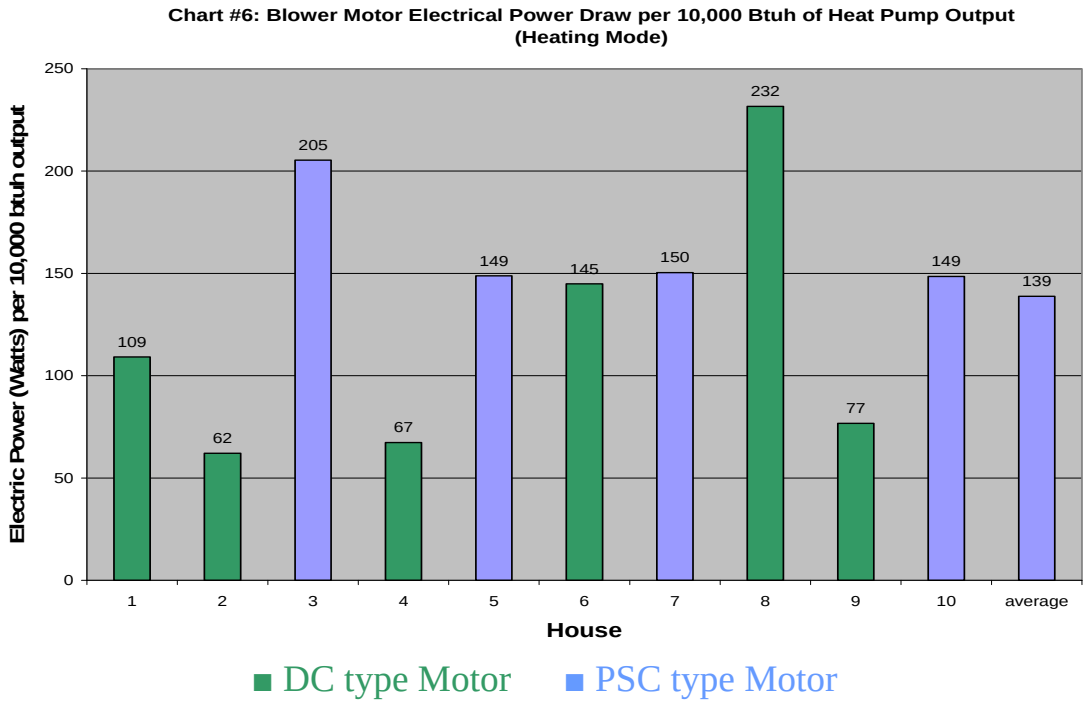
9.7 Fan Motor

Six of the ten units have an energy efficient brushless permanent magnet DC type motor and four have a permanent split capacitor (PSC) motor. One unit (house # 3) was a combination unit that had a PSC fan motor and hydronic loop pumps included in the fan energy. The electrical power draw ranged from 62 to 232 watts per 10,000 BTUh of heat pump output (heating mode) with an average of 139 watts (See Chart #6 below).

Three of the four PSC motors had approximately the same fan motor energy consumption (149-150 watts per 10,000 BTUh of heat pump output). The fourth PSC motor had a fan motor energy consumption of 205 watts per 10,000 BTUh of heat pump output. Three of the brushless permanent magnet DC type motors had the lowest power consumption (62 to 77 watts per 10,000 BTUh of heat pump output) but the consumption for all six varied greatly (62 to 232 watts per 10,000 BTUh of heat pump output).

The fan motor with the highest usage (232 watts/10,000 Btu) was actually a DC type motor. Duct design did not appear to be the cause of this high usage. Part of the reason that this fan motor used more energy than expected was that it ran a lot of hours at high speed while the compressor was stuck in first stage heating. The two other DC motors had fan motor consumptions that were slightly lower than the PSC motors.

A brushless permanent magnet DC type motor should use less than half of the energy as a PSC type motor.



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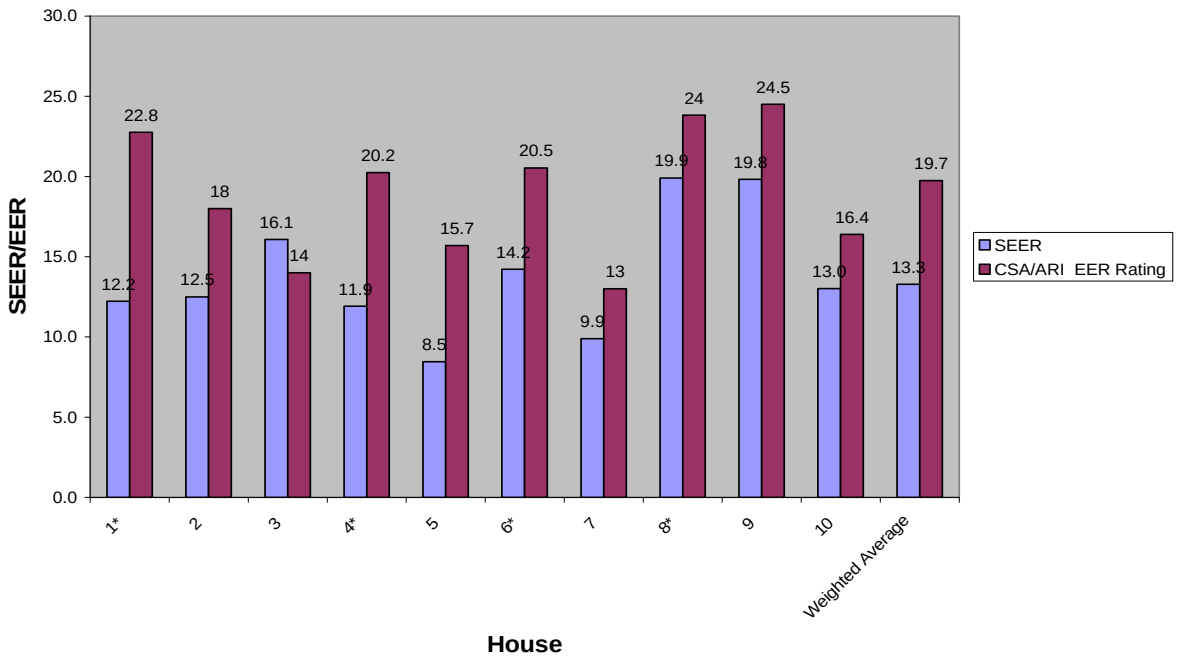
10.0 Cooling Season Performance

The ground source heat pump CSA 13256 test standard "Water-source heat pumps-Testing and rating for performance" rates cooling efficiency by an Energy Efficiency Ratio. Similar to the COP ratio, the EER is an instantaneous test based on specified conditions.

Central split air conditioning systems which are the most common residential cooling systems in Manitoba are rated by SEER (Seasonal Energy Efficiency Ratio). The SEER rating is supposed to provide a customer with a more accurate value to compare operating costs between units over an entire cooling season. The current minimum SEER rating for a central air conditioner is 13.

The test data showed that the field monitored Seasonal Energy Efficiency Ratio (SEER) during the cooling season for these ground source heat pump systems ranged from 8.5 to 19.9 with an average of 13.3 over the 2007 cooling season. SEER is defined as the total energy (heat) removed by the heat pump system (Btu's) divided by the total energy input to the system (watt hours) over one cooling season. The weighted average manufacturer rated EER of the ten units included in this study is 19.7 based on the CSA 13256 test standard (see chart # 7 below).

Chart # 7: Field Monitored SEER versus ARI/CSA EER Rating



* CSA/ARI EER Ratings for two stage units is a weighted average of the part load and full load ratings based on actual compressor part load and full load run hours (cooling mode).

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Similar to COP, the SEER of a ground source heat pump will generally be lower than the manufacturer's stated EER (EER based on CAN/CSA 13256 Test Standard "Water-source heat pumps-Testing and rating for performance").

This is due to the fact the test standard:

1. is an instantaneous test that does not include cycling losses
2. may not reflect actual system installation and design
3. only includes the fluid pumping power required to overcome the resistance of the unit itself (not the bore field piping).
4. only includes the fan power required to overcome the resistance of the unit itself (not the connected ductwork)
5. does not account for variations in entering water temperatures
6. does not account for variable homeowner operation
7. does not account for lack of system maintenance

The ground loop pumps delivered an average of 0.75 LPS (11.9 USGPM) per minute and had an electric draw of 750 watts. The CSA test standard allows for a default pumping power energy of 115 watts to move11.9 USWG of fluid.

The calculated fan energy (based on the CSA 13256 test standard) to only include the power to overcome the resistance of the average size of heat pump within the study was 256 watts. The actual average fan power draw in the homes that were monitored was 536 watts.

The average annual electricity consumption for these units during the cooling season was 772 kWh ($49). The estimated average annual cooling savings compared to a central air conditioner with a SEER of 13 is 17 kWh was $1. This may not be fair comparison since the assumed SEER of 13 for central air conditioners is at test conditions and may not reflect the actual field performance of these units. Actual field performance of conventional central air conditioners could also be expected to be lower than laboratory test results which could increase the potential cooling savings.

The single stage ground source heat pumps operated between 94 and 348 hours in the cooling mode. The two stage units operated between 195 and 541 hours in the cooling mode. The average equivalent full load cooling hours was 218 hours.

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11.0 Domestic Hot Water Heater Savings

The ground source heat pump desuperheater provides energy for water heating and thereby reduces electric water heating energy consumption.

In the winter, when the heat pump is delivering heat energy to the house, some of that heat energy is diverted to heat the domestic hot water; therefore it is assumed that the energy being delivered to the domestic hot water system is at the same COP as the heating system.

In summer, the heat pump is removing heat from the house and rejecting it to the ground loop. Some of this heat energy is diverted to the desuperheater and to the domestic hot water heater. This energy is considered "free" heat because it would have otherwise been rejected to the ground. However, in heating dominated climates with significantly unbalanced ground loads, the desuperheater also utilizes some of the heat that could have been rejected back to the ground in the cooling season. This causes the ground load to be even more seasonally unbalanced. This can be compensated for by increasing the size of the borefield (closed-loop systems) but this would increase the initial capital cost.

One desuperheater pump failed during the study period, therefore the desuperheater did not provide any heat to the domestic hot water system. Another pump was found to be defective at the start of the study but was replaced.

The homeowner's estimated annual savings ranged from 0 kWh to 1142 kWh with an average annual savings of 610 kWh at a value of $38, including the one system that was not working. The average savings increased to 678 kWh ($43) per year when the failed unit was excluded from the average.

A common trade practice to improve the output of a desuperheater that is directly connected to an electric storage water heater is to lower the temperature setting on the bottom element. The lower setting allows the desuperheater to provide more heat to the water heater since the element will not come on as frequently and it provides a lower inlet water temperature to the desuperheater which increases the output of the desuperheater. An issue was discovered during the study related to this practice. The hot water heater could only have a reduced temperature setting on the lower element during the heating season. The setting had to be increased in the non-heating season to meet the customer's hot water requirements. This was determined to be necessary because the heat pump did not operate for many hours in the summer period therefore the desuperheater could not provide much heat to the hot water heater and the customers would run out of hot water. A more effective solution promoted by contractors is to install a second water heater as a pre-heat tank. Although more effective, this increases the capital cost to the customer by an additional cost that is estimated at $500-$800.

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The National Plumbing Code of Canada (2005) requires that the temperature setting of electric water heaters be 60 ^{o}C (140 ^{o}F) to minimize the potential of bacterial growth in the water heater. This is also the factory setting of electric water heaters. Almost all of the homes in the study had hot water delivery temperatures lower than 60 ^{o}C (140 ^{o}F). Lowering the hot water heater temperature to increase the heat energy benefit provided by the desuperheater could potentially promote the growth of bacteria in the water heater which could become a health hazard.

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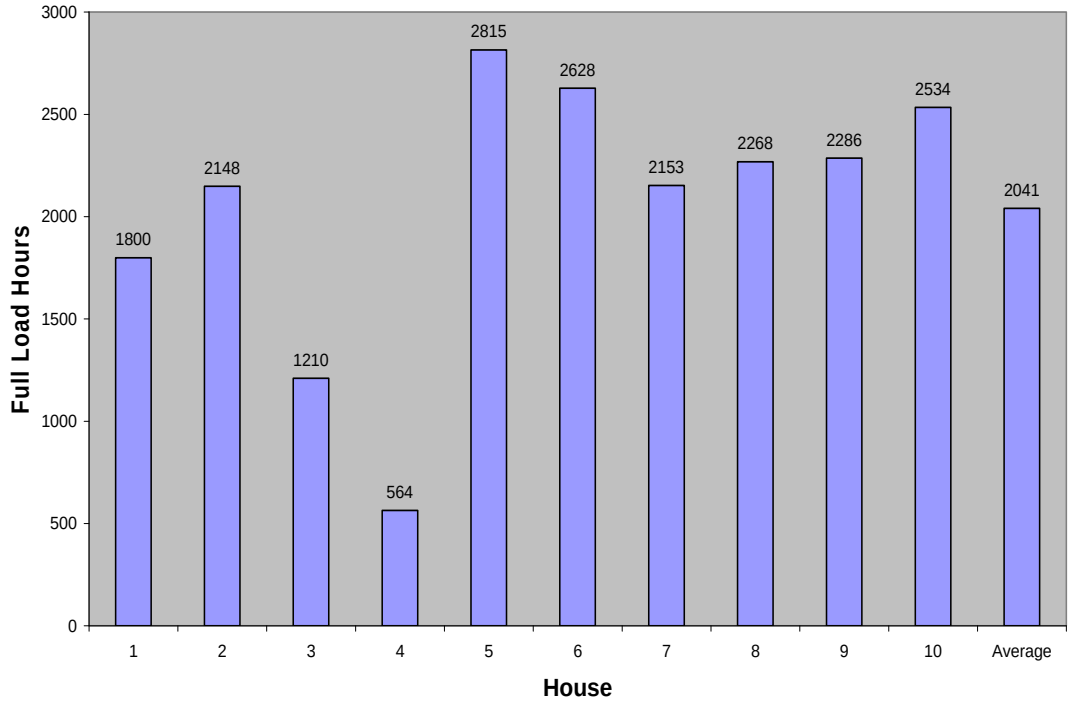
12.0 Operating Statistics

12.1 Run Hours Heating

The heat pumps operated between 564 and 2815 full load hours with an average of 2041 equivalent full load hours in the heating mode (see Chart #7 below). The home that had the lowest run hours had the heating requirements offset by constantly operating three dehumidifiers throughout the winter. These dehumidifiers effectively operated as space heaters at an SCOP of 1. The other homes did not operate any significant electrical loads in the home and did not utilize any other sources of heat.

House # 3 had the second lowest heating run hours (1,210) and the lowest cooling run hours (94). This was probably due to the heat pump unit itself being over-sized for the application. The unit is a single stage model that has a heating capacity output that was greater than most others in the study. The unit was installed in a new smaller energy efficient home that used the lowest amount of energy during the study period.

Chart # 8: Equivalent Annual Full Load Hours (Heating)



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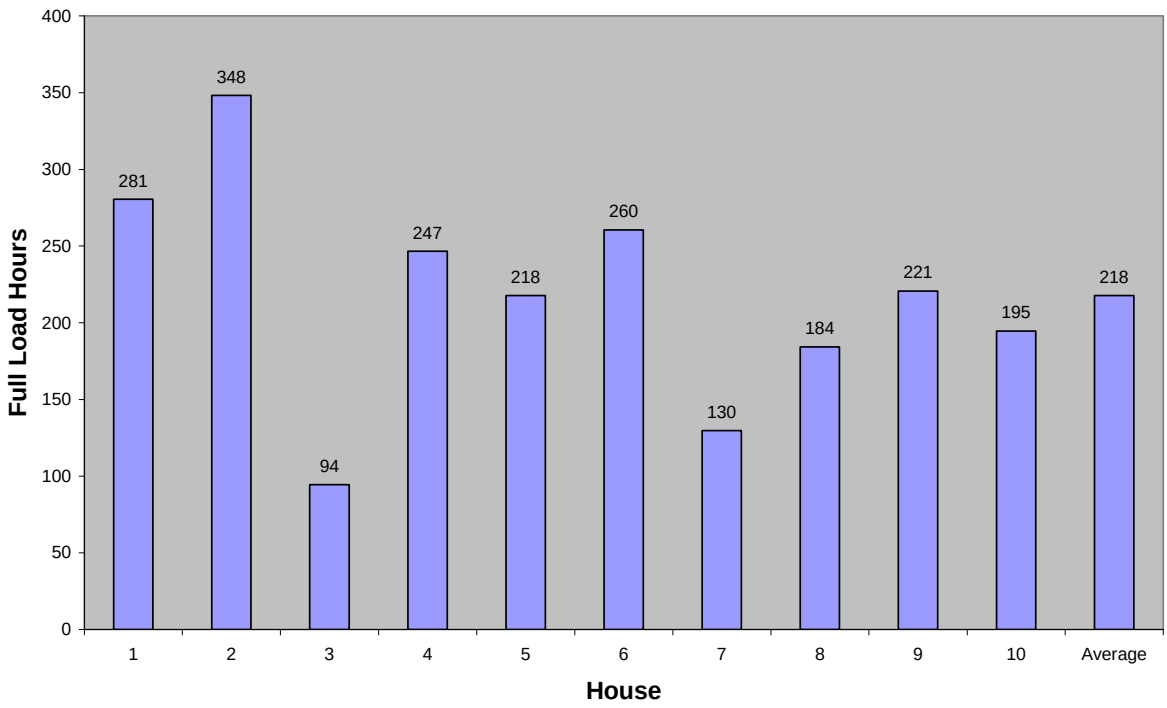
12.2 Run Hours Cooling

In cooling mode, the homes operated between 94 and 348 full load hours with an average of 218 equivalent full load hours (See Chart # 8 below). The average operating hours for all two stage units showed that they operated 82% of the time on first stage cooling. One of the two stage unit's had an actual annual run time of 541 hours in the cooling mode.

Chart # 9: Equivalent Annual Full Load Hours (Cooling)



There are significant variations in the heating and cooling requirements of homes in Manitoba. The study demonstrated that this variation equated to a load imbalance on the ground loop of approximately 5 units of heat extracted during the heating season for every 1 unit rejected to the ground loop in the summer. This imbalance must be considered when designing and installing a ground loop system.

12.3 Number of Starts

The systems started between 3,026 to 19,350 times per year, with an average of 10,453 starts (see Chart # 10 on page 25). The average number of starts in the heating mode was 9,351 and the average number of starts in the cooling mode was 1,102.

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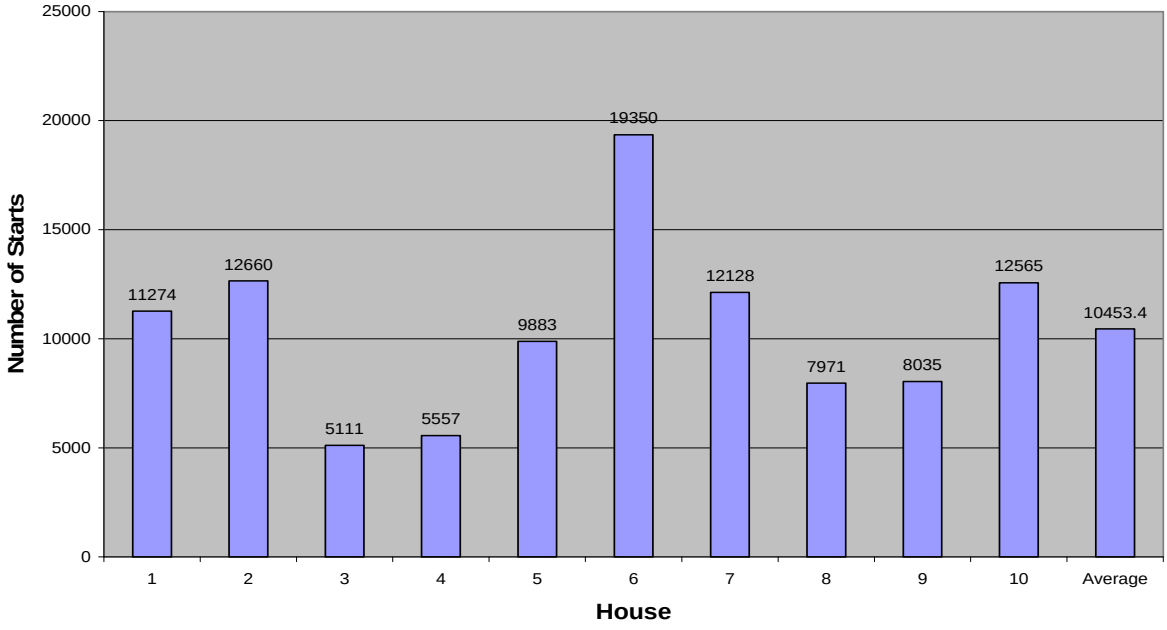
The high number of starts is significant because it can cause power quality issues in some homes. The most significant issue appears to be the frequent flickering or momentary dimming of lights in some homes when the heat pump unit starts due to the high in-rush current required to start the compressor. The compressor in-rush current lasts a fraction of a second and is approximately 10 times the running current. Compact fluorescent lights appear to be less susceptible to flicker compared to other types of lights. Incandescent sources including halogen lights appear to be the most flicker susceptible type of light source.

Manitoba Hydro has installed and tested two high torque start kits (basically an additional capacitor) on two different compressors to determine whether the start kits could significantly reduce the in-rush currents at compressor start-up. These kits are intended for hard starting compressors but it has been suggested that they can significantly reduce the in-rush current of the compressor motor. In both cases, the kits only slightly reduced the in-rush current and did not alleviate the issue of dimming lights (flicker).

Manitoba Hydro has recently installed and tested a newly released electronic soft start device that can be installed on specific models of heat pumps and compressors. This device appears to significantly reduce the in-rush current of the compressor motor. The preliminary test of this device on one compressor showed a 60% reduction of in-rush current at start-up. Manitoba Hydro will be conducting further field tests of this device.

Chart #10: Total Annual Compressor Starts



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13.0 Conclusion

The results of this study indicate that there are potentially significant energy savings in a Manitoba climate when utilizing a ground source heat pump compared to electric resistance heat.

Annual energy savings estimates for a ground source heat pump compared to electric heat should utilize an estimated Seasonal Coefficient of Performance (SCOP) instead of the ARI/CSA certified steady state COP. The estimated SCOP can be calculated by accounting for the additional fan, pump, and auxiliary heater electricity requirements that are not included in the CSA/ARI test standard.

The cooling season savings when compared to a new central air conditioner does not appear to be significant. The major benefit for a ground source heat pump compared to a central air conditioner is that the unit itself is indoors and not exposed to the outdoor elements.

Domestic water heating savings from the desuperheater in a heating dominated climate may not justify the capital cost and maintenance costs connected to the desuperheater. There may also be a health and safety issue with respect to the water heater storage temperatures being set lower than the National Plumbing Code requirement. This practice may increase the effectiveness of the desuperheater but could promote bacterial growth in the water heater.

Entering fluid temperature data collected during the study period were within reasonable design parameters. However, the closed systems being monitored were still relatively new, between one and three years old. This study does not provide enough data to determine the sustainability of long term loop and system performance.

The systems operated for an average of 2041 equivalent full load hours in heating mode and only 218 hours in cooling mode. This causes an imbalance to the ground of approximately 5 to1 for heat being extracted from the ground versus heat that is being rejected to the ground. This thermal imbalance could cause significant issues with the heat pump's long term sustainable performance if it was not properly considered at the design phase.

The significant in-rush currents and the high numbers of starts associated with the compressors have the potential to cause a momentary dimming of lights (flicker) or other power quality issues. Ensuring that the electrical system supplying power to the heat pump is robust and utilizing lights that are less susceptible to flicker could help reduce the effects of flicker.

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14.0 Recommendations

Customers should be provided with energy usage and savings based on an estimated Seasonal Coefficient of Performance (SCOP) that can be achieved and sustained over the expected operating life of the system.

During the monitoring period, several problems with some of the heat pump systems were discovered by the data collected through the monitoring equipment. For this reason, systems should be commissioned after the original installation and re-commissioned periodically to ensure proper operation. Installation of basic, permanently mounted metering equipment such as a flow meter, temperature probes on the ground loop and a run hour meter on the heat pump itself could be of significant benefit to both customers and geothermal contractors in diagnosing /trouble shooting problems and maintain proper operation.

Long term monitoring of bore fields in a cold climate such as Manitoba should be undertaken to determine the long term impact on the bore field due to the annual energy imbalance placed on the bore field.

More research and development (R&D) is required to find solutions for the power quality issues created by the starting characteristics of heat pump compressor motors. The R&D should include devices that can reduce the in-rush current, heat pump design, and electrical system design.

Contractors should ensure that the temperature setting of a customer's electric storage water heater is no less than 60 ^{o}C (140 ^{o}F) as required by the National Plumbing Code of Canada (2005) to avoid bacterial growth in the water heater.

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Appendix A

General House Descriptions

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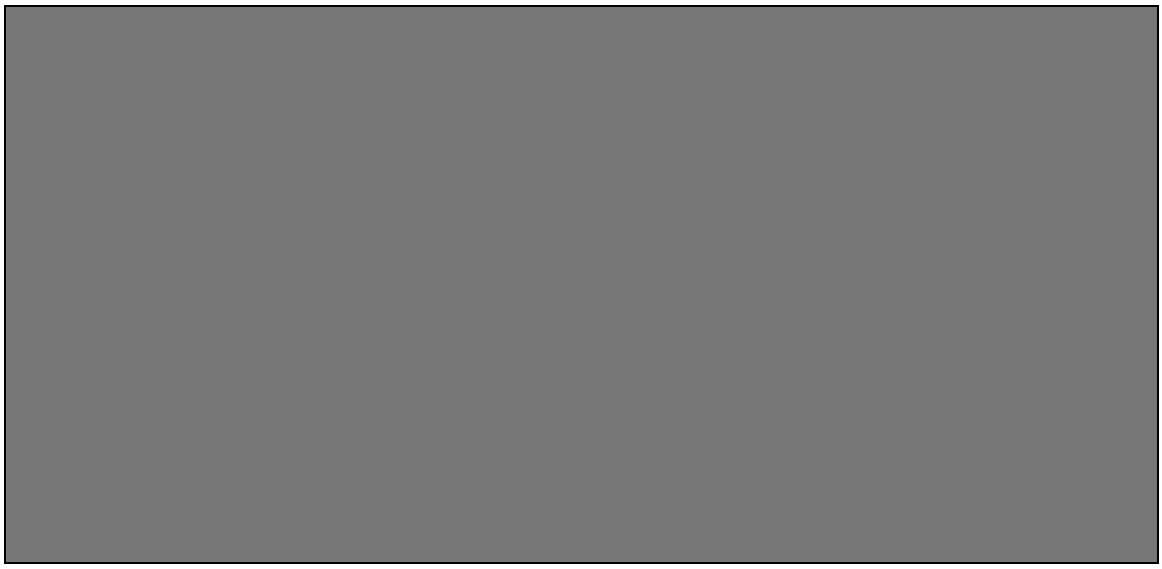
Hydro

House # 1



House Characteristics
Build Year: 1993
House Type: Two Storey
Sq. Footage: 2,100
Construction: Tight
Location: Dugald, Manitoba Area - Rural

Heat Pump Characteristics
Install Year: 1993
ARI Rated Heating Output: 40,500 BTUh
ARI Rated Cooling Output: 54,000 BTUh
ARI Rated COP: 3.4
ARI Rated EER: 16.5
Compressor: Two Stage
Fan Motor: DC - Variable
Distribution System: Forced Air

Ground Loop Characteristics
Type: Well to Well (Open Loop)
Well Spacing: 100 ft
Well Depth: 150 ft

Weather Data (based on Winnipeg Weather Station)
Normal Degree-Days Heating ^{o}C (^{o}F): 5778 (10400)
Normal Degree-Days Cooling ^{o}C (^{o}F): 186 (335 ^{o}F)
Outdoor Design Temperature Heating: -33 ^{o}C (-27 ^{o}F)
Outdoor Design Temperature Cooling: 30°C (86 ^{o}F)

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Hydro

House # 2

House Characteristics
Build Year: 1997
House Type: Two Storey
Sq. Footage: 2,400
Construction: Tight
Location: Flin Flon, Manitoba Area - Rural

Heat Pump Characteristics
Install Year: 2005
ARI Rated Heating Output: 37,800 BTUh
ARI Rated Cooling Output: 50,000 BTUh
ARI Rated COP: 3.6
ARI Rated EER: 18
Compressor: Single Stage
Fan Motor: DC - Variable
Distribution System: Forced Air

Ground Loop Characteristics
Type: Closed Lake Loop
Loop Length: 2,000 ft

Weather Data (based on Flin Flon Weather Station)
Normal Degree-Days Heating ^{o}C (^{o}F): 6083 (10949)
Normal Degree-Days Cooling ^{o}C (^{o}F): 85 (153 ^{o}F)
Outdoor Design Temperature Heating: -38 ^{o}C (-36 ^{o}F)
Outdoor Design Temperature Cooling: 27°C (81 ^{o}F)

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Hydro

House # 3

House Characteristics
Build Year: 2005
House Type: Bungalow
Sq. Footage: 1,150
Construction: Tight
Location: Winkler, Manitoba Area - Large town lot

Heat Pump Characteristics
Install Year: 2005
ARI Rated Heating Output: 47,400 BTUh
ARI Rated Cooling Output: 51,300 BTUh
ARI Rated COP: 3.2
ARI Rated EER: 14
Compressor: Single Stage
Fan Motor: PSC
Distribution System: Forced Air and Hydronic

Ground Loop Characteristics
Type: Horizontal Closed Loop - Slinky
Loop Length: 3,200 ft
Trench Depth: 7 ft

Weather Data (based on Morden Weather Station)
Normal Degree-Days Heating ^{o}C (^{o}F): 5404 (9727)
Normal Degree-Days Cooling ^{o}C (^{o}F): 223 (401 ^{o}F)
Outdoor Design Temperature Heating: -31 ^{o}C (-24 ^{o}F)
Outdoor Design Temperature Cooling: 31°C (88 ^{o}F)

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Hydro

House # 4

House Characteristics

Build Year: 1976
House Type: Bungalow
Sq. Footage: 1,680
Construction: Average
Location: Ile des Chenes, Manitoba Area - Rural

Heat Pump Characteristics

Install Year: 2003
ARI Rated Heating Output: 35,400 BTUh
ARI Rated Cooling Output: 52,800 BTUh
ARI Rated COP: 3.7
ARI Rated EER: 17.5
Compressor: Two Stage
Fan Motor: DC - Variable
Distribution System: Forced Air

Ground Loop Characteristics

Type: Vertical Closed Loop
Loop Length: 2,400 ft
Borehole Depth: 70 ft
# of Boreholes: 19
Separation (grid) 10 ft

Weather Data (based on Winnipeg Weather Station)

Normal Degree-Days Heating ^{o}C (^{o}F): 5778 (10400)
Normal Degree-Days Cooling ^{o}C (^{o}F): 186 (335 ^{o}F)
Outdoor Design Temperature Heating: -33 ^{o}C (-27 ^{o}F)
Outdoor Design Temperature Cooling: 30°C (86 ^{o}F)

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Hydro

House # 5

House Characteristics
Build Year: 1977
House Type: Bungalow
Sq. Footage: 1,049
Construction: Average
Location: Eriksdale, Manitoba Area - Rural

Heat Pump Characteristics
Install Year: 2004
ARI Rated Heating Output: 37,300 BTUh
ARI Rated Cooling Output: 46,400 BTUh
ARI Rated COP: 3.6
ARI Rated EER: 15.7
Compressor: Single Stage
Fan Motor: PSC
Distribution System: Forced Air

Ground Loop Characteristics
Type: Horizontal Closed Loop - Slinky
Loop Length: 5,000 ft
Trench Depth: 10 ft

Weather Data (based on Ashern Weather Station)
Normal Degree-Days Heating ^{o}C (^{o}F): 6206 (11171)
Normal Degree-Days Cooling ^{o}C (^{o}F): 118 (212 ^{o}F)
Outdoor Design Temperature Heating: -34 ^{o}C (-29 ^{o}F)
Outdoor Design Temperature Cooling: 29°C (84 ^{o}F)

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Hydro

House # 6

House Characteristics
Build Year: 1964
House Type: Bungalow
Sq. Footage: 1,896
Construction: Very Loose
Location: Swan River, Manitoba Area - Rural

Heat Pump Characteristics
Install Year: 2005
ARI Rated Heating Output: 47,000 BTUh
ARI Rated Cooling Output: 68,000 BTUh
ARI Rated COP: 3.8
ARI Rated EER: 16
Compressor: Two Stage
Fan Motor: DC - Variable
Distribution System: Forced Air

Ground Loop Characteristics
Type: Horizontal Closed Loop - Two Pipe
Loop Length: 4,000 ft
Trench Depth: 8 ft

Weather Data (based on Swan River Weather Station)
Normal Degree-Days Heating ^{o}C (^{o}F): 6083 (10949)
Normal Degree-Days Cooling ^{o}C (^{o}F): 103 (185 ^{o}F)
Outdoor Design Temperature Heating: -36 ^{o}C (-33 ^{o}F)
Outdoor Design Temperature Cooling: 29°C (84 ^{o}F)

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House # 7

House Characteristics

Build Year: 1925
House Type: Two Storey
Sq. Footage: 2,148
Construction: Very Loose
Location: Souris, Manitoba Area - Town Lot

Heat Pump Characteristics

Install Year: 2003
ARI Rated Heating Output: 48,000 BTUh
ARI Rated Cooling Output: 45,000 BTUh
ARI Rated COP: 3.2
ARI Rated EER: 13
Compressor: Single Stage
Fan Motor: PSC
Distribution System: Forced Air

Ground Loop Characteristics

Type: Vertical Closed Loop
Loop Length: 1,600 ft
Borehole Depth: 100 ft
# of Boreholes: 8
Separation (line) 10 ft

Weather Data (based on Souris Weather Station)

Normal Degree-Days Heating ^{o}C (^{o}F): 5810 (10458)
Normal Degree-Days Cooling ^{o}C (^{o}F): 137 (247 ^{o}F)
Outdoor Design Temperature Heating: -33 ^{o}C (-27 ^{o}F)
Outdoor Design Temperature Cooling: 31°C (88 ^{o}F)

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House # 8

House Characteristics

Build Year: 2005
House Type: Bungalow
Sq. Footage: 1810
Construction: Tight
Location: Brandon, Manitoba area - Rural

Heat Pump Characteristics

Install Year: 2005
ARI Rated Heating Output: 47,000 BTUh
ARI Rated Cooling Output: 68,000 BTUh
ARI Rated COP: 3.8
ARI Rated EER: 16
Compressor: Two Stage
Fan Motor: DC - Variable
Distribution System: Forced Air

Ground Loop Characteristics

Type: Vertical Closed Loop
Loop Length: 2,400 ft
Borehole Depth: 100 ft
# of Boreholes: 12
Separation (grid) 10 ft

Weather Data (based on Brandon Weather Station)

Normal Degree-Days Heating ^{o}C (^{o}F): 5951 (10712)
Normal Degree-Days Cooling ^{o}C (^{o}F): 119 (214 ^{o}F)
Outdoor Design Temperature Heating: -33 ^{o}C (-27 ^{o}F)
Outdoor Design Temperature Cooling: 31°C (88 ^{o}F)

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House # 9

House Characteristics
Build Year: 1993
House Type: Bungalow
Sq. Footage: 1,225
Construction: Tight
Location: Anola, Manitoba Area - Rural

Heat Pump Characteristics
Install Year: 2005
ARI Rated Heating Output: 24,000 BTUh
ARI Rated Cooling Output: 34,000 BTUh
ARI Rated COP: 3.9
ARI Rated EER: 24.5
Compressor: Two Stage
Fan Motor: DC - Variable
Distribution System: Forced Air

Ground Loop Characteristics
Type: Horizontal Closed Loop - Slinky
Loop Length: 3,000 ft
Trench Depth: 7 ft

Weather Data (based on Winnipeg Weather Station)
Normal Degree-Days Heating ^{o}C (^{o}F): 5778 (10400)
Normal Degree-Days Cooling ^{o}C (^{o}F): 186 (335 ^{o}F)
Outdoor Design Temperature Heating: -33 ^{o}C (-27 ^{o}F)
Outdoor Design Temperature Cooling: 30°C (86 ^{o}F)

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House # 10

House Characteristics

Build Year: 2002
House Type: Cab-Over
Sq. Footage: 1,878
Construction: Tight
Location: Winnipeg, MB - Suburban Lot

Heat Pump Characteristics

Install Year: 2002
ARI Rated Heating Output: 36,900 BTUh
ARI Rated Cooling Output: 48,908 BTUh
ARI Rated COP: 3.7
ARI Rated EER: 16.4
Compressor: Single Stage
Fan Motor: PSC
Distribution System: Forced Air

Ground Loop Characteristics

Type: Vertical Closed Loop
Loop Length: 1,600 ft
Borehole Depth: 70 ft
# of Boreholes: 11
Separation (line) 10 ft

Weather Data (based on Winnipeg Weather Station)

Normal Degree-Days Heating ^{o}C (^{o}F): 5778 (10400)
Normal Degree-Days Cooling ^{o}C (^{o}F): 186 (335 ^{o}F)
Outdoor Design Temperature Heating: -33 ^{o}C (-27 ^{o}F)
Outdoor Design Temperature Cooling: 30°C (86 ^{o}F)

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Appendix B

Map of Monitored Sites

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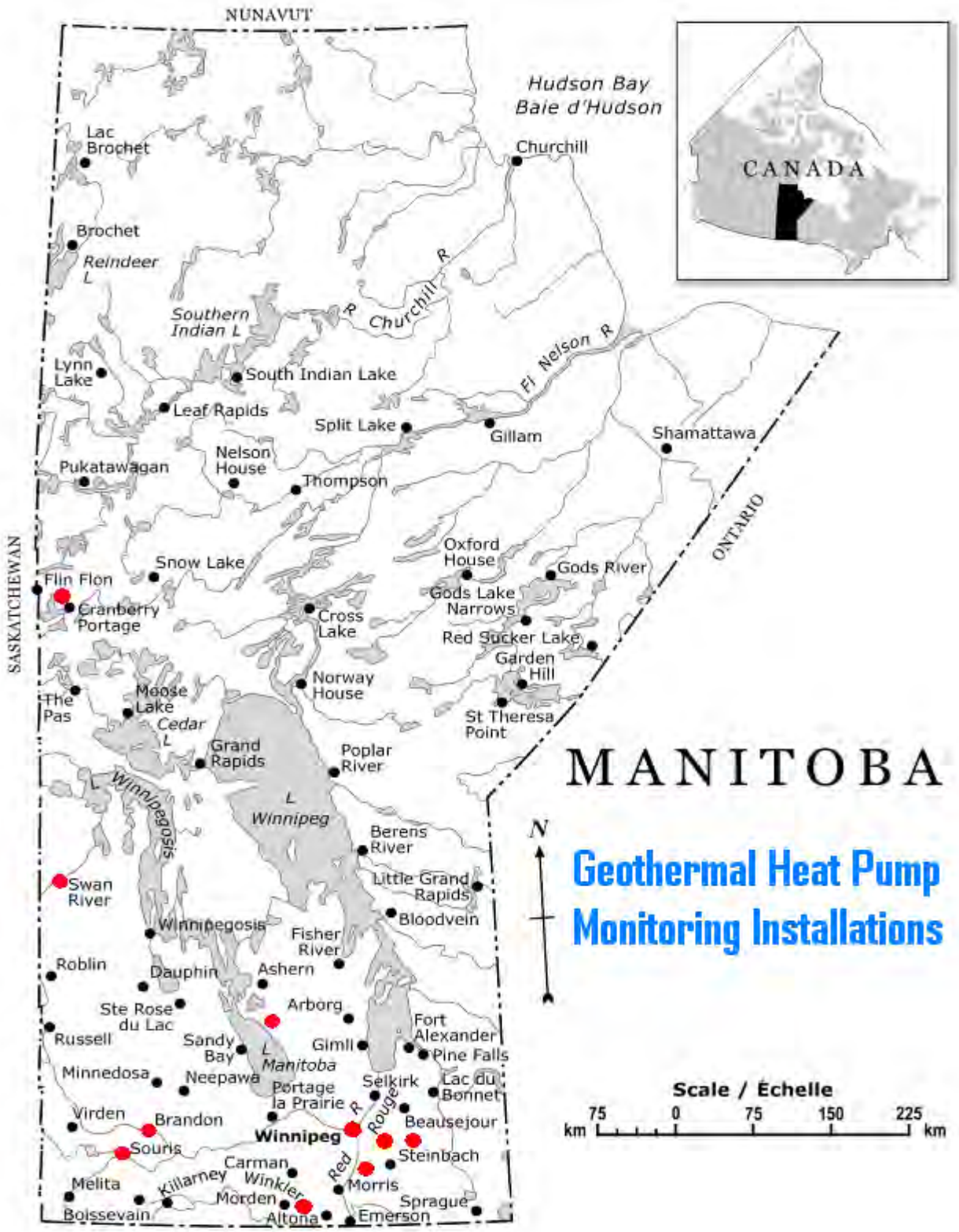
Hydro



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Appendix C

Data Acquisition Devices

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C.1 RTD Temperature Sensors:

Specifications: Elkor Technologies Inc.
No: ET-TP-U-1000/4
Type: 385, 1000 Ohm, Platinum, 4" Probe
Enclosure: 1/4" stainless steel (316) tubing
Conductor: 11' 105°C rated

Accuracy: Class B
± 0.5 °F @ 32 °F to ± 8.3 °F @ 1562 °F
± 0.3 °C @ 0 °C to ± 4.6 °C @ 850 °C

Note: Ground source temp span = 32°F to 65°F (0°C to 18°C)
Class B approximate errors:
Avg Error = ± 1.5% (per RTD)
Avg ΔT error = ± 3.0 %

Repeatability: better than 0.8% (-100°C to 100°C)

Response Time: Probe T (0.625) better than 10 seconds

C.2 Current Transducers:

Specifications: Magnalab Inc.
Type: SCT-0750
Output: 0.333 mV

Accuracy: ± 1.0% of measured value
(10% to 130% of rated current)

C.3 Potential Transducers:

Specifications: Highland.
Type: C282
Output: 0.333 mV

Accuracy: ± 1.0% of measured value

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C.4 Ground Loop Flow Meter:

Specifications:	Dwyer Instruments Inc. Type: UV-3112 range 2.0-20.00 GPM (8-76 LPM) UV-5112 range 4.0-40.00 GPM (20-150 LPM)
Accuracy:	± 2% @ 70 °F ± 2°F (21.1°C) and 14.7 PSIA
Repeatability:	± 1% Full Scale @ 70 °F ± 2°F(21.1°C) and 14.7 PSIA
Scale Resolution:	0.5 USWG (2 litres)
Correction Factor:	For 25% Methanol with Specific Gravity of 0.95423

Correction Factor = Instrument Reading x 1.02

C.5 Water Meter:

Specifications:	ABB Water Meters Inc. Type: Industrial Positive Displacement C-700 Bronze, Magnetic Drive
Pulse Output:	Pulser Type “B” (2P) One contact closure = 1 litre

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C.6 Data Logger:

Specifications: ENERNET Corporation
Type: K20 Energy Recorder

RMS Current - 8 Channels
RMS Voltage - 8 Channels
RMS Power - 8 Channels
kWh - 8 Channels
kVAh - 8 Channels
Power Factor - 8 Channels

Analog Inputs -8 Channels

Pulse/Runtime/- 8 Form "A" Channels
Rate Counter

Communications: Local RS-232 and modem.

Accuracy: Power/kWh: ± 0.4% of reading 100% to 5% of full scale at Unity to 0.5 PF.

Amps/Volts: ± 0.4% of full scale.

Power Factor: ± .02 PF, 100% to 5% of full scale.

Analog: ± 0.25% full scale

Resolution: Power: 0.1% FS minimum

kWh: 0.05% FS minimum

Amps/Volts: 0.1% FS minimum

Power Factor: 0.01 PF

Analog: Voltage: 1.0 mV
Resistance: 0.3 ohms
Temperature: 0.1°C

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Appendix D

Test Instruments and Reference Standards

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D1. **Reference Standards** (used to verify the accuracies of the insitu test instruments and data acquisition devices of the heat pump monitoring system) **:**

Digital thermometer:

Model:	Guideline Instruments Ltd. 50 °C to -30°C
Serial No:	57806
Certified by:	Measurement Canada (NRC Traceable)
Certificate No:	V05-0368

Voltmeter and Ammeter:

Model:	Radian Research Inc RM-15-14
Serial No:	501457
Certified by:	Measurement Canada (NRC Traceable)
Certificate No:	EP-04-048

D2. **Test Instruments** (used for insitu testing of each heat pump installation)**:**

Voltmeter and (Clip-on) Ammeter:

Model:	IDEAL 61-766
Serial No / ID No:	51001231 / MH05-118599

Power Quality Analyzer:

Model:	FLUKE 434
Serial No / ID No:	DM8980092 / MH05-118226

Digital Thermometer:

Model:	FLUKE 52 II
Serial No / ID No:	89870057 / MH05-118878

Temperature Probes (two probes):

Model:	FLUKE 80PK-8
ID No's:	MH05-118878-PCTP-01 and PCTP-01

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Appendix E

SCOP and SEER Calculation Constants

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D.1 Specific Heat for 25% Methanol:

25% Methanol SH = 0.95423 Btu/lb·F (3.995 kJ/kg·C)

D.2 Specific Gravity for 25% Methanol:

25% Methanol SG = 0.9678
(Confirmed by chemical analysis lab reports conducted on two samples of GL fluid)

D.3 Density of 25% Methanol:

Density 25% Methanol = 8.09 lb/USWG (0.97 kilogram/litre)

(8.34 lb/USG(density of water) x 0.97 S.G = 8.09 lb/USWG).

D.4 Ground Loop Flow Meter correction factor: for 25% Methanol:

Correction Factor = Flow Meter Reading x 1.02

Based on Dywer manufacturer's correction formula:

$$Q2 = Q1 \times \sqrt{1/S.G}$$

Where: Q2 = True Flow Value
Q1 = Flow meter reading
S.G = Specific Gravity of fluid

D.5 Specific Gravity of Water = 8.34 lb/USWG (1 kilogram/litre)

D.6 Specific Heat of Water = 1.0 Btu/lb·F (4.19 kJ/kg·C)

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Hydro

Appendix F

Monthly Heat Pump Energy Data

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Table # 1: House # 1 Monthly Heat Pump Data for 2007

Electricity Usage (kWh)	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Total Heat Pump System	1,802	1,898	1,106	642	322	269	436	293	308	532	944	1,168	9,720
Auxiliary Heater	46	210	56	44	-	-	-	-	8	-	42	-	406
Compressor Total	1,022	991	600	334	161	124	203	112	127	275	650	922	5,525
Compressor Heating	1,022	991	600	311	111	20	-	8	83	266	650	922	4,985
Compressor Cooling	-	-	-	23	51	105	203	105	44	9	-	-	539
FAN Total	204	205	135	98	75	88	113	92	90	114	156	186	1,556
FAN heating	187	192	103	54	18	3	-	3	28	59	125	143	914
FAN Cooling	-	-	-	7	16	33	64	39	17	3	-	-	180
FAN Circulating	17	13	33	37	41	51	49	58	58	53	31	43	484
Ground Loop Pump Total	487	466	302	175	98	88	145	79	75	150	297	324	2,687
Ground Loop Heating	487	466	302	160	61	11	-	4	44	143	297	324	2,300
Ground Loop Pump Cooling	-	-	-	15	38	77	145	75	31	7	-	-	388
Desuperheater Pump Total	45	29	32	18	11	10	15	9	9	18	35	46	277
Desuperheater Pump Heating	45	29	32	16	7	1	-	1	5	17	35	46	235
Desuperheater Pump Cooling	-	-	-	2	4	9	15	8	3	1	-	-	42
DHW Tank Electricity Consumption	130	183	258	310	317	345	327	304	332	326	216	174	3,223

													Totals
Ground Loop Heat of Extraction (kWh)*	3,470	4,108	2,351	1,369	388	66	-	26	288	962	2,196	2,772	17,995
Ground Loop Heat of Rejection (Btu)*	-	-	-	764,111	1,347,844	2,940,561	5,636,730	2,958,484	1,240,686	267,989	-	-	15,156,404

*Ground Loop Heat of Extraction and Heat of Rejection include loop pump electric power

													Weighted Average
Average COP	2.64	2.91	2.84	3.04	2.63	2.54	N/A	N/A	2.42	2.65	2.62	2.67	2.75
Average EER	N/A	N/A	N/A	15.5	11.7	12.2	12.0	12.1	12.3	12.8	N/A	N/A	12.2

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November 2013

Hydro

Table # 2: House # 2 Monthly Heat Pump Data for 2007

Electricity Usage (kWh)	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Total Heat Pump System	1,996	1,820	1,221	453	93	218	729	331	526	560	1,263	1,929	11,139
Auxiliary Heater	11	0	-	1	-	0	-	46	4	-	9	0	72
Compressor Total	1,532	1,401	913	344	68	151	520	201	449	428	954	1,474	8,435
Compressor Heating	1,532	1,401	913	344	61	21	2	20	427	856	954	1,474	8,005
Compressor Cooling	-	-	-	0	7	130	518	181	22	-	-	-	858
FAN Total	119	106	95	26	8	18	52	23	19	33	75	115	689
FAN heating	119	106	95	26	5	2	0	2	18	33	75	115	596
FAN Cooling	-	-	-	0	2	16	52	19	1	-	-	-	90
FAN Circulating	0	0	(0)	0	1	0	0	3	0	0	0	-	4
Ground Loop Pump Total	313	286	191	72	15	42	137	53	48	86	199	305	1,747
Ground Loop Heating	313	286	191	72	13	4	0	4	44	86	199	305	1,518
Ground Loop Pump Cooling	-	-	-	0	2	38	136	49	3	-	-	-	229
Desuperheater Pump Total	32	27	24	9	2	6	20	8	7	13	26	34	208
Desuperheater Pump Heating	32	27	24	9	2	1	0	1	6	13	26	34	174
Desuperheater Pump Cooling	-	-	-	0	0	6	20	7	0	-	-	-	34

													Totals
Ground Loop Heat of Extraction (kWh)*	4,126	3,849	2,526	959	205	83	4	77	728	1,342	2,473	2,914	19,287
Ground Loop Heat of Rejection (Btu)*	-	-	-	412	166,193	2,864,155	10,360,466	3,784,009	252,843	-	-	-	17,428,079

*Ground Loop Heat of Extraction and Heat of Rejection include loop pump electric power

													Weighted Average
Average COP	2.9	3.0	2.9	3.0	3.4	3.8	2.5	2.0	2.4	2.3	2.8	2.4	2.7
Average EER	N/A	N/A	N/A	10.8	14.0	13.7	12.1	13.2	7.7	N/A	N/A	N/A	12.5

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Table # 3: House # 3 Heat Pump Data for 2006**

Electricity Usage (kWh)	January***	February	March	April	May	June	July	August	September	October	November	December	Totals
Total Heat Pump System	435	1,116	907	327	212	69	152	70	147	465	762	1,049	5711
Auxiliary Heater	0	0	0	0	0	0	0	0	0	0	0	0	0
Compressor Total	300	746	631	234	156	39	89	43	99	298	527	732	3894
Compressor Heating	300	746	631	234	156	27	0	0	78	296	527	732	3727
Compressor Cooling	0	0	0	0	0	13	89	43	21	2	0	0	167
FAN Total	23	55	34	13	4	15	31	13	8	22	40	56	314
FAN heating	23	55	34	13	4	15	0	0	2	20	40	56	261
FAN Cooling	0	0	0	0	0	0	31	13	6	0	0	0	51
FAN Circulating	0	0	0	0	0	0	0	0	0	1	0	0	1
Ground Loop Pump Total	65	150	115	41	27	14	30	13	19	52	96	137	759
Ground Loop Heating	65	150	115	41	27	14	0	0	13	51	96	137	710
Ground Loop Pump Cooling	0	0	0	0	0	0	30	13	6	0	0	0	49
Desuperheater Pump Total	3	7	5	2	1	1	2	1	1	2	6	8	38
Desuperheater Pump Heating	3	7	5	2	1	1	0	0	0	2	6	8	35
Desuperheater Pump Cooling	0	0	0	0	0	0	2	1	0	0	0	0	3
Primary Hydronic Pump	20	48	40	15	11	0	0	0	5	16	28	43	226
Zone Pumps	25	110	82	22	13	0	0	0	15	76	65	73	480

**Used 2006 Data - Faulty temperature probe for part of 2007

***Installed 12 January, 2006

													Totals
Ground Loop Heat of Extraction (kWh)*	984	2,503	2,063	703	431.0	115	0	0	166	1,141	1,932	2,503	12539
Ground Loop Heat of Rejection (Btu)*	0	0	0	0	0	365,052	2,555,321	1,192,992	558,587	47524	0	0	4719477

*Ground Loop Heat of Extraction and Heat of Rejection include loop pump electric power

													Weighted Average
Average COP	3.11	3.10	3.14	3.01	2.90	2.76	0.00	0.00	2.35	3.36	3.40	3.25	3.17
Average EER	0.0	0.0	0.0	0.0	0.0	25.3	15.1	16.4	16.5	15.2	0.0	0.0	16.1

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Table # 4: House # 4 Monthly Heat Pump Data for 2006***

Electricity Usage (kWh)	January	February	March	April	May	June	July	August	September	October	November	December**	Totals
Total Heat Pump System	1162	448	206	223	98	254	471	333	91	284	433	222	4,227
Auxiliary Heater	7	0	0	0	0	0	0	0	0	0	0	0	7
Compressor Total	821	313	141	156	68	173	322	244	63	176	266	128	2,870
Compressor Heating	821	313	141	156	48	0	0	0	13	176	266	128	2,062
Compressor Cooling	0	0	0	0	20	173	322	244	50	0	0	0	808
FAN Total	48	36	39	19	15	38	70	27	6	15	36	39	389
FAN heating	40	24	15	11	5	0	0	0	1	15	26	27	165
FAN Cooling	0	0	0	0	2	30	53	17	5	0	0	0	108
FAN Circulating	9	11	24	8	8	9	17	10	0	0	10	11	116
Ground Loop Pump Total	259	98	44	49	22	51	96	71	21	83	124	58	976
Ground Loop Heating	259	98	44	49	13	0	0	0	6	83	124	58	734
Ground Loop Pump Cooling	0	0	0	0	7	51	96	71	15	0	0	0	241
Desuperheater Pump Total	36	13	6	7	2	0	0	0	1	11	17	8	101
Desuperheater Pump Heating	36	13	6	7	2	0	0	0	1	11	17	8	100
Desuperheater Pump Cooling	0	0	0	0	0	0	0	0	0	0	0	0	1

**2006 Data used - problem with downloading of data in 2007

***December 1-15, 2006 Data

													Totals
Ground Loop Heat of Extraction (kWh)*	1,703	583	268	321	87	N/A	N/A	N/A	43	581	876	404	4,866
Ground Loop Heat of Rejection (Btu)*	0	0	0	0	0	4,525,307	6,397,173	4,813,960	1,089,557	0	0	0	16,825,995

*Ground Loop Heat of Extraction and Heat of Rejection include loop pump electric power

													Weighted Average
Average COP	2.25	2.11	2.14	2.25	2.12	N/A	N/A	N/A	2.48	2.81	2.81	2.73	2.31
Average EER	N/A	N/A	N/A	N/A	N/A	15.1	10.9	11.9	12.9	N/A	N/A	N/A	11.9

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Hydro

Table # 5: House # 5 Monthly Heat Pump Data for 2007

Heat Pump Usage (kWh)	January	February	March	April	May***	June***	July	August	September	October	November	December	Totals
Total Heat Pump System	2,669	2,399	1,393	904	599	171	367	146	180	483	965	2,034	**12,309**
Auxiliary Heater	407	386	28	24	18	0	0	0	2	1	1	63	929
Compressor Total	1,630	1,448	989	639	415	109	238	95	132	350	706	1,437	8,186
Compressor Heating	1,630	1,448	989	639	408	26	0	0	129	350	706	1,437	7,759
Compressor Cooling	0	0	0	0	7	84	238	95	4	0		0	427
FAN Total	370	332	220	141	88	33	78	31	27	77	152	311	1,860
FAN heating	370	332	220	141	85	5	0	0	26	77	152	311	1,720
FAN Cooling	0	0	0	0	2	28	78	31	1	0	0	0	140
FAN Circulating	0	0	0	0	0	0	0	0	0	0	0	0	0
Ground Loop Pump Total	263	234	156	100	62	22	52	21	19	54	106	222	1,311
Ground Loop Heating	263	234	156	100	60	4	0	0	18	54	106	222	1,218
Ground Loop Pump Cooling	0	0	0	0	2	19	52	21	1	0	0	0	94
Desuperheater Pump Total**	0	0	0	0	16	6	0	0	0	0	0	0	23
Desuperheater Pump Heating	0	0	0	0	16	1	0	0	0	0	0	0	17
Desuperheater Pump Cooling	0	0	0	0	0	5	0	0	0	0	0	0	6

**DSH disconnected

***2006 Data:Communication Failed

													Totals
Ground Loop Heat of Extraction (kWh)*	5,637	4644	2,724	1,761	1,346	73	N/A	N/A	289	883	1,798	4,278	23,434
Ground Loop Heat of Rejection (Btu)*	0	0	0	0	145,140	1,813,875	4,019,586	1,499,425	43,080	0	0	0	7,521,105

*Ground Loop Heat of Extraction and Heat of Rejection include loop pump electric power

													Weighted Average
Average COP	3.01	2.84	2.84	2.84	3.19	2.94	N/A	N/A	2.55	2.72	2.75	2.99	2.91
Average EER				N/A	10	11	8	7	5	N/A	N/A	N/A	8

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Table # 6: House # 6 Monthly Heat Pump Data for 2007

Heat Pump Usage (kWh)	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Total Heat Pump System	2,337	2,295	1,696	1,059	503	286	485	466	548	786	1,455	2,440	14,356
Auxiliary Heater	0	0	0	0	0	0	0	0	0	0	0	0	0
Compressor Total	1,614	1,578	1,095	663	289	137	261	265	320	474	917	1,625	9,238
Compressor Heating	1,614	1,578	1,095	663	289	58	3	33	208	456	917	1,625	8,539
Compressor Cooling	0	0	0	0	0	79	258	232	112	18	0	0	698
FAN Total	349	342	301	212	132	108	146	131	148	196	306	419	2,790
FAN heating	337	336	284	182	82	21	1	7	59	143	277	408	2,136
FAN Cooling	0	0	0	0	0	29	85	67	38	7	0	0	226
FAN Circulating	12	7	16	30	50	58	60	57	51	46	29	11	428
Ground Loop Pump Total	336	343	250	148	63	33	63	58	65	94	191	346	1,993
Ground Loop Heating	336	343	250	148	63	12	1	6	39	90	191	346	1,826
Ground Loop Pump Cooling	0	0	0	0	0	21	63	52	26	4	0	0	167
Desuperheater Pump Total	38	32	50	36	19	7	14	11	14	22	41	50	335
Desuperheater Pump Heating	38	32	50	36	19	3	0	1	8	21	41	50	299
Desuperheater Pump Cooling	0	0	0	0	0	4	14	11	6	1	0	0	36

													Totals
Ground Loop Heat of Extraction (kWh)*	5,827	5,727	3,974	2,404	1,049	208	14	138	898	1,979	3,703	5,985	31,906
Ground Loop Heat of Rejection (Btu)*	0	0	0	0	0	2,457,275	7,303,671	5,449,659	2,756,938	476,925	0	0	18,444,468

*Ground Loop Heat of Extraction and Heat of Rejection include loop pump electric power

													Weighted Average
Average COP	3.35	3.34	3.19	3.16	3.14	3.05	3.56	3.80	3.70	3.63	3.43	3.30	3.33
Average EER	N/A	N/A	N/A	N/A	N/A	16.5	15.4	12.7	13.0	13.9	N/A	N/A	14.2

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Table # 7: House # 7 Monthly Heat Pump Data for 2007

Heat Pump Usage (kWh)	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Total Heat Pump System	1,948	2,055	1,308	767	376	87	388	74	330	609	1,292	2,065	**11,298**
Auxiliary Heater	7	0	0	0	0	0	0	0	0	0	0	0	7
Compressor Total	1,330	1,416	899	526	258	54	242	46	230	423	895	1,422	7,739
Compressor Heating	1,330	1,416	899	526	258	14	0	0	221	423	895	1,422	7,402
Compressor Cooling	0	0	0	0	0	40	242	46	9	0	0	0	337
FAN Total	297	305	193	112	55	16	70	13	48	88	192	300	1,688
FAN heating	293	305	193	112	55	3	0	0	45	88	192	300	1,585
FAN Cooling	0	0	0	0	0	13	70	13	3	0	0	0	98
FAN Circulating	4	0	0	0	0	0	0	0	0	0	0	0	4
Ground Loop Pump Total	307	332	204	118	57	15	68	13	48	88	199	342	1,793
Ground Loop Heating	307	332	204	118	57	3	0	0	46	88	199	342	1,696
Ground Loop Pump Cooling	0	0	0	0	0	13	68	13	3	0	0	0	97
Desuperheater Pump Total	8	2	12	10	6	2	8	2	5	10	6	1	71
Desuperheater Pump Heating	8	2	12	10	6	0	0	0	4	10	6	1	60
Desuperheater Pump Cooling	0	0	0	0	0	1	8	2	0.3	0	0	0	12

													Totals
Ground Loop Heat of Extraction (kWh)*	4067	4543	2824	1604	759	42	0	0	646	1209	2296	3204	21,194
Ground Loop Heat of Rejection (Btu)*	0	0	0	0	0	2,457,275	7,303,671	5,449,659	2,756,938	476,925	0	0	18,444,468

*Ground Loop Heat of Extraction and Heat of Rejection include loop pump electric power

													Weighted Average
Average COP	2.93	3.05	3.00	2.94	2.87	2.95	N/A	N/A	2.90	2.84	2.62	2.39	2.81
Average EER	N/A	N/A	N/A	N/A	N/A	10.28	9.60	11.13	9.57	N/A	N/A	N/A	9.89

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Table # 8: House # 8 Monthly Heat Pump Data for 2007

Heat Pump Usage (kWh)	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Total Heat Pump System	2,262	2,359	1,578	831	336	166	416	185	245	710	1,433	2,362	**12,884**
Auxiliary Heater	29	83	47	72	5	0	0	0	0	5	3	35	280
Compressor Total	1,351	1,389	901	437	181	73	205	85	130	404	852	1,411	**7,417**
Compressor Heating	1,351	1,389	901	433	153	6	0	0	117	403	852	1,411	7,016
Compressor Cooling	0	0	0	4	27	67	205	85	13	1	0	0	401
FAN Total	366	418	232	112	56	42	69	45	47	95	183	380	**2,046**
FAN heating	363	416	224	94	25	1	0	1	22	77	171	376	1,770
FAN Cooling	0	0	0	1	8	17	48	20	3	0.1	0	0	98
FAN Circulating	3	2	8	16	23	24	20	24	23	17	12	4	177
Ground Loop Pump Total	455	415	348	183	83	44	125	48	59	181	347	475	**2,764**
Ground Loop Heating	455	415	348	181	69	2	0	0	51	181	347	475	2,526
Ground Loop Pump Cooling	0	0	0	2	14	42	125	48	8	0.4	0	0	238
Desuperheater Pump Total	61	53	49	26	12	6	18	7	8	26	49	61	**376**
Desuperheater Pump Heating	61	53	49	26	10	0.3	0	0	7	26	49	61	342
Desuperheater Pump Cooling	0	0	0	0	2	6	18	7	1	0.0	0	0	34

													Totals
Ground Loop Heat of Extraction (kWh)*	2,548	2,755	1,687	787	241	12	0	0	209	677	1,427	2,517	12,860
Ground Loop Heat of Rejection (Btu)*	0	0	0	54,057	908,292	2,824,635	8,321,438	3,175,225	450,375	11,034	0	0	15,745,056

*Ground Loop Heat of Extraction and Heat of Rejection include loop pump electric power

													Weighted Average
Average COP	1.90	1.97	1.82	1.72	1.62	2.05	N/A	N/A	1.76	1.68	1.73	1.84	1.84
Average EER	N/A	N/A	N/A	5.3	16.8	21.4	20.4	19.5	18.3	7.3	N/A	N/A	19.9

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Hydro

Table # 9: House # 9 Monthly Heat Pump Data for 2007

Heat Pump Usage (kWh)	January	February	March	April	May	June	July	August	September	October	November	December	Totals
Total Heat Pump System	1,040	1,038	710	275	167	165	240	82	148	266	527	941	5,599
Auxiliary Heater	0	0	0	0	0	0	0	0	0	0	0	0	0
Compressor Total	771	782	526	204	95	77	129	31	67	162	378	709	3,932
Compressor Heating	771	782	526	204	88	11	0	0	55	162	378	709	3,686
Compressor Cooling	0	0	0	0	7	64	129	31	12	0	0	0	244
FAN Total	104	101	74	28	52	65	75	42	66	70	71	87	837
FAN heating	95	98	70	27	12	1	0	0	7	21	47	78	457
FAN Cooling	0	0	0	0	1	12	23	6	2	0	0	0	44
FAN Circulating	9	3	5	1	39	51	52	36	57	49	24	9	336
Ground Loop Pump Total	126	119	84	33	16	17	27	7	11	26	59	110	635
Ground Loop Heating	126	119	84	33	15	2	0	0	9	26	59	110	581
Ground Loop Pump Cooling	0	0	0	0	1	15	27	7	3	0	0	0	53
Desuperheater Pump Total	39	36	26	10	4.8	5.2	8.4	2.1	3.4	8	18	34	195
Desuperheater Pump Heating	39	36	26	10	4.4	0.5	0.0	0.0	2.6	8	18	34	178
Desuperheater Pump Cooling	0	0	0	0	0.4	4.5	8.4	2.1	0.8	0	0	0	16

													Totals
Ground Loop Heat of Extraction (kWh)*	2,603	2,632	1,802	721	337	42	0	0	245	694	1,523	2,243	12,842
Ground Loop Heat of Rejection (Btu)*	0	0	0	0	202,364	2,009,248	3,627,434	912,176	335,824	0	0	0	7,087,046

*Ground Loop Heat of Extraction and Heat of Rejection include loop pump electric power

													Weighted Average
Average COP	3.40	3.43	3.44	3.51	3.71	3.81	N/A	N/A	4.24	4.09	3.91	3.29	3.50
Average EER	N/A	N/A	N/A	5.3	16.8	21.4	20.4	19.5	18.3	7.3	N/A	N/A	19.9

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Hydro

Table # 10: House # 10 Monthly Heat Pump Data for 2007

Heat Pump Usage (kWh)	January	February	March	April	May	June	July	August	September	October	November**	December**	Totals
Total Heat Pump System	2,130	2,019	1,371	605	235	266	310	133	177	548	1,333	1,697	**10,824**
Auxiliary Heater	76	119	0	0	0	0	0	0	0	0	0	0	195
Compressor Total	1,481	1,368	986	436	155	155	199	80	98	399	961	1,219	**7,535**
Compressor Heating	1,481	1,368	986	436	136	15	0	0	98	399	961	1,219	7,097
Compressor Cooling	0	0	0	0	19	140	199	80	0	0	0	0	438
FAN Total	320	295	210	92	52	78	70	36	63	82	207	266	**1,772**
FAN heating	320	295	210	92	31	3	0	0	19	82	207	266	1,526
FAN Cooling	0	0	0	0	6	48	57	22	0	0	0	0	132
FAN Circulating	0	0	0	0	15	27	13	14	44	0	0	0	114
Ground Loop Pump Total	222	208	149	66	24	28	35	14	14	58	141	182	**1,140**
Ground Loop Heating	222	208	149	66	20	2	0	0	14	58	141	182	1,062
Ground Loop Pump Cooling	0	0	0	0	4	26	35	14	0	0	0	0	78
Desuperheater Pump Total	32	30	25	11	4.1	4.9	6	2	2	10	24	30	**182**
Desuperheater Pump Heating	32	30	25	11	3.5	0.4	0	0	2	10	24	30	169
Desuperheater Pump Cooling	0	0	0	0	0.6	4.5	6	2	0	0	0	0	14

**2006 Data:Temperature Probe Failed

													Totals
Ground Loop Heat of Extraction (kWh)*	4501	4091	2897	1288	349	40	0	0	269	1159	2727	3793	21,115
Ground Loop Heat of Rejection (Btu)*	0	0	0	0	457,841	3,423,369	4,520,959	1,753,028	0	0	0	0	10,155,197

*Ground Loop Heat of Extraction and Heat of Rejection include loop pump electric power

													Weighted Average
Average COP	3.01	2.92	3.00	3.02	2.72	2.80	N/A	N/A	2.91	3.01	2.94	3.13	3.00
Average EER	N/A	N/A	N/A	N/A	N/A	13.5	13.2	12.8	N/A	N/A	N/A	N/A	13.0

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Appendix G

Domestic Hot Water Data

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Hydro

Table # 11: Annual Domestic Hot Water Data for Monitored Houses

A	B	C	D	E	F	G	H	I	J	K
House	Average Water Heater Inlet Temperature (degrees Celsius)	Average Water Heater Outlet Temperature (degrees Celsius)	Hot Water Usage (litres)	Energy delivered to water usage (kWh)	Calculated Stand-By Loss (kWh)	Total Hot Water Energy (kWh) E + F	Hot Water Heater Electricity Usage (kWh)	Energy provided by Desuperheater (kWh) G-H	Electric Energy to Heat Pump (kWh)*	Net energy savings (kWh) I-J
1	7.5	55.5	55776	3105	1797	4901	3223	1678	569	1109
2	16.6	53.5	50954	2185	1865	4050	2260	1790	649	1142
3	15.3	49.6	45779	1834	2134	3967	3057	910	260	650
4	13.6	49.9	30176	1274	2448	3721	3334	388	153	235
5	12.9	44.0	23088	831	1211	2042	2042	0	0	0
6	12.8	52.5	43294	1995	909	2903	2224	679	216	463
7	14.4	50.0	47222	1950	1155	3105	2805	301	98	202
8	15.2	58.4	61728	3097	757	3854	2521	1333	748	585
9	14.6	46.0	46476	1700	1101	2800	1692	1109	272	836
10	12.1	48.8	55169	2352	927	3279	2026	1254	396	879
Average	13.5	50.8	45966	2032	1430	3462	2518	944	336	610

*Electric energy to heat pump in heating mode is the energy provided by the desuperheater divided by the COP of the heat pump system. The heat pump runs longer to satisfy the home's heating requirements since its heating capacity was reduced by the desuperheater.

*Electric energy to heat pump in cooling mode is the electric energy to the desuperheater pump only.

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Hydro

Table 12: Domestic Hot Water Data for House # 1

House # 1 Domestic Hot Water Data										
A	B	C	D	E	F	G	H	I	J	K
Month	Average Water Heater Inlet Temperature (degrees Celsius)	Average Water Heater Outlet Temperature (degrees Celsius)	Hot Water Usage (litres)	Energy delivered to water usage (kWh)	Calculated Stand-By Loss (kWh)	Total Hot Water Energy (kWh) E + F	Hot Water Heater Electricity Usage (kWh)	Energy provided by Desuperheater (kWh) G-H	Electric Energy to Heat Pump (kWh)*	Net energy savings (kWh) I-J
January	6.9	55.2	4629	260	153	412	130	282	107	176
February	6.9	56.4	4560	262	138	400	183	216	74	142
March	7.0	54.6	5334	295	153	447	258	189	66	123
April	6.9	55.1	5166	289	148	436	310	126	39	87
May	7.3	56.1	4282	242	153	395	317	77	23	55
June	8.2	57.2	4449	253	148	400	345	55	12	43
July	7.5	55.6	4340	242	153	395	327	68	18	50
August	8.5	55.8	3840	211	153	363	304	59	8	51
September	8.3	57.1	4560	258	148	406	332	74	22	52
October	8.1	55.2	4827	264	153	417	326	90	33	57
November	7.4	52.5	4546	238	148	386	216	170	65	105
December	7.1	55.2	5243	292	153	445	174	271	101	169
Annual	7.5	55.5	55776	3105	1797	4901	3223	1678	569	1109

Table 13: Domestic Hot Water Data for House # 2

House # 2 Domestic Hot Water Data										
A	B	C	D	E	F	G	H	I	J	K
Month	Average Water Heater Inlet Temperature (degrees Celsius)	Average Water Heater Outlet Temperature (degrees Celsius)	Hot Water Usage (litres)	Energy delivered to water usage (kWh)	Calculated Stand-By Loss (kWh)	Total Hot Water Energy (kWh) E + F	Hot Water Heater Electricity Usage (kWh)	Energy provided by Desuperheater (kWh) G-H	Electric Energy to Heat Pump (kWh)*	Net energy savings (kWh) I-J
January	16.8	53.8	3554	153	158	311	60	251	86	164
February	16.8	53.8	3528	152	143	295	62	233	79	154
March	15.9	53.1	4806	208	158	366	174	192	66	126
April	15.1	52.4	5008	217	153	370	264	106	36	70
May	15.6	53.3	5160	226	158	385	352	33	9	24
June	17.5	56.6	4718	214	153	367	319	49	7	42
July	18.9	53.8	4312	175	158	333	300	33	20	12
August	18.8	53.9	3254	133	158	291	229	62	10	52
September	16.9	51.6	4111	165	153	319	201	117	47	71
October	15.9	51.3	4027	166	158	324	165	159	70	89
November	17.6	53.5	3949	164	153	318	73	245	87	157
December	13.9	54.6	4527	214	158	372	61	311	132	179
Annual	16.6	53.5	50954	2185	1865	4050	2260	1790	649	1142

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Table 14: Domestic Hot Water Data for House # 3

House # 3 Domestic Hot Water Data										
A	B	C	D	E	F	G	H	I	J	K
Month	Average Water Heater Inlet Temperature (degrees Celsius)	Average Water Heater Outlet Temperature (degrees Celsius)	Hot Water Usage (litres)	Energy delivered to water usage (kWh)	Calculated Stand-By Loss (kWh)	Total Hot Water Energy (kWh) E + F	Hot Water Heater Electricity Usage (kWh)	Energy provided by Desuperheater (kWh) G-H	Electric Energy to Heat Pump (kWh)*	Net energy savings (kWh) I-J
January	14.0	46.1	1929	72	181	253	81	172	55	117
February	13.0	48.5	4752	196	164	359	220	139	45	94
March	12.4	53.9	5071	244	181	425	347	78	25	53
April	12.9	49.7	3423	146	175	322	294	28	9	19
May	15.2	53.1	3728	164	181	345	312	34	12	22
June	14.9	49.2	3511	140	175	315	300	15	5	9
July	16.8	48.8	3956	147	181	328	296	32	0	32
August	17.7	49.7	3968	147	181	329	291	38	0	38
September	17.1	50.5	4155	161	175	336	281	55	13	42
October	17.7	48.8	3911	141	181	322	240	83	24	58
November	16.5	48.3	3662	135	175	310	198	112	33	79
December	15.5	48.1	3713	140	181	322	198	124	38	86
Annual	15.3	49.6	45779	1834	2134	3967	3057	910	260	650

Table 15: Domestic Hot Water Data for House # 4

House # 4 Domestic Hot Water Data										
A	B	C	D	E	F	G	H	I	J	K
Month	Average Water Heater Inlet Temperature (degrees Celsius)	Average Water Heater Outlet Temperature (degrees Celsius)	Hot Water Usage (litres)	Energy delivered to water usage (kWh)	Calculated Stand-By Loss (kWh)	Total Hot Water Energy (kWh) E + F	Hot Water Heater Electricity Usage (kWh)	Energy provided by Desuperheater (kWh) G-H	Electric Energy to Heat Pump (kWh)*	Net energy savings (kWh) I-J
January	11.9	51.1	2403	109	208	317	264	53	23	29
February	14.9	49.6	2282	92	188	279	228	51	24	27
March	15.7	50.1	2421	96	208	304	239	66	31	35
April	11.9	49.7	2571	113	201	314	309	5	2	3
May	12.8	49.4	2810	120	208	327	326	1	1	1
June	14.4	48.7	2399	96	201	297	295	2	0.2	1
July	13.1	49.5	3376	143	208	351	341	10	0.4	9
August	13.5	50.5	2878	123	208	331	319	12	0.3	12
September	14.1	50.0	3226	134	201	336	314	22	8	14
October	12.7	49.4	2590	110	213	323	323	0	0	0
November	13.6	50.6	2277	98	201	299	269	30	11	19
December	14.3	50.8	943	40	208	248	107	141	52	89
Annual	13.6	49.9	30176	1274	2448	3721	3334	388	153	235

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Table 16: Domestic Hot Water Data for House # 5

House # 5 Domestic Hot Water Data										
A	B	C	D	E	F	G	H	I	J	K
Month	Average Water Heater Inlet Temperature (degrees Celsius)	Average Water Heater Outlet Temperature (degrees Celsius)	Hot Water Usage (litres)	Energy delivered to water usage (kWh)	Calculated Stand-By Loss (kWh)	Total Hot Water Energy (kWh) E + F	Hot Water Heater Electricity Usage (kWh)	Energy provided by Desuperheater (kWh) G-H	Electric Energy to Heat Pump (kWh)*	Net energy savings (kWh) I-J
January	11.2	40.0	1546	52	119	171	171	0	0	0
February	10.6	40.8	1447	51	110	160	160	0	0	0
March	12.1	42.4	1801	63	114	178	178	0	0	0
April	12.3	41.7	1972	67	112	180	180	0	0	0
May	11.1	47.9	2067	88	87	175	175	0	0	0
June	14.5	44.5	2086	73	87	160	160	0	0	0
July	14.2	46.1	1817	67	92	159	159	0	0	0
August	15.7	46.5	1874	67	94	161	161	0	0	0
September	13.2	45.4	3202	120	104	224	224	0	0	0
October	14.6	46.4	1552	57	83	140	140	0	0	0
November	13.4	45.6	1900	71	89	160	160	0	0	0
December	12.4	40.2	1824	59	116	175	175	0	0	0
Annual	12.9	44.0	23088	831	1211	2042	2042	0	0	0

2006 Data

The desuperheater pump failed on this unit and was not replaced.

Table 17: Domestic Hot Water Data for House # 6

House # 6 Domestic Hot Water Data										
A	B	C	D	E	F	G	H	I	J	K
Month	Average Water Heater Inlet Temperature (degrees Celsius)	Average Water Heater Outlet Temperature (degrees Celsius)	Hot Water Usage (litres)	Energy delivered to water usage (kWh)	Calculated Stand-By Loss (kWh)	Total Hot Water Energy (kWh) E + F	Hot Water Heater Electricity Usage (kWh)	Energy provided by Desuperheater (kWh) G-H	Electric Energy to Heat Pump (kWh)*	Net energy savings (kWh) I-J
January	10.8	52.6	2902	141	77	218	138	79	24	56
February	11.0	52.6	2467	119	70	189	130	59	18	41
March	10.6	53.6	2977	148	77	226	148	78	24	53
April	13.0	50.0	2132	92	75	166	128	38	12	26
May	13.3	49.6	2117	89	77	166	131	35	11	24
June	12.8	49.5	2539	108	75	183	170	13	6	7
July	14.6	55.0	3667	172	77	249	221	28	14	14
August	14.2	54.1	5745	266	77	343	331	12	11	1
September	16.2	51.3	4299	175	75	250	215	35	11	23
October	15.2	50.5	6009	246	77	323	220	103	28	75
November	12.1	53.0	3006	142	75	217	157	60	17	42
December	9.7	55.1	5434	286	77	363	234	130	39	90
Annual	12.8	52.5	43294	1995	909	2903	2224	679	216	463

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Hydro

Table 18: Domestic Hot Water Data for House # 7

House # 7 Domestic Hot Water Data										
A	B	C	D	E	F	G	H	I	J	K
Month	Average Water Heater Inlet Temperature (degrees Celsius)	Average Water Heater Outlet Temperature (degrees Celsius)	Hot Water Usage (litres)	Energy delivered to water usage (kWh)	Calculated Stand-By Loss (kWh)	Total Hot Water Energy (kWh) E + F	Hot Water Heater Electricity Usage (kWh)	Energy provided by Desuperheater (kWh) G-H	Electric Energy to Heat Pump (kWh)*	Net energy savings (kWh) I-J
January	13.3	49.0	4694	195	98	293	221	72	24	47
February	13.0	49.5	2936	124	89	213	177	36	12	24
March	12.0	49.0	1932	83	98	181	130	51	17	34
April	11.9	49.6	4424	194	95	289	279	10	3	6
May	13.4	50.6	4540	196	98	294	288	6	2	4
June	17.3	53.0	4349	180	95	275	267	9	2	7
July	15.1	49.4	3785	151	98	249	237	12	8	4
August	15.8	49.6	3928	154	98	252	221	31	2	30
September	16.5	50.0	3358	131	95	226	204	21	7	14
October	16.1	50.0	4859	192	98	290	280	10	3	6
November	15.2	49.2	3788	149	95	244	223	21	8	13
December	13.3	50.9	4629	202	98	300	278	22	9	13
Annual	14.4	50.0	47222	1950	1155	3105	2805	301	98	202

Table 19: Domestic Hot Water Data for House # 8

House # 8 Domestic Hot Water Data										
A	B	C	D	E	F	G	H	I	J	K
Month	Average Water Heater Inlet Temperature (degrees Celsius)	Average Water Heater Outlet Temperature (degrees Celsius)	Hot Water Usage (litres)	Energy delivered to water usage (kWh)	Calculated Stand-By Loss (kWh)	Total Hot Water Energy (kWh) E + F	Hot Water Heater Electricity Usage (kWh)	Energy provided by Desuperheater (kWh) G-H	Electric Energy to Heat Pump (kWh)*	Net energy savings (kWh) I-J
January	16.7	59.1	4851	239	64	303	133	171	96	74
February	16.5	58.7	4720	231	58	289	120	170	91	78
March	15.0	58.4	5336	269	64	333	167	165	97	68
April	14.0	59.0	5146	269	62	331	237	94	61	33
May	13.4	56.5	5391	270	64	334	271	63	40	22
June	13.2	57.9	5929	307	62	369	328	41	7	34
July	15.9	59.3	5855	295	64	359	297	62	18	44
August	15.4	58.7	4685	236	64	300	268	32	7	25
September	15.2	58.2	3917	195	62	257	217	41	27	14
October	16.3	58.7	4988	246	64	310	202	108	72	37
November	15.7	58.0	5080	250	62	312	148	164	102	62
December	15.0	58.8	5830	296	64	360	134	226	129	97
Annual	15.2	58.4	61728	3097	757	3854	2521	1333	748	585

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Table 20: Domestic Hot Water Data for House # 9

House # 9 Domestic Hot Water Data										
A	B	C	D	E	F	G	H	I	J	K
Month	Average Water Heater Inlet Temperature (degrees Celsius)	Average Water Heater Outlet Temperature (degrees Celsius)	Hot Water Usage (litres)	Energy delivered to water usage (kWh)	Calculated Stand-By Loss (kWh)	Total Hot Water Energy (kWh) E + F	Hot Water Heater Electricity Usage (kWh)	Energy provided by Desuperheater (kWh) G-H	Electric Energy to Heat Pump (kWh)*	Net energy savings (kWh) I-J
January	14.1	44.6	3873	137	93	231	92	138	41	98
February	13.9	43.8	2511	87	84	172	64	107	31	76
March	14.2	46.0	4005	148	93	241	115	126	37	89
April	13.2	46.0	4637	176	90	267	171	96	27	69
May	13.4	45.4	4485	167	93	260	193	68	17	50
June	19.0	51.9	4472	171	90	261	207	54	6	48
July	14.3	45.4	4122	149	93	242	170	72	8	64
August	15.5	45.3	3180	110	93	203	150	53	2	51
September	15.5	43.7	3792	124	90	214	153	61	12	49
October	15.0	45.9	4174	149	93	243	159	84	21	64
November	14.4	46.7	3663	137	90	228	116	112	29	83
December	12.3	47.4	3562	145	93	238	101	137	42	96
Annual	14.6	46.0	46476	1700	1101	2800	1692	1109	272	836

Table 21: Domestic Hot Water Data for House # 10

House # 10 Domestic Hot Water Data										
A	B	C	D	E	F	G	H	I	J	K
Month	Average Water Heater Inlet Temperature (degrees Celsius)	Average Water Heater Outlet Temperature (degrees Celsius)	Hot Water Usage (litres)	Energy delivered to water usage (kWh)	Calculated Stand-By Loss (kWh)	Total Hot Water Energy (kWh) E + F	Hot Water Heater Electricity Usage (kWh)	Energy provided by Desuperheater (kWh) G-H	Electric Energy to Heat Pump (kWh)*	Net energy savings (kWh) I-J
January	10.5	50.6	4349	202	79	281	70	211	70	141
February	9.4	50.3	4637	220	71	292	84	207	71	136
March	9.0	48.8	4343	200	79	279	136	143	48	96
April	9.0	47.7	5043	226	76	302	239	64	21	43
May	11.0	47.6	5382	229	79	308	293	14	5	9
June	12.8	48.4	4908	203	76	279	267	13	5	8
July	15.8	47.7	1689	63	79	141	119	22	6	16
August	17.3	49.1	4979	184	79	262	231	31	2	28
September	16.5	47.9	4209	153	76	230	199	31	11	20
October	14.6	47.5	4862	186	79	264	210	54	18	36
November	10.4	49.1	5381	242	76	318	173	145	67	78
December	8.9	51.4	5387	265	79	344	4	340	72	268
Annual	12.1	48.8	55169	2352	927	3279	2026	1254	396	879

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Appendix H

Run Hours and Starts Data

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Hydro

Table 22: Heat Pump Annual Run-Hours

House		January	February	March	April	May	June	July	August	September	October	November	December	Totals
1	Total	578	518	392	229	138	126	199	113	105	212	402	399	3,410
	Stage 1	370	260	321	191	135	125	184	112	101	209	364	288	2,660
	Stage 2	208	258	71	38	3	1	15	1	4	3	38	111	750
2		476	438	289	109	23	65	208	80	68	128	283	329	2,497
3		115	266	204	74	9	25	53	23	33	49	171	244	1266
4	Total	394	149	67	75	33	79	150	110	32	123	188	89	1,488
	Stage 1	385	149	67	74	30	52	104	73	22	123	187	88	1,354
	Stage 2	9	0	0	1	3	27	46	36	10	0	1	1	134
5		607	540	358	229	148	54	120	47	44	125	247	512	3,032
6	Total	609	599	567	391	201	80	150	122	160	242	398	618	4,137
	Stage 1	235	189	408	335	199	57	101	64	117	196	290	306	2,498
	Stage 2	375	410	159	56	1	23	49	58	42	46	107	312	1,640
7		392	428	265	153	74	21	92	17	63	117	253	408	2,282
8	Total	660	603	510	270	123	65	186	71	88	270	384	637	3,867
	Stage 1	423	282	393	237	116	61	181	66	86	266	323	394	2,830
	Stage 2	236	321	117	33	8	4	5	4	2	3	61	243	1,037
9		475	491	348	135	65	70	114	29	46	106	236	392	2,507
10		529	494	355	156	58	70	87	34	33	139	338	435	2,728
Average Run Hours		483	453	336	182	87	65	136	65	67	151	290	406	2721
Average Equivalent Full Load Run Hours		413	409	276	140	63	51	107	49	51	111	232	353	2254

Two Stage Heat Pump: First stage provides 50% output capacity of second stage

Two Stage Heat Pump: First stage provides 70% output capacity of second stage. First stage and second stage run hours were not seperated.

Average Equivalent Full Load Run Hours is equal to stage # 1 run hours/percent of full load capacity plus stage # 2 run hours

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Table 23: Heat Pump Run Hours (Heating Mode)

Heat Pump Run Hours (Heating Mode)														
House		January	February	March	April	May	June	July	August	September	October	November	December	Totals
1	Total	578	518	392	210	85	16	0	6	62	203	402	399	2870
	Stage 1	370	260	321	174	82	16	0	6	60	200	364	288	2,140
	Stage 2	208	258	71	36	3	0	0	0	2	3	38	111	730
2		476	438	289	109	19	7	1	6	63	128	283	329	2,148
3		115	266	204	74	47	17	0	0	23	48	171	244	1210
4	Total	394	149	67	75	22	0	0	0	9	123	188	89	1114
	Stage 1	385	149	67	74	20	0	0	0	8	123	187	88	1,101
	Stage 2	9	0	0	1	2	0	0	0	0	0	1	1	14
5		607	540	358	229	144	9	0	0	42	125	247	512	2,815
6	Total	609	599	567	391	201	32	2	12	96	231	398	618	3,757
	Stage 1	235	189	408	335	199	27	2	6	73	188	290	306	2,257
	Stage 2	375	410	159	56	1	6	0	6	24	44	107	312	1,499
7		392	428	265	153	74	4	0	0	60	117	253	408	2,153
8	Total	659	603	510	267	103	3	0	2	76	269	384	637	3515
	Stage 1	423	282	393	234	99	2	0	2	75	266	323	394	2,494
	Stage 2	236	321	117	33	4	1	0	0	2	3	61	243	1,021
9		475	491	348	135	60	7	0	0	36	106	236	392	2,286
10		529	494	355	156	49	5	0	0	33	139	338	435	2,534
Average		483	453	336	180	80	10	0	3	50	149	290	406	2440
Average Equivalent Full Load Run Hours		413	409	276	139	60	8	0	2	39	110	232	353	2041

Table 24: Heat Pump Run Hours (Cooling Mode)

Heat Pump Run Hours (Cooling Mode)														
House		January	February	March	April	May	June	July	August	September	October	November	December	Totals
1	Total	0	0	0	19	54	110	199	107	43	9	0	0	541
	Stage 1	0	0	0	17	53	110	184	106	41	9	0	0	520
	Stage 2	0	0	0	2	1	1	15	1	1	0	0	0	20
2		0	0	0	0	4	58	207	74	5	0	0	0	348
3		0	0	0	0	0	8	53	23	11	1	0	0	94
4	Total	0	0	0	0	11	79	150	110	23	0	0	0	373
	Stage 1	0	0	0	0	10	52	104	73	14	0	0	0	253
	Stage 2	0	0	0	0	1	27	46	36	10	0	0	0	120
5		0	0	0	0	4	45	120	47	2	0	0	0	218
6	Total	0	0	0	0	0	48	148	110	63	11	0	0	380
	Stage 1	0	0	0	0	0	30	99	57	44	9	0	0	240
	Stage 2	0	0	0	0	0	18	49	53	19	3	0	0	140
7		0	0	0	0	0	17	92	17	3	0	0	0	130
8	Total	0	0	0	3	20	63	186	69	11	0	0	0	352
	Stage 1	0	0	0	3	16	60	181	64	11	0	0	0	336
	Stage 2	0	0	0	0	4	3	5	4	0	0	0	0	16
9		0	0	0	0	5	62	114	29	11	0	0	0	221
10		0	0	0	0	9	65	87	34	0	0	0	0	195
Average		0	0	0	2	11	55	135	62	17	2	0	0	285
Average Equivalent Full Load Run Hours		0	0	0	1	7	43	107	47	12	1	0	0	218

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Table 25: Annual Heat Pump Compressor Starts

House		January	February	March	April	May	June	July	August	September	October	November	December	Totals
1	**Total**	**2027**	**1513**	**1494**	**700**	**684**	**412**	**402**	**262**	**434**	**1,010**	**1,003**	**1,333**	**11,274**
	Heating	2027	1513	1494	625	457	115	0	38	318	971	1,003	1,333	9,894
	Cooling	0	0	0	75	227	297	402	224	116	39	0	0	1,380
2	**Total**	**1600**	**1193**	**1278**	**519**	**165**	**312**	**1,320**	**660**	**509**	**1,025**	**1,611**	**2,468**	**12,660**
	Heating	1600	1193	1278	518	162	59	8	53	503	1,025	1,611	2,468	10,478
	Cooling	0	0	0	1	3	253	1,312	607	6	0	0	0	2,182
3	**Total**	**330**	**805**	**772**	**311**	**206**	**111**	**258**	**114**	**205**	**234**	**773**	**992**	**5,111**
	Heating	330	805	772	311	206	77	0	0	154	232	773	992	4,652
	Cooling	0	0	0	0	0	34	258	114	51	2	0	0	459
4	**Total**	**1263**	**780**	**249**	**302**	**143**	**62**	**169**	**129**	**103**	**1,041**	**990**	**326**	**5,557**
	Heating	1263	780	249	302	128	0	0	0	75	1,041	990	326	5,154
	Cooling	0	0	0	0	15	62	169	129	28	0	0	0	403
5	**Total**	**703**	**673**	**1117**	**799**	**701**	**502**	**1,238**	**559**	**294**	**807**	**1,303**	**1,187**	**9,883**
	Heating	703	673	1117	799	661	43	0	0	272	807	1,303	1,187	7,565
	Cooling	0	0	0	0	39	459	1,238	559	22	0	0	0	2,317
6	**Total**	**3129**	**2863**	**3214**	**1831**	**738**	**294**	**227**	**236**	**582**	**827**	**1,686**	**3,723**	**19,350**
	Heating	3129	2863	3214	1831	738	205	7	52	458	802	1,686	3,723	18,708
	Cooling	0	0	0	0	0	89	220	184	124	25	0	0	642
7	**Total**	**1592**	**1253**	**1381**	**1008**	**591**	**209**	**885**	**213**	**611**	**1,224**	**1,401**	**1,760**	**12,128**
	Heating	1592	1253	1381	1008	591	28	0	0	570	1,224	1,401	1,760	10,808
	Cooling	0	0	0	0	0	181	885	213	41	0	0	0	1,320
8	**Total**	**1612**	**1351**	**913**	**412**	**201**	**222**	**457**	**226**	**176**	**366**	**644**	**1,391**	**7,971**
	Heating	1612	1351	913	393	130	7	0	6	129	355	644	1,391	6,931
	Cooling	0	0	0	19	71	215	457	220	47	11	0	0	1,040
9	**Total**	**1044**	**807**	**1066**	**447**	**344**	**259**	**359**	**179**	**293**	**722**	**1,193**	**1,322**	**8,035**
	Heating	1044	807	1066	447	339	46	0	0	256	722	1,193	1,322	7,242
	Cooling	0	0	0	0	5	213	359	179	37	0	0	0	793
10	**Total**	**1649**	**1319**	**1867**	**949**	**516**	**257**	**205**	**65**	**357**	**1,343**	**2,004**	**2,034**	**12,565**
	Heating	1649	1319	1867	949	502	59	0	0	357	1,343	2,004	2,034	12,083
	Cooling	0	0	0	0	14	197	205	65	0	0	0	0	481
verage Number of Starts		**1,495**	**1,256**	**1,335**	**728**	**429**	**264**	**552**	**264**	**356**	**860**	**1,261**	**1,654**	**10,453**

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November 2013

Appendix I

Entering Fluid Temperature Data

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Hydro

Table 26: Average Entering Fluid Temperature (Heating Mode)

Monthly Average Entering Fluid Temperature Heating (Fahrenheit)													
House	January	February	March	April	May	June	July	August	September	October	November	December	Weighted Average
1	44.3	44.3	44.4	44.3	44.8	N/A	N/A	N/A	46.3	45.8	45.1	43.4	44.1
2	32.0	32.0	32.7	33.7	46.9	57.6	67.5	61.1	53.8	46.5	38.9	32.9	35.1
3	32.1	31.2	31.1	32.1	32.7	35.1	N/A	N/A	54.8	50.3	42.3	34.3	34.6
4	36.7	38.8	39.2	38.4	42.5	N/A	N/A	N/A	48.8	44.8	41.7	40.6	39.4
5	35.7	34.5	35.8	36.6	38.3	49.9	N/A	N/A	54.0	48.2	45.6	37.5	37.7
6	31.8	31.1	31.2	31.5	32.3	35.5	43.5	51.7	50.3	46.3	43.1	36.1	34.7
7	34.1	31.0	35.0	37.5	40.6	45.2	N/A	N/A	46.5	43.8	39.3	33.5	35.4
8	29.6	27.0	29.3	30.6	34.7	36.7	N/A	45.6	41.1	38.7	34.0	30.2	30.9
9	36.4	33.5	34.6	36.0	43.4	46.4	N/A	N/A	56.8	53.5	50.1	37.8	38.5
10	31.9	29.9	32.8	34.0	39.8	42.8	N/A	N/A	47.7	44.2	40.4	34.3	34.4

Table 27: Average Entering Fluid Temperature (Cooling Mode)

Monthly Average Entering Fluid Temperature Cooling (Fahrenheit)													
House	January	February	March	April	May	June	July	August	September	October	November	December	Weighted Average
1	48.5	51.0	N/A	44.7	45.2	45.5	45.6	46.7	47.1	47.7	N/A	N/A	44.0
2	N/A	N/A	N/A	37.7	41.2	60.9	70.7	69.1	58.2	N/A	N/A	N/A	68.3
3	33.4	N/A	N/A	34.7	N/A	39.1	46.6	54.2	56.9	54.6	44.7	N/A	49.0
4	40.9	43.8	42.5	37.9	48.8	53.0	57.0	58.0	56.7	54.2	49.8	47.9	56.1
5	N/A	N/A	42.9	47.6	N/A	51.7	54.9	56.1	58.3	N/A	48.9	N/A	55.1
6	35.2	N/A	32.7	33.5	36.4	38.6	47.5	53.1	52.5	49.9	N/A	N/A	49.0
7	N/A	N/A	N/A	N/A	N/A	47.6	54.0	54.8	52.4	N/A	N/A	N/A	53.2
8	32.2	29.3	31.2	34.2	41.1	44.6	49.9	50.0	47.8	40.7	N/A	N/A	48.2
9	48.3	N/A	N/A	N/A	41.5	50.3	56.6	59.0	59.8	59.9	N/A	N/A	54.9
10	N/A	N/A	N/A	50.9	46.4	52.0	57.5	60.0	N/A	48.9	N/A	N/A	55.6

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Table 28: Minimum/Maximum Entering Fluid Temperature

	House									
Entering Fluid Temperature (Fahrenheit)	1*	2	3	4	5	6	7	8	9	10
Minimum (Heating)	42.0	29.2	29.0	32.1	33.3	30.5	27.2	24.1	32.3	27.4
Maximum (Cooling)	57.0	88.5	73.4	84.4	66.7	74.5	80.3	66.9	72	83.1

* House 1 is an open system (well to well)

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REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Page No.: page 32

PREAMBLE: "One form of renewable energy being explored in Manitoba is wind. As noted in the Manitoba Clean Energy Strategy (Manitoba 2012, p.29) "Manitoba's 1,000 MWs of new wind will add almost 3,000 gWhs of dependable energy to the system – a substantial contribution. Economically, developing these 1,000 MWs will generate more than $2 billion in new investment, and $400 million in lifetime revenues to rural communities." Despite the noted benefits of wind, section 7.2.4 of the NFAT discusses wind power for three pages and then simply stops. No proposal for encouraging or developing future wind power is provided. Instead, the discussion of wind power focuses on the following critique of wind (Manitoba Hydro 2013, C.7 p.32): "Wind power cannot be reliably controlled due to fluctuations in wind speed; because of its intermittency wind power alone cannot be relied upon to produce electricity when needed. Other issues typically associated with a wind resource include extremes of wind speed (too low or too high), extreme wind gusts, extreme wind shear, and extreme wind turbulence, as well as lack of wind for periods of time. To accommodate a wind resource, other dispatchable resources that have fast energy ramp-up times such as hydro-electric and natural gas-fired generation are required to back-up wind generation when wind energy production is reduced or not available." Given that hydroelectricity currently provides 96 percent of the electricity in Manitoba, it appears reasonable to assume Manitoba has sufficient hydroelectric means of accommodating the intermittency of wind. To this end, the Manitoba Clean Energy Strategy (p.16) observes: "another Manitoba advantage – the large storage capability of our system's reservoirs – an asset which new hydro and new wind also need as they are further developed. The province has also, traditionally, shared these storage and support services with neighbouring utilities, helping the regional grid to run smoothly and supporting wind development in the US. At the same time, Manitoba's first priority moving forward is to use these assets to ensure the development of made-in-Manitoba new hydro and new wind, thus maximizing economic benefits for Manitoba and strengthening its energy security." Ultimately, it is difficult to understand Manitoba Hydro's decision to not pursue further wind potential, especially given the modular nature of wind turbines, that allow for expansion as needed within a short lead time."

QUESTION:

"Please describe the potential for using Manitoba's large hydro storage capacity to support further wind expansion and provide a preliminary assessment of the potential for wind energy to meet a portion of electricity demand in the province over the planning period. "

RESPONSE:

Manitoba Hydro included a Wind/Gas plan as one of the fifteen development plans described and selected for detailed analysis in Chapter 8 – Determination and Description of Development Plans. Specifically, the Wind/Gas plan includes wind generation starting in 2022/23 and supported by natural gas-fired generation starting in 2025/26, and is described in a paragraph on page 15 of Chapter 8.

Supply and Demand Tables for the Wind/Gas plan are provided on pages 56-59 of Appendix 4.2 of the Application. The New Wind line on page 59 of Appendix 4.2 shows that 5,754 GWh of dependable wind generation energy would be installed in this plan by 2047/48. As indicated in Figure 8.1 of Chapter 8, the Wind/Gas plan has a nominal wind capacity of 1,775 MW-significantly greater than 1,000 MW of wind mentioned in the Manitoba Clean Energy Strategy.

The analysis of the Wind/Gas plan inherently assumes optimization with Manitoba Hydro's existing assets, including the use of long term hydro storage capacity. As also indicated page 59 of Appendix 4.2, the 5,754 GWh of dependable wind energy would represent about 14% of the Manitoba Net Load 40,397 GWh of in 2047/48.

The Wind/Gas plan provided in the application is an assessment of the potential for wind energy to meet a portion of electricity demand in the province over the planning period. As indicated in Figure 9.2 of Chapter 9 – Economic Evaluations - Reference Scenario, the Wind/Gas plan has an NPV of $775 million less than the All Gas Plan and $2.471 billion ($0.775 billion plus $1.696 billion) less than the Preferred Development Plan.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Page No.: p.32

PREAMBLE: One form of renewable energy being explored in Manitoba is wind. As noted in the Manitoba Clean Energy Strategy (Manitoba 2012, p.29) "Manitoba's 1,000 MWs of new wind will add almost 3,000 gWhs of dependable energy to the system – a substantial contribution. Economically, developing these 1,000 MWs will generate more than $2 billion in new investment, and $400 million in lifetime revenues to rural communities." Despite the noted benefits of wind, section 7.2.4 of the NFAT discusses wind power for three pages and then simply stops. No proposal for encouraging or developing future wind power is provided. Instead, the discussion of wind power focuses on the following critique of wind (Manitoba Hydro 2013, C.7 p.32): "Wind power cannot be reliably controlled due to fluctuations in wind speed; because of its intermittency wind power alone cannot be relied upon to produce electricity when needed. Other issues typically associated with a wind resource include extremes of wind speed (too low or too high), extreme wind gusts, extreme wind shear, and extreme wind turbulence, as well as lack of wind for periods of time. To accommodate a wind resource, other dispatchable resources that have fast energy ramp-up times such as hydro-electric and natural gas-fired generation are required to back-up wind generation when wind energy production is reduced or not available." Given that hydroelectricity currently provides 96 percent of the electricity in Manitoba, it appears reasonable to assume Manitoba has sufficient hydroelectric means of accommodating the intermittency of wind. To this end, the Manitoba Clean Energy Strategy (p.16) observes: "another Manitoba advantage – the large storage capability of our system's reservoirs – an asset which new hydro and new wind also need as they are further developed. The province has also, traditionally, shared these storage and support services with neighbouring utilities, helping the regional grid to run smoothly and supporting wind development in the US. At the same time, Manitoba's first priority moving forward is to use these assets to ensure the development of made-in-Manitoba new hydro and new wind, thus maximizing economic benefits for Manitoba and strengthening its energy security." Ultimately, it is difficult to understand Manitoba Hydro's decision to not pursue further wind potential, especially given the modular nature of wind turbines, that allow for expansion as needed within a short lead time.

QUESTION:

Please incorporate attention to the potential for biomass heating to reduce winter electricity peaks, in the requested preliminary assessment of wind energy potential in Manitoba, with

particular regard to the expressed concern about wind power not providing adequate service in the winter.

RESPONSE:

"Manitoba Hydro's Winter Electrical Peak" typically occurs after extended periods of extreme cold weather. Electric heating load is a contributor to the electrical peak that offers lesser degrees of diversity in its load profile as declining temperatures trend towards a growing system peak. Manitoba Hydro continually assesses and evaluates generation sources that are capable of servicing current and projected future electric heating loads.

Biomass can be used for heating in two ways:

53) Biomass to heat – where the biomass is burned and the energy directly used for heating applications

54) Biomass to electricity- where the biomass is burned in a boiler and the steam is used to power a turbine generator arrangement to produce electricity.

55)

Manitoba's supply of biomass is in the form of agricultural and forestry residues. To date, biomass resources have not been significantly developed in Manitoba. In 2010, Manitoba Hydro commissioned a Biomass Fuel Heating Study in 2010 to further investigate the contribution biomass to heat can make for small and midscale customers in Manitoba. For more information on the Biomass Fuel Heating Study, please see Manitoba Hydro's response to CAC/MH I-226 b).

Through its Power Smart initiatives, Manitoba Hydro's current efforts focus on opportunities for customers to consider district heating networks with biomass heating sources as potential replacements for heating loads that may otherwise be addressed with electric heating. Biomass energy systems that can be utilized for direct heating or combined heat and power configurations that provide both heat and electricity are being assessed.

While biomass to electricity applications are better suited to constant output (baseload) applications, including combined heat and power applications, utility scale biomass to electricity applications are not particularly well suited to providing a service, described as "firming capacity", for an intermittent resource such as wind. The dispatch and cold-start deployment times for a biomass plant can be measured in hours while that of a faster ramping gas turbine can be measured in minutes. Variations in the energy and moisture content of biomass, as well as fuel storage and logistics are challenges to utilizing biomass generation as load or wind following or peaking service. Biomass to electricity applications are limited in their scalability due to fuel transportation costs and logistics. A 15 MW biomass to electricity facility would require about 22 large square bales of straw per hour, or about 15,000 such bales per month.

While at a high level, encouraging pricing trends are being recognized with various renewable energy forms, evaluation of these resources as part of a secondary backup or hybrid supply can be a complex and challenging process. As these resources mature and become more economic, the opportunity to recommend and integrate the appropriate quantity of these resources into a system that will supply the needed reliability to customers without encroaching on firm planned electric supply can be pursued.

REFERENCE: Chapter 1: Introduction; Page No.: p. 13 (Ch.1) and p. 16 (Ch. 13 Table 13.1) attachment of file located in technical responses

PREAMBLE: "In the NFAT Terms of Reference, Manitoba Hydro is required to ensure "the needs for Hydro's Plan are thoroughly justified, and sound, its timing is warranted, and the factors that Hydro is relying upon to prove its needs are complete, reasonable and accurate" (p. 2).

To do so, the PUB was asked to consider "[t]he alignment of the Plan to Manitoba's Clean Energy Strategy and the Principles of Sustainable Development as outlined in The Sustainable Development Act" (TOR p. 2).

In response to the terms of reference, Manitoba Hydro noted in the NFAT (Executive Summary, p. 4) that it "recognizes the need for sustainability in all aspects of its operations. Economic, environmental and societal decision criteria are applied in the assessment of major projects and plans, including public and stakeholder consultation" (emphasis added). Further on in Chapter 1, Manitoba Hydro provides its decision criteria, which are as follows (Manitoba Hydro 2013, Ch. 1 p. 13):

• "Economics (e.g. comparative NPV evaluation)

• Domestic electricity prices, including broader financial criteria Environmental impacts, both biophysical and socio-cultural

• Affected community acceptance and support

• Public and political stakeholder acceptance and support • Risks and uncertainties

• Provincial and societal benefits

• System reliability and energy security." The list is helpful insofar as it describes the areas of interest for Manitoba Hydro. At the same time, the list presents topics, not criteria. A criterion is defined by the Oxford English Dictionary as "a principle or standard by which something may be judged or decided". One possible set of sustainability criteria that were designed more specifically for the Keeyask project but are more broadly relevant is provided in Section 4 of (Gaudreau et al. 2013) (attached). The criteria proposed in Section 4 may help guide Manitoba Hydro develop its own criteria set, if such a set is not currently available. References Gaudreau, K., et al. (2013). Draft Framework for Sustainability-based Assessment for the Keeyask Hydro Project, Consumers Association of Canada - Manitoba Branch. Manitoba Hydro (2013). NFAT (Needs For and Alternatives To) Business Case Submission Manitoba Hydro."

QUESTION:

Please provide the set of criteria that Manitoba Hydro used for its decision-making process leading to the NFAT submission, including the identification, specification and comparative evaluation of alternatives.

RESPONSE:

Response to CAC/MH I-0228 (a) and (b).

This response utilizes the Table 13.1 framework from the Multiple Accounts Analysis. This framework was developed jointly by the consultant and Manitoba Hydro and reflects the decision factors being utilized by Manitoba Hydro for its development plans.

There are three types of criteria considered for the development plan decision making:

- Quantitative criteria which must be met (i.e. 12 % Capacity Reserve, Dependable Energy Criterion, including the Import Energy Constraints as described in Chapter 4, Section 4.3.1)
- Quantitative criteria which are used to screen out uneconomic options and to compare plans with each other, using judgment to implicitly determine weightings (e.g. NPV of plans, financial targets, transfers to government, employment, GHGs)
- Qualitative criteria which are used to compare plans with each other, using judgment to implicitly determine weightings (e.g. nature and extent of residual biophysical impacts, nature and extent of residual community socio-economic impacts, use of renewable resources)

The identification, specification and comparative evaluation of alternatives based on these criteria are described extensively in the submission. In Chapter 13 these criteria are considered in an integrated multiple account framework, indicating the net advantages and trade-offs among the different plans.

1 **MANITOBA HYDRO CRITERIA CONSIDERED IN DEVELOPMENT PLAN DECISIONS**

2 **(FOCUSING ON GENERATION RATHER THAN TRANSMISSION OR DISTRIBUTION)**

Account	Purpose	Analysis	Criteria or Indicators
Market Valuation (Economics)	Net benefit to Manitoba Hydro (domestic customers and project partners)	Incremental revenues from surplus sales less incremental capital and O&M expenditures.	Net Present Value of export revenues net of imports, fuel cost, O&M, taxes, capital costs, etc. Comparison of plans relative to lowest capital cost plan. (i.e. incremental NPV resulting from incremental capital investment) Plans evaluated at MH real WACC for MH economic analysis and at weighted average social opportunity cost of capital for benefit-cost analysis; risks evaluated with probabilistic scenarios, sensitivities and stress tests. NPV of competing plans to lowest capital cost plan must be positive for reference scenario unless intangible benefits are significant enough (e.g. dam safety).
Manitoba Hydro Customer	Consequences for customers in short to medium and long term.	Rate increases required to recover costs and meet MH financial targets. Financial targets Other financial guidelines Generation Planning criteria Energy security System reliability	Average annual and cumulative rate increases over the planning period. Minimum debt/equity ratio of 75:25 Maintain an Interest coverage ratio greater than 1.20 Maintain a capital coverage ratio greater than 1.20 Note: Financial targets may not be achieved during years of major investment in the generation and transmission system Retained earnings levels sufficient to absorb adverse financial effects of corporate risks to minimize or defer the need for rate increases 12 % capacity reserve Dependable Energy including Import Energy Constraints Emergency drought energy available if drought worse than planned for occurs Load carrying capability utilizing 0.1 days/year LOLE and cost of expected unserved load.
Manitoba Government	Net benefit to taxpayers.	Incremental government net revenues. Amount of additional Manitoba Hydro debt guarantee.	Present value of incremental revenues to government, net of incremental costs Debt guarantee and borrowing by MH.
Manitoba Economy	Consequences for the economy.	Employment generated and incremental income earned.	Present value of incremental income.
Environment	Consequences for emissions and natural and bio-physical effects.	Impact on GHGs in Manitoba and elsewhere. Manitoba CAC(Criteria Air Contaminants) emissions Biophysical impacts.	Present value of social cost of Manitoba GHGs in excess of carbon charge. Impact on global GHGs Present value of CAC damage costs. Nature and extent of residual biophysical impacts. Use of renewable power

Account	Purpose	Analysis	Criteria or Indicators
Social	Consequences for aboriginal and non-aboriginal communities. Other social impacts not addressed elsewhere.	Benefits to project partners. Impacts on affected communities. Value people place on assets remaining at end of planning period.	Nature and significance of partner community benefits Nature and extent of residual community socio-economic impacts. Potential bequest value of remaining assets.
Risk	Nature and significance of key assumptions.	Range of possible consequences. Risk mitigation potential.	Probability distribution of system net revenues and rates. Sensitivities and stress tests

REFERENCE: Chapter 1: Introduction; Page No.: p. 13 (Ch.1) and p. 16 (Ch. 13 Table 13.1)

PREAMBLE: "In the NFAT Terms of Reference, Manitoba Hydro is required to ensure "the needs for Hydro's Plan are thoroughly justified, and sound, its timing is warranted, and the factors that Hydro is relying upon to prove its needs are complete, reasonable and accurate" (p. 2).

To do so, the PUB was asked to consider "[t]he alignment of the Plan to Manitoba's Clean Energy Strategy and the Principles of Sustainable Development as outlined in The Sustainable Development Act" (TOR p. 2).

In response to the terms of reference, Manitoba Hydro noted in the NFAT (Executive Summary, p. 4) that it "recognizes the need for sustainability in all aspects of its operations. Economic, environmental and societal decision criteria are applied in the assessment of major projects and plans, including public and stakeholder consultation" (emphasis added). Further on in Chapter 1, Manitoba Hydro provides its decision criteria, which are as follows (Manitoba Hydro 2013, Ch. 1 p. 13):

• "Economics (e.g. comparative NPV evaluation)

• Domestic electricity prices, including broader financial criteria Environmental impacts, both biophysical and socio-cultural

• Affected community acceptance and support

• Public and political stakeholder acceptance and support • Risks and uncertainties • Provincial and societal benefits

• System reliability and energy security." The list is helpful insofar as it describes the areas of interest for Manitoba Hydro. At the same time, the list presents topics, not criteria. A criterion is defined by the Oxford English Dictionary as "a principle or standard by which something may be judged or decided". One possible set of sustainability criteria that were designed more specifically for the Keeyask project but are more broadly relevant is provided in Section 4 of (Gaudreau et al. 2013) (attached). The criteria proposed in Section 4 may help guide Manitoba Hydro develop its own criteria set, if such a set is not currently available. References Gaudreau, K., et al. (2013).

Draft Framework for Sustainability-based Assessment for the Keeyask Hydro Project, Consumers Association of Canada - Manitoba Branch. Manitoba Hydro (2013). NFAT (Needs For and Alternatives To) Business Case Submission Manitoba Hydro."

QUESTION:

Where possible, please link these criteria to the proposed indicators for the multiple accounts benefit-cost-analysis found in Table 13.1

RESPONSE:

Please see Manitoba Hydro's response to CAC/MH I-228(a).

REFERENCE: Chapter 1: Introduction; Page No.: p. 13 (Ch.1) and p. 16 (Ch. 13 Table 13.1)

PREAMBLE: "In the NFAT Terms of Reference, Manitoba Hydro is required to ensure "the needs for Hydro's Plan are thoroughly justified, and sound, its timing is warranted, and the factors that Hydro is relying upon to prove its needs are complete, reasonable and accurate" (p. 2).

To do so, the PUB was asked to consider "[t]he alignment of the Plan to Manitoba's Clean Energy Strategy and the Principles of Sustainable Development as outlined in The Sustainable Development Act" (TOR p. 2).

In response to the terms of reference, Manitoba Hydro noted in the NFAT (Executive Summary, p. 4) that it "recognizes the need for sustainability in all aspects of its operations. Economic, environmental and societal decision criteria are applied in the assessment of major projects and plans, including public and stakeholder consultation" (emphasis added). Further on in Chapter 1, Manitoba Hydro provides its decision criteria, which are as follows (Manitoba Hydro 2013, Ch. 1 p. 13):

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The criteria proposed in Section 4 may help guide Manitoba Hydro develop its own criteria set, if such a set is not currently available. References Gaudreau, K., et al. (2013). Draft Framework for Sustainability-based Assessment for the Keeyask Hydro Project, Consumers Association of Canada - Manitoba Branch. Manitoba Hydro (2013). NFAT (Needs For and Alternatives To) Business Case Submission Manitoba Hydro."

QUESTION:

Please comment on the sustainability criteria set proposed by Gaudreau et al. (2013) for its relevance for the NFAT assessment, in particular noting which of the criteria (or their clear equivalents) in this set have been applied in the preparation Manitoba Hydro proposals, which criteria have not been applied, and what justification Manitoba Hydro may have for the latter.

RESPONSE:

Manitoba Hydro has followed the NFAT Terms of Reference; the pertinent reference follows:

> The alignment of the Plan and alternatives to Manitoba's Clean Energy Strategy, *The Climate Change and Emissions Reduction Act* and the Principles of Sustainable Development as outlined in *The Sustainable Development Act*.

Manitoba Hydro has applied the principles of sustainable development and utilized the *The Sustainable Development Act* as the defining description. Please refer to NFAT Submission Appendix 14.1.

REFERENCE: Executive Summary; Page No.: p. 16-17 (executive summary)

PREAMBLE: In the NFAT Executive Summary (p. 16-17), Manitoba Hydro describes the screening process for developing the alternative hydro plans. As noted by Manitoba Hydro (Executive Summary, p.16): "The screening process included evaluations of technical, environmental, socio-economic and economic characteristics of each of the options. Based on these evaluations, resources such as solar, nuclear, coal and biomass were screened out as not sufficiently attractive to consider as primary supply contenders in the development plans." While not mentioned in the quote above, both DSM and wind were also excluded from the developments insofar as none of the plans in the MA-BCA included either. Instead, the four development plans discussed in Chapter 13 relate to various combinations of hydro (Keeyask and Conawapa), gas (combined cycle and single cycle) and coal, as well as transmission interconnections with the US. The concern with this process of screening is that individual technologies that may not appear beneficial on their own may in fact have advantages as components in a larger package. For example: • Biomass heating may reduce winter peak loading, and in doing so increase the desirability of wind (which Manitoba Hydro argues is undesirable because wind turbines do not function properly in cold weather). • Hydro may provide a means of addressing the intermittency of wind and solar power supply, thereby increasing the capacity factors and desirability of both. Ultimately, it appears that the approach taken to screening generating, conservation and DSM technologies may be missing positive synergy and may unfairly eliminate some technologies that fare better when assessed as part of a broader power (and energy) system.

QUESTION:

Please provide any documents prepared by or for Manitoba Hydro that consider whether and if so how solar, wind, biomass and DSM options could serve as components of broader power system plan.

RESPONSE:

Appendices 7.1 (Emerging Energy Technology Review, 78 pages), 7.2(Range of Resource Options, 367 pages) and 7.4(Capacity Value of Wind Resources, 4 pages) provide documentation of Manitoba Hydro consideration of solar, wind, biomass and other resources as options considered for inclusion in the development plans. In addition, the main NFAT

submission provides documentation of wind and DSM as options considered for inclusion in the development plans. Power Resource Plans and Emerging Energy Technology reviews of previous years provide similar documentation but the documentation provided with the NFAT submission is the most current documentation.

REFERENCE: Executive Summary; Page No.: p. 16-17 (executive summary)

PREAMBLE: In the NFAT Executive Summary (p. 16-17), Manitoba Hydro describes the screening process for developing the alternative hydro plans. As noted by Manitoba Hydro (Executive Summary, p.16): "The screening process included evaluations of technical, environmental, socio-economic and economic characteristics of each of the options. Based on these evaluations, resources such as solar, nuclear, coal and biomass were screened out as not sufficiently attractive to consider as primary supply contenders in the development plans." While not mentioned in the quote above, both DSM and wind were also excluded from the developments insofar as none of the plans in the MA-BCA included either. Instead, the four development plans discussed in Chapter 13 relate to various combinations of hydro (Keeyask and Conawapa), gas (combined cycle and single cycle) and coal, as well as transmission interconnections with the US. The concern with this process of screening is that individual technologies that may not appear beneficial on their own may in fact have advantages as components in a larger package. For example: • Biomass heating may reduce winter peak loading, and in doing so increase the desirability of wind (which Manitoba Hydro argues is undesirable because wind turbines do not function properly in cold weather). • Hydro may provide a means of addressing the intermittency of wind and solar power supply, thereby increasing the capacity factors and desirability of both. Ultimately, it appears that the approach taken to screening generating, conservation and DSM technologies may be missing positive synergy and may unfairly eliminate some technologies that fare better when assessed as part of a broader power (and energy) system.

QUESTION: Please provide a preliminary analysis of how the potential for each of solar, wind, biomass and DSM to contribute as components are a broader power system plan, taking in to account the potential for positive synergies between or among the various supply and DSM options.

Response:

DSM has a major potential to contribute as a component of a broader development plan. Manitoba Hydro's current DSM plan projects to achieve total electrical savings of 1,552

GWh/year and 490 MW by 2027/28. Combined with efforts to date, total electrical savings will reach 3,113 GW.h/year and 846 MW by 2027/28.

Generally, Manitoba Hydro updates its DSM plan annually with program design, estimated energy savings and costs updated to reflect the most current information. As discussed in the NFAT Submission, Manitoba Hydro will update its current Power Smart Plan, in consultation with government as required by *The Energy Savings Act*, by March 31, 2014. In the process of updating the DSM plan, Manitoba Hydro will take into account the information provided in the DSM market potential study and will evaluate the possibility of a higher level of DSM. The updated Power Smart plan will be included in future Power Resource Plans as part of whichever development plan and pathway is pursued by Manitoba Hydro at the conclusion of the NFAT process.

The DSM plan already contains a customer bio-energy generation program. In the process of updating the DSM plan, Manitoba Hydro will consider customer load displacement based on biomass, solar and other customer self-generation.

As discussed in NFAT Chapter 7 and Appendices 7.1 and 7.2, Manitoba Hydro has been considering utility scale generation utilizing solar, wind and biomass. Utility solar and biomass were screened out as not being cost-competitive. As discussed in NFAT Chapters 9 and 10, wind generation has been evaluated to be uneconomic for the foreseeable future.

Manitoba Hydro does not expect there is potential for appreciable positive synergies between or among the various DSM programs and the utility scale solar, wind and biomass options. Supply options such as biomass and solar are generally not cost-effective if they are not used as a base-load supply option (i.e. biomass options generally do not provide cost-effective peaking capability). This characteristic and the need to be used as a base-load supply option reduces possible synergies for firming other intermittent supply options such as wind and solar.

There are two notable exceptions where there is potential for synergies:

1) In some plans, an increased amount of DSM along with a substantial amount of one or more other resources may benefit one of the competing development plans more than another plan. For example: having increased DSM and wind and biomass may be sufficient to defer new generation substantially in the competing plans. In plans with natural gas generation, the benefits from such deferral of gas generation may be higher than the comparable deferral of hydro generation such as Conawapa because deferral of Conawapa involves a tradeoff between capital deferral and loss of the export revenue while deferral of gas generation involves virtually no such tradeoff. This would tend to benefit more the gas generation plans than the hydro plans and has the potential to involve an appreciable amount of benefit. The effect of this potential for synergies is captured in the 1.5 and 4 times DSM sensitivities that are provided in Chapter 12 of the submission. These sensitivities indicate that such synergies from simultaneous incremental resources from DSM with solar, wind and biomass would not likely alter the economic ranking of the main development plans.

2) In plans which have wind generation being installed when only dependable energy and not capacity are required, there is no clear potential for synergies with DSM (such as wind generation being installed from 2022 to 2025 in Plans 3 and 9). However, in plans which have wind being installed when both dependable energy and capacity are required, there is a potential for DSM capacity rich programs to have synergy benefits with the wind (e.g. wind generation from 2026 onward in Plan 3). The potential arises from the potential for the DSM capacity to displace the need for the simple cycle gas turbines that are utilized in the plan evaluations to meet the winter peak capacity requirements. From the perspective of the economic comparison of capacity from simple cycle gas turbines versus DSM, the DSM capacity to realize such potential economically would need to be from DSM that has a lower winter peak capacity factor than the winter peak capacity factor of the load growth of the period for which the wind generation is being installed. If the load factor associated with the DSM savings is

relatively high, then the system marginal costs used to evaluate such DSM would tend to be dominated by the energy component and tend to be similar to the marginal costs currently utilized to evaluate DSM. The amount of capacity that would be useable for such wind firming would be the incremental capacity associated with the difference between the load growth winter peak capacity factor and the DSM winter peak capacity factor. While such potential synergies are possible, it is judged to be unlikely that this potential is significant. Manitoba Hydro loads generally have less potential for such low winter peak capacity factor DSM.(see note below) Such DSM capacity would need to be available for sustained periods in the winter for the occasions when there is a sustained high peak due to a sustained cold snap (e.g. two week extreme cold period in January.) Secondly, the incremental DSM capacity would need to be lower in cost than the cost of simple cycle gas turbines which constrains the amount of capacity incentive that could be included in the DSM program.

Note: The difficulty with demand response in the Manitoba climate is that the majority of demand response opportunities in the residential and small to medium commercial sectors generally are related to space heating/cooling and water heating (i.e. control of thermostats and hot water tanks). Heat is not optional during the extremely cold weather experienced in Manitoba, so anything that is interrupted must also be replaced, usually within an hour or two, not in 6 or 8 hours, days or weeks. This requirement is further complicated by the fact that the off-peak periods are generally colder than the on-peak periods, so recovery of heat lost during curtailment periods may extend the duration of the peak consumption period. This is exacerbated by the fact that wind and solar are often not available for extended periods of time during the shorter, colder winter days that coincide with Manitoba Hydro system peaks.

This is quite unlike cooling (a heavy contributor to US demand response programs), which is easier to replace in the cooler off-peak periods after being interrupted during the hotter on-peak periods.

During sustained periods of cold weather, demand response opportunities and benefits decline in proportion to the temperature and the duration of the cold weather (i.e. the colder the temperatures and the longer the cold snap, the lower the opportunity for demand response in Manitoba).

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Page No.: p. 55

PREAMBLE: In the terms of reference for the NFAT, Manitoba Hydro was required to compare the macro-environmental impacts of the preferred plan with the macro-environmental impacts of the alternatives. Macro-environmental impacts were defined in PUB Order 92/13 as:

• "A critical analysis of the macro environmental impacts and benefits of Manitoba Hydro's Preferred Development Plan and alternative Plans. Specifically this refers to the collective macro-economic consequences of changes to air, land, water, flora and fauna, including the potential significance of these changes, their equitable distribution within and between present and future generations."

In Chapter 13, Manitoba Hydro argues that there are effectively no important macro-environmental impacts when it notes (Manitoba Hydro 2013, Ch. 13 p.55):

"The economic measure of the cost of any residual impact on environmental resources and attributes is the compensation required by those people who would be adversely affected to willingly accept the impacts and risks. The acceptance and participation of the KCNs in the Joint Keeyask Development Agreement suggests that the cost (for social as well as natural resource and environmental effects as they affect local residents) would be largely internalized in the design, plans and agreements governing the project development. There would be no major **external** cost to take into account" (emphasis included in the original).

Similarly, further on the analysis, Manitoba Hydro notes (Manitoba Hydro 2013, Ch. 13 p.57):

"In summary, while the bio-physical impacts would differ across the different plans, there would not appear to be a major difference in the external costs they give rise to. For the most part the impact-related costs have been internalized with the project designs and plans, and consequently are already reflected in the revenues and expenditures in the market valuation account."

This argument developed by Manitoba Hydro is founded entirely upon the premise that Manitoba Hydro's willingness to pay and the immediately affected communities' willingness to accept compensation can be the foundation for an appropriate means of

measuring the macro-economic consequences of damaging the environment. Nowhere does the PUB definition of macro-environmental impact invite such an interpretation. In adopting this approach Manitoba Hydro has relied on the assumed acceptability (to Manitoba Hydro and the most directly affected communities) of a set of net costs and benefits with biophysical costs traded-off against socio-economic benefits, rather than more directly providing a critical analysis of macro environmental impacts. Given that the proposed project has not been approved, the assumption of trade-off acceptability here is at best premature. Furthermore, this approach taken by Manitoba Hydro cannot easily be considered a critical analysis, which is explicitly what is required by the PUB definition of macro-environmental impact.

Two basic examples to contextualize this concern:

1. The area of flooding for the proposed Keeyask dam is approximately 45km2, whereas Manitoba Hydro notes the land-use impacts of a 320MW combined cycle gas turbine is roughly 2.8 ha (approximately 1/1,600th of the area). It is difficult to understand how these do not lead to different macro-environmental impacts.

2. Manitoba Hydro notes in the NFAT that the First Nations communities in the vicinity of the Keeyask dam are economically vulnerable and suffer much higher levels of unemployment (Manitoba Hydro 2013, Ch.13 p.38). If these communities were more economically prosperous, they would arguably demand higher compensation, indicating both the highly arbitrary nature of this costing approach and that likelihood that it underprices environmental costs by relying on the economic choices of atypically disadvantaged communities.

QUESTION:

Please describe and provide a critical analysis and comparison of the anticipated macro-environmental effects of the preferred development plan and alternative plans, and the macro-economic consequences using a range of valuation methods that do not depend on the atypically disadvantaged circumstances of the most directly affected communities or on assumptions about the acceptability of trade-offs involving socio-economic or other factors not included in the “environment” as described in the PUB order.

RESPONSE:

The multiple account benefit-cost analysis presented in Chapter 13 attempts to identify and assess the full range of consequences of different alternatives to all affected parties. In accordance with well-established principles of benefit-cost analysis the assessment of the significance of different consequences is based on the trade-offs that the affected people or interests would willingly accept – their willingness to pay for benefits or compensation demanded to accept or offset costs. In the multiple account framework, major consequences are presented in disaggregated form and it is explicitly recognized that not all consequences can or arguably should be monetized.

The fact that Keeyask partner communities support the project is important information in the analysis. It indicates that the expected benefits from the partnership and other elements of the project, including the mitigation built into the project design and development plans, offset the resource-related and social costs they expect to incur. In the language of benefit-cost analysis those impacts have been internalized in the project plans and expenditures. That does not mean there will be no environmental consequences, nor does it substitute for the environmental impact assessments that will take place in project-specific reviews. It simply means that for these most directly affected parties the expectation is that the benefits will exceed the costs.

It is recognized in Chapter 13 that there are non-monetized environmental and social effects going beyond the impacts on the directly affected Keeyask partner communities. What was stated was that the available assessments do not suggest there would be major residual effects or trade-offs given the extensive monitoring, mitigation and other measures that are planned, but this will be addressed in the environmental reviews the different projects require.

Some clarification is in order regarding the examples provided in the preamble. The first example refers to the macro-environmental impacts of two different plants and questions how this was addressed in the multiple account evaluation. The NFAT submission recognized that

different projects and different development plans will potentially have different types of impacts, as well as impacts of different magnitude. This information is reflected in appendices 7.2 (Range of Resource Options) and 9.1 (High Level Development Plan Comparison Table). However, the multiple account evaluation considers residual impacts, i.e. impacts after avoidance, mitigation, offsetting measures, and compensation. Furthermore, on September 30, 2013, Manitoba Hydro undertook to provide matrices of macro environmental and socio-economic issues comparing Keeyask, Conawapa, gas turbines and wind generation. The matrices summarize the various components of the PUB's definition of macro environmental and socio-economic as defined in PUB Order 92/13. PUB Order 119/13 added DSM to the resource option to be considered in the matrices, and Manitoba Hydro has chosen to also include transmission project. Please see CAC/MH-231(a).

In the Manitoban and Canadian regulatory context, the multiple account evaluation deems it unlikely that project approval would be granted unless impacts are avoided as feasible, mitigated, offset or compensated and that extensive monitoring and adaptive management approaches are examined in advance to the approval of any individual project. Furthermore, Manitoba Hydro has demonstrated that it goes beyond regulatory requirements to promote projects with positive net benefits and acceptability in those communities most directly affected by its projects. As indicated in the NFAT submission, Keeyask is a good example of such an approach.

Therefore, while it is true that the potential gross impacts may be different depending on the projects that are part of each development plan, the multiple account evaluation expects residual impacts (impacts after avoidance, mitigation, offsetting and compensation), especially on directly affected stakeholders, are not expected to be major.

The second example in the preamble indicates that the communities in the vicinity of the Keeyask dam are economically vulnerable and it suggests such a situation leads to an underpricing of environmental costs. The Keeyask Cree Nations are active and influential

partners in the Keeyask Project. They were professionally represented during negotiations that extended for approximately a decade to establish the partnership and their adverse effects agreements which reflect their past experiences with hydroelectric projects, their priorities and interests, and their worldview. The extensive efforts to avoid and mitigate potential adverse effects and enhance benefits reflect those experiences, interests and worldview. To suggest the Cree Nations' current economic conditions resulted in a willingness to accept lesser compensation and higher environmental costs is, at the very least, not supported by the record of the Keeyask Cree Nations' involvement in the project. Please see CAC/MH-230(d).

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Page No.: p. 55

PREAMBLE: In the terms of reference for the NFAT, Manitoba Hydro was required to compare the macro-environmental impacts of the preferred plan with the macro-environmental impacts of the alternatives. Macro-environmental impacts were defined in PUB Order 92/13 as:

- "A critical analysis of the macro environmental impacts and benefits of Manitoba Hydro's Preferred Development Plan and alternative Plans. Specifically this refers to the collective macro-economic consequences of changes to air, land, water, flora and fauna, including the potential significance of these changes, their equitable distribution within and between present and future generations."

In Chapter 13, Manitoba Hydro argues that there are effectively no important macro-environmental impacts when it notes (Manitoba Hydro 2013, Ch. 13 p.55):

"The economic measure of the cost of any residual impact on environmental resources and attributes is the compensation required by those people who would be adversely affected to willingly accept the impacts and risks. The acceptance and participation of the KCNs in the Joint Keeyask Development Agreement suggests that the cost (for social as well as natural resource and environmental effects as they affect local residents) would be largely internalized in the design, plans and agreements governing the project development. There would be no major **external** cost to take into account" (emphasis included in the original).

Similarly, further on the analysis, Manitoba Hydro notes (Manitoba Hydro 2013, Ch. 13 p.57):

"In summary, while the bio-physical impacts would differ across the different plans, there would not appear to be a major difference in the external costs they give rise to. For the most part the impact-related costs have been internalized with the project designs and plans, and consequently are already reflected in the revenues and expenditures in the market valuation account."

This argument developed by Manitoba Hydro is founded entirely upon the premise that Manitoba Hydro's willingness to pay and the immediately affected communities' willingness to accept compensation can be the foundation for an appropriate means of measuring the macro-economic consequences of damaging the environment. Nowhere does the PUB definition of macro-environmental impact invite such an interpretation. In adopting this approach Manitoba Hydro has relied on the assumed acceptability (to Manitoba Hydro and the most directly affected communities) of a set of net costs and benefits with biophysical costs traded-off against socio-economic benefits, rather than more directly providing a critical analysis of macro environmental impacts. Given that the proposed project has not been approved, the assumption of trade-off acceptability here is at best premature. Furthermore, this approach taken by Manitoba Hydro cannot easily be considered a critical analysis, which is explicitly what is required by the PUB definition of macro-environmental impact.

Two basic examples to contextualize this concern:

1. The area of flooding for the proposed Keeyask dam is approximately 45km2, whereas Manitoba Hydro notes the land-use impacts of a 320MW combined cycle gas turbine is roughly 2.8 ha (approximately 1/1,600th of the area). It is difficult to understand how these do not lead to different macro-environmental impacts.

2. Manitoba Hydro notes in the NFAT that the First Nations communities in the vicinity of the Keeyask dam are economically vulnerable and suffer much higher levels of unemployment (Manitoba Hydro 2013, Ch.13 p.38). If these communities were more economically prosperous, they would arguably demand higher compensation, indicating both the highly arbitrary nature of this costing approach and that likelihood that it underprices environmental costs by relying on the economic choices of atypically disadvantaged communities.

QUESTION:

Please in responding to (a), above, present the overall findings on macro-environmental impact and consequences separately from any discussion of what costs and/or benefits may be considered “internal” or “external”.

RESPONSE:

Please see Manitoba Hydro’s response to CAC/MH I-230(a).

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Page No.: p. 55

PREAMBLE: In the terms of reference for the NFAT, Manitoba Hydro was required to compare the macro-environmental impacts of the preferred plan with the macro-environmental impacts of the alternatives. Macro-environmental impacts were defined in PUB Order 92/13 as:

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Two basic examples to contextualize this concern:

1. The area of flooding for the proposed Keeyask dam is approximately 45km2, whereas Manitoba Hydro notes the land-use impacts of a 320MW combined cycle gas turbine is roughly 2.8 ha (approximately 1/1,600th of the area). It is difficult to understand how these do not lead to different macro-environmental impacts.

2. Manitoba Hydro notes in the NFAT that the First Nations communities in the vicinity of the Keeyask dam are economically vulnerable and suffer much higher levels of unemployment (Manitoba Hydro 2013, Ch.13 p.38). If these communities were more economically prosperous, they would arguably demand higher compensation, indicating both the highly arbitrary nature of this costing approach and that likelihood that it underprices environmental costs by relying on the economic choices of atypically disadvantaged communities.

QUESTION:

Please describe what other costing mechanisms were considered or applied, such as valuing natural capital (Costanza et al. 1997).

RESPONSE:

Multiple account benefit-cost analysis uses well established principles of benefit-cost analysis. Benefit-cost analysis is a mature and accepted methodology which broad purpose is to help social decision making[9].

[9] Boardman A. et al., *Cost-Benefit Analysis: Concepts and Practice*. 3rd. ed., 2006.

No other costing mechanisms such as valuing natural capital have been used in the multiple account benefit-cost analysis. It was not the goal of this analysis either to assign a value to different ecosystems (for example to indicate if the farmer's land is more or less valuable than fisheries or hunting opportunities) or to define whether social effects are more or less valuable than effects on the natural environment. The goal of this particular analysis has been to make explicit the nature of all potential residual effects and not to reduce them to a monetary value unless there is an explicit market (such as in the greenhouse gas emissions).

Please see Manitoba Hydro's response to CAC/MH I-230(a).

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Page No.: p. 55

PREAMBLE: In the terms of reference for the NFAT, Manitoba Hydro was required to compare the macro-environmental impacts of the preferred plan with the macro-environmental impacts of the alternatives. Macro-environmental impacts were defined in PUB Order 92/13 as:

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Similarly, further on the analysis, Manitoba Hydro notes (Manitoba Hydro 2013, Ch. 13 p.57):

"In summary, while the bio-physical impacts would differ across the different plans, there would not appear to be a major difference in the external costs they give rise to. For the most part the impact-related costs have been internalized with the project designs and plans, and consequently are already reflected in the revenues and expenditures in the market valuation account."

This argument developed by Manitoba Hydro is founded entirely upon the premise that Manitoba Hydro's willingness to pay and the immediately affected communities' willingness to accept compensation can be the foundation for an appropriate means of

measuring the macro-economic consequences of damaging the environment. Nowhere does the PUB definition of macro-environmental impact invite such an interpretation. In adopting this approach Manitoba Hydro has relied on the assumed acceptability (to Manitoba Hydro and the most directly affected communities) of a set of net costs and benefits with biophysical costs traded-off against socio-economic benefits, rather than more directly providing a critical analysis of macro environmental impacts. Given that the proposed project has not been approved, the assumption of trade-off acceptability here is at best premature. Furthermore, this approach taken by Manitoba Hydro cannot easily be considered a critical analysis, which is explicitly what is required by the PUB definition of macro-environmental impact.

Two basic examples to contextualize this concern:

1. The area of flooding for the proposed Keeyask dam is approximately 45km2, whereas Manitoba Hydro notes the land-use impacts of a 320MW combined cycle gas turbine is roughly 2.8 ha (approximately 1/1,600th of the area). It is difficult to understand how these do not lead to different macro-environmental impacts.

2. Manitoba Hydro notes in the NFAT that the First Nations communities in the vicinity of the Keeyask dam are economically vulnerable and suffer much higher levels of unemployment (Manitoba Hydro 2013, Ch.13 p.38). If these communities were more economically prosperous, they would arguably demand higher compensation, indicating both the highly arbitrary nature of this costing approach and that likelihood that it underprices environmental costs by relying on the economic choices of atypically disadvantaged communities.

QUESTION:

Please describe the extent to which Manitoba Hydro considered cumulative effects in its assessment of macro-environmental impacts given that cumulative effects are only referenced once in Chapter 13.

RESPONSE:

Manitoba Hydro would like to begin by addressing comments in the preamble.

Regarding suggestions that the Cree were willing to accept greater environment effects:

The Keeyask Cree Nations are active and influential partners in the Keeyask Project. They were professionally represented during negotiations to establish the partnership and their adverse effects agreements which reflect their past experiences with hydroelectric projects, their priorities and interests, and their worldview. The extensive efforts to avoid and mitigate potential adverse effects and enhance benefits reflect those experiences, interests and worldview. To suggest the Cree Nations' current economic conditions resulted in a willingness to accept lesser compensation and higher environmental costs is, at the very least, not supported by the record of the Keeyask Cree Nations' involvement in the project.

Regarding internalized and external costs:

Please see the response to CAC/MH I-230a.

Regarding cumulative effects, as noted in the question:

The MA-BCA draws information about the potential effects of Keeyask and Conawapa from chapter 2 of the NFAT submission. The Keeyask information is drawn from the generation, infrastructure and transmission environmental impact statements, and the Conawapa information is drawn from the on-going environmental studies, the local Cree Nations, and Manitoba Hydro's past experience, notably with the Keeyask Project.

The Keeyask cumulative effects assessment considers the cumulative environmental effects likely to result from the Project in combination with other projects or human activities that have been or will be carried out. From the perspective of the Partnership, the entire Keeyask assessment represents a complete cumulative effects assessment.

The assessment recognizes that the lower Nelson River and adjoining waters, including areas affected by Lake Winnipeg Regulation and Churchill River Diversion, has been and continues to

be an altered environment as a result of the initial diversion and regulation of waters in the early 1970s, as well as on-going regulation and hydroelectric development. The environmental assessment describes how past projects have affected and are continuing to affect the environment. For the purposes of assessing the effects of the Keeyask Project, the Partnership considered how different environmental components have been affected by past developments, as well as the success of mitigation measures applied to address effects both in the study area and elsewhere. This understanding has been used to determine the likely effects of Keeyask and appropriate mitigation measures. In some cases, such as for Lake Sturgeon, proposed mitigation addresses the effects Keeyask and past projects given the already vulnerable state of this species.

In regards to future projects, the Keeyask cumulative effects assessment underscored the importance of coordination between projects and activities, such as Keeyask, Conawapa, Bipole III and Gillam Harmonization and Redevelopment, especially regarding matters such as public safety and worker interaction-and caribou. In these cases, measures have been implemented to respond to effects and to implement monitoring using a coordinated approach that extends across projects.

Regarding a macro-environmental comparison for the NFAT review:

Manitoba Hydro undertook on September 30 to provide matrices of macro environmental and socio-economic issues comparing Keeyask, Conawapa, gas turbines and wind generation. The matrices summarize the various components of the PUB's definitions of macro environmental and socio-economic as defined in PUB Order 92/13. Order 119/13 added DSM to the resource options to be considered in the matrices, and Manitoba Hydro has chosen to also include transmission projects.

Please see the response to CAC/MH I-231a.

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Page No.: 53-54

PREAMBLE: One significant environmental concern of the proposed Keeyask and Conawapa hydro dams relates to the effects of these proposed dam projects on lake sturgeon. As noted by Manitoba Hydro in the NFAT (Manitoba Hydro 2013, Ch.13 p.54):

"The federal government is considering whether to list lake sturgeon in the Nelson River as endangered under the Species at Risk Act (SARA). Manitoba Hydro's planning is based on the assumption that this will not occur, particularly given the stocking and stewardship programs that are being developed and implemented. Were listing under SARA to occur the Keeyask and Conawapa Projects could be delayed or cancelled. If Manitoba Hydro (and in the case of Keeyask the partnership) decided to proceed with the projects, federal permits would be required."

In response to concerns about lake sturgeon, Manitoba Hydro notes in the NFAT filing that (Manitoba Hydro 2013, Ch.13 p.53-54):

"Among the aquatic impacts, there would be some loss of spawning and foraging habitat as well as some blockage of fish passage. Extensive mitigation measures have been planned to minimize and offset these effects. These include plans in construction and for turbine design to minimize impacts; development of new habitat and fish passage; and implementation of a fish stocking program. While some short term declines in fish populations are expected, no declines are expected over the long term, and lake sturgeon populations in the region are expected to increase with the stocking and stewardship programs despite the loss of habitat due to the project."

While the mitigation measures are notable, there are several concerns being raised about the desirability and effectiveness of Manitoba Hydro's approach. While recognizing that the purpose of the NFAT review is not to delve into the EIS, we feel it is necessary to share some concerns raised in the EIS review given that they relate directly to statements made in the NFAT submission. For example, some concerns noted in the information requests for the EIS review process include:

- CAC 0042 remarks on the massive and inexplicable die-offs that occur without warning at Grand Rapids hatchery
- CEC 0031 notes that fish stocking "should be the last mitigation option and not the first"

• MB Wildlands 0052B expresses concern about genetic diversity of Sturgeon in the fish stocking programs

• CEC 0029 expresses concern that stocking without a suitable habitat will not create viable and self-sustaining populations, and the EIS does not suitably describe the habitat

• PFN 0025 notes, among other things, that the stocking program as described in the EIS is overly general, does not actually propose an actual program, and does not provide results of the 2012 trial.

There are several other concerns raised in the IRs, but it should be clear that that the fish stocking program is not a guaranteed success, may not even be a desirable approach, and is insufficiently described to make an accurate assessment of at this point. For these reasons, it is uncertain whether Manitoba Hydro is justified in its claims regarding lake sturgeon in the NFAT submission.

QUESTION:

Please provide a more complete description of the possible effects of, and range of possible consequences for lake sturgeon, recognizing and addressing the concerns raised by interveners in the EIS process.

RESPONSE:

Background

On September 30, 2013 Manitoba Hydro undertook to provide matrices of macro environmental and socio-economic issues comparing Keeyask, Conawapa, gas turbines and wind generation. PUB Order 119/13 added demand side management (DSM) to the resource options to be considered in the matrices, and Manitoba Hydro has chosen to also include transmission projects.

These matrices, which summarize the various components of the PUB's definitions of macro environmental and socio-economic as defined in PUB Order 92/13, are provided in this response to CAC/MH-231a.

The matrices and supporting text draw information from a variety of sources: Manitoba Hydro information, including chapters 2 and 13 and appendices E, 7.2 and 7.3 of the NFAT submission; Round 1 IRs submitted as part of the NFAT review; the Keeyask environmental impact statement and related IRs; the Clean Environment Commission's Bipole III Transmission Project report (as a general proxy for potential effects of the Manitoba-Minnesota Transmission Project and North-South Transmission Upgrade Project); environmental impact statements and monitoring reports for Manitoba wind farms; and information from Health Canada, Environment Canada and the United Stated Environmental Protection Agency. When information from the latter three is used, appropriate citations are provided.

For the NFAT review, it is necessary to identify those critical environmental characteristics that at a macro level may differentiate the environmental and socio-economic effects of hydroelectric, gas turbines, wind generation and DSM, as well as transmission projects. PUB Order 92/13, with five macro environmental and five socio-economic categories, provides the framework for this analysis. For each of those categories, the following are the environmental components or topics considered in the matrix:

- Land: the primary features used for the matrix are the project footprints and the type of area affected.
- Air: the primary feature is greenhouse gas production.
- Water: the primary features considered are water quality and consumption.
- Flora: the primary feature considered is wetlands.
- Fauna: the primary features considered are lake sturgeon, which is receiving additional attention because it has been assessed as "threatened" by the Committee on the Status of Endangered Wildlife in Canada (COSEWIC) and is being considered for listing under the federal Species at Risk Act (SARA); caribou, which includes boreal woodland caribou, has been listed under SARA and The Endangered Species Act (Manitoba); and birds, which may be affected by hydroelectric and wind generation projects as well as transmission lines.

- Employment and Training: In addition to total employment opportunities, this category includes consideration of effects on northern and Aboriginal communities.
- Business Opportunities: Again, this category also considers potential impacts on northern and Aboriginal communities.
- Personal, Family and Community Life: Two issues are considered in this category: i.) impacts from interaction between construction workers and local residents and ii.) impacts on human health from increased mercury levels in fish. Human-health concerns were also identified from sound associated with wind turbines.
- Infrastructure and Services: Proponents and/or contractors generally assume some responsibility for housing construction workers on major projects and may become involved in housing for operational staff.
- Resource Use: Hunting, fishing and gathering are primary resource uses potentially affected by projects in remote wilderness areas, while impacts on agricultural practices are a primary concern in southern Manitoba.

In their focus on critical topics, the matrices do not cover many topics considered in the environmental assessments. Thirty-eight valued environmental component (VECs) and dozens more supporting topics were studied as part of the Keeyask environmental impact assessment, and the Bipole III environmental assessment had even more VECs – 67. The Consumers Association of Canada and Manitoba Hydro agreed to focus the NFAT review to a much smaller number of critical topics, and while there was agreement on several of these, the final list was determined by Manitoba Hydro. In selecting the most critical topics for the NFAT review, the environmental matrix focuses on sturgeon but not other fish species such as walleye or whitefish (whose long-term populations, according to the Partnership's environmental assessment, are expected to increase in the reservoir and remain stable in Stephens Lake) or northern pike (whose populations are expected to remain similar to pre-project conditions). Similarly, the matrix focuses on greenhouses gases but not other air emissions, such as NO_x, SO_x and PM_{10}, which are emitted by gas turbines but are controlled by existing technology within regulatory limits. Water quality is cited as an issue associated with hydroelectric projects,

although the effects, for the most part, can be well managed, and with hydraulic fracturing ('fracking') used in natural gas exploration and production; but the matrices make no mention of water quality associated with transmission, gas turbine and wind projects because the potential effects are much more limited and managed with existing construction practices. The matrices also make no mention of recent public concerns about earthquakes related to fracking. Under infrastructure and services, the socio-economic matrix focuses on housing, for which proponents of large projects accept some measure of responsibility. However, the matrix does not include other services such as transportation, health care and policing for which other agencies take a leading responsibility. By screening out topics such as these, the resulting analysis is intended to assist the PUB discern the major differences in macro environmental and socio-economic effects resulting from the different technologies.

Macro-environmental Comparison of Resource Options

Keeyask 695 MW	Conawapa 1485 MW	Transmission	Gas SCGT:216 MW	Wind 100 MW	DSM
Air					
Greenhouse gases (2.5 tonnes / GW.h)	Greenhouse gases 1.4 tonnes / GW.h	Greenhouse gases (Not calculated; minor or negligible)	Greenhouse gases (SCGT: 764 tonnes / GW.h) (CCGT: 509 tonnes / MW.h)	Greenhouse gases (13 tonnes / MW.h)	Greenhouse gases (Reduction of 1 million tonnes by 2027/28)
Land					
125 km^2 / 695 M (0.2.75 km^2 / MW) 225 m^2 / GW.h	10 - 20 km^2 / 1485 MW (0.005 - 0.01 km^2 / MW) 16 - 32 m^2 / GW.h	M-M Project: - In Manitoba: Early estimate of 12 - 15 km^2 - In Minnesota: Early estimate of 24 km^2 N-S Upgrade Project: Under study	For generating station: 0.03 km^2 / 320 MW (negligible on a per MW basis) Including upstream gas production: 650 – 1070 m^2 / GW.h	Footprint: 0.15 – 0.30 km^2 Total area: 15 – 46 km^2 Footprint: 21 m^2 / GW.h Total area: 6,600 m^2 / GW.h	
Water					
Water quality	Water quality		Water quality and Consumption (Related to exploration and production of natural gas)		Consumption (Consumer savings of 10 billion litres by 2027/28)

Keeyask 695 MW	**Conawapa** 1485 MW	**Transmission**	**Gas** SCGT:216 MW	**Wind** 100 MW	**DSM**
Flora					
Wetlands	Wetlands				
Fauna					
Lake Sturgeon (Long-term benefit)	Lake Sturgeon (Under study)				
Birds	Birds	Birds		Birds and Bats	
Caribou	Caribou	Caribou (North-South Upgrade Project)	Caribou (Effects related to exploration and production of natural gas in Alberta)		

Macro Environmental Effects

Land

- **Keeyask**: The Keeyask Project will require about 125 km^2 of land in the boreal forest. Of that, approximately 50 km^2 is land that will be flooded for the reservoir and converted into aquatic habitat. The remainder is required for the generating station, dams, dykes, transmission lines and related infrastructure such as roads and borrow areas. This area is equivalent to about 290 m^2/GWh.
- **Conawapa**: The Conawapa Project will require over 20 km^2 of land in the boreal forest during construction and slightly less than 10 km^2 during operations. Of that, 5 km^2 is land that will be flooded for the reservoir and converted into aquatic habitat. This operational area is equivalent to about 16 m^2/GWh.
- **Manitoba-Minnesota and Northern Upgrade Transmission Projects**: The route for the Manitoba-Minnesota Transmission Project is not yet confirmed. However, at a preliminary high level, it is estimated it may require approximately 12 to 15 km^2 of land in Manitoba, some of which may be forest and other natural areas and some of which may be agriculture, and 24 km^2 in Minnesota, where this project is referred to as the Great Northern Transmission Line. The North-South Upgrade Project is also in its early stages with the routes and length dependent upon a facility study that is not yet complete. It would occur on lands in the boreal forest, as well as on agricultural land.
- **Gas**: A gas turbine generating station would require approximately 2 to 3 hectares (i.e., 0.02 - 0.03 km^2). This does not include land required for the exploration and production of natural gas in locations such as Alberta, the source of Manitoba Hydro's natural gas. Including land use associated with the upstream extraction and production of natural gas would increase the land use intensity to approximately 650 – 1,070 m^2/GWh, depending upon the efficiency of the station.
- **Wind**: The towers required for a 100 MW wind farm would have a 15 to 30 ha footprint but would be spread over a much larger area to maintain turbine performance (e.g. to manage 'downstream' effects from one tower to the next) and allow for setbacks from residences and other buildings – in the neighbourhood of 15 to 45 km^2 or more for a

100 MW wind farm. Calculations for land use intensity reflect this same broad range, from 21 m^2/GWh for a small footprint to 6,600 m^2/GWh for the broadly affected area.

Air

The Intergovernmental Panel on Climate Change has determined climate warming is unequivocal, human influence on the climate system is clear, and continued emissions of greenhouse gases will cause further warming and changes in all components of the climate system. It further states that limiting climate change will require substantial and sustained reductions of greenhouse gas emissions.[1] Greenhouse emissions are measured in carbon dioxide equivalents (CO_{2e}). The following is based on data from the Pembina Institute's life-cycle greenhouse assessment (Appendix 7.3 of the NFAT submission).

- **Keeyask**: 2.5 tonnes of CO_{2e} per GWh
- **Conawapa**: 1.4 tonnes of CO_{2e} per GWh
- **Manitoba-Minnesota and Northern Upgrade Transmission Projects**: Minor based on preliminary order of magnitude estimate
- **Gas**: 509 tonnes of CO_{2e} per GWh for CCGT; 764 tonnes of CO_{2e} per GWh for SCGT
- **Wind**: 13 tonnes of CO_{2e} per GWh

As well, Manitoba Hydro has estimated its electric Power Smart programs will reduce greenhouse gas emissions by over 1 million tonnes between 2013/14 and 2027/28.

Water

Water quality is fundamental to the health of aquatic life. Federal and provincial guidelines and objectives and guidelines assist in defining water quality conditions. Water consumption can also be a concern, especially when natural gas is produced using a technique known as hydraulic fracturing ('fracking').

[1] IPCC WGI AR5 (2013). Summary for Policymakers: Twelfth Session of Working Group 1.

- **Keeyask**: The main effect to water quality during construction will be increases in sediment, i.e. total suspended solids (TSS). With the implementation of protocols to manage sediment during in-stream construction, increases in TSS will generally be measurable near the project. For a few months during two years of construction, small increases in TSS will extend past the Kettle Generating Station. Increases in TSS are not expected to be large enough to harm plants or animals living in the water. Other potential effects to water quality caused by construction activities such as runoff and accidental spills are managed with standard construction practices, and effluents from wastewater will be treated according to a provincial licence.

  Water quality in newly flooded areas will be affected during the initial years of operation, and then are expected to diminish over the next 10 to 15 years. Overall water quality will be suitable for aquatic life in the main part of the reservoir and downstream of Keeyask, and will be suitable at most locations during most times of the years in the flooded area.

  The effectiveness of the environmental protection plan will be monitored, and additional measures (i.e. adaptive management) can be implemented if necessary. Participants in the environmental and NFAT reviews have expressed concern about potential changes to water quality that could affect aquatic life, such as changes in nutrients and particularly the introduction of sediment.

  The Partnership's analysis of the existing environment; the appropriateness of its mitigation, monitoring and adaptive management plans; and conclusions regarding water quality are the subject of review in the environmental review processes.
- **Conawapa**: Although the environmental assessment is still not complete, Conawapa is expected to have minimal effects on water quality, most of which would occur during construction.

- **Manitoba-Minnesota and Northern Upgrade Transmission Projects**: With established construction methods, most notably at water crossings, water quality is not expected to be a concern with transmission projects. In its report on the Bipole III Project, the Clean Environment Commission concluded water quality should be protected if protection and mitigation measures are stringently followed.
- **Gas Turbines**: Potential effects to water quality caused by construction activities such as runoff and accidental spills are managed with standard construction practices. However, "upstream" of the gas turbines, concerns about water quality and consumption are associated with the extraction of natural gas, which is used to produce electricity from natural gas turbines. Hydraulic fracturing (i.e. "fracking") is a technique used to produce natural gas from unconventional reservoirs, such as shale, tight sands and coalbeds. It involves the injection of fluids, including large quantities of water, under pressures great enough to fracture the gas-producing formation. The resulting fractures are held open using "proppants," such as fine grains of sand or ceramic beads. While Natural Resources Canada reports that provincial officials in British Columbia, Alberta and Saskatchewan have never had a confirmed case of groundwater contamination caused by fracking, the United States House of Representatives has asked its Environmental Protection Agency[2] to undertake a Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources. Its Progress Report (2012) notes concerns regarding potential effects on the quality of potable water and the large volumes of water required for the fracking process. This study is on-going.

  Gas turbines also consume water, which is covered by provincial licensing requirements.
- **Wind**: Relatively small potential effects to water quality caused by construction activities such as runoff and accidental spills are managed with standard construction practices.

[2] United States Environmental Protection Agency (2012). *Study of the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources: Progress Report.*

- **DSM**: Three residential and commercial programs included in the 2013 – 2016 Power Smart Plan are expected to capture additional water saving benefits for consumers. The Water and Energy Saver Program, Lower Income Energy Efficiency Program and Commercial Kitchen Appliance Program are expected to save consumers 10 billion litres of water between 2013/14 and 2027/08.

Flora

Wetlands convert sunlight into vegetation, create soil, protect shorelines and contribute to biodiversity, and some wetlands provide high quality habitat not otherwise available for some plant and animal species. Some wetland types or specific wetlands are particularly important at the regional, provincial or global scale. Ramsar, the North American Waterfowl Management Plan, Ducks Unlimited and the Manitoba Heritage Marsh Program have identified wetland sites that are globally, nationally or provincially significant.

- **Keeyask**: Approximately 90% of the Keeyask regional study area is wetland. The Keeyask Project is expected to affect slightly over to 80 km^2 of wetland, which is less than 1% of the total wetland area in the regional study area. The Keeyask region contains no sites identified as globally, nationally or provincially significant by Ramsar, the North American Waterfowl Management Plan, Ducks Unlimited and/or the Manitoba Heritage Marsh Program. The Partnership will replace 12 ha of off-system marsh habitat that will be flooded by the project.

Participants in the environmental and NFAT reviews have expressed concern about the characterization of cumulative effects on Nelson River wetlands and the time required to re-establish wetland habitats. The Partnership's analysis of the existing environment; the appropriateness of its mitigation, monitoring and adaptive management plans; and conclusions regarding wetlands are the subject of review in the environmental review process.

- **Conawapa**: While the environmental assessment is currently on-going and no conclusions have been reached, at this time Conawapa's effect on wetlands is expected to be minimal because of its limited footprint.
- **Manitoba-Minnesota and North-South Upgrade Transmission Projects**: With the application of standard construction practices, including the establishment of buffers and the ability to route away from sensitive sites, transmission projects' effects on wetlands would be expected to be minor for the Manitoba-Minnesota Project. The North-South Upgrade Project passes through areas of northern Manitoba which are largely wetlands. Manitoba Hydro will apply standard construction practices, including winter construction and routes that avoid sensitive wetland types to the extent practicable, to manage effects on wetlands.
- **Gas Turbines**: Gas turbines have limited footprints and can be located away from wetlands. Wetlands would not be expected to be a concern. The exploration and production of natural gas would affect wetlands.
- **Wind Generators**: Wind turbines would not be expected to be placed on wetlands.
- **DSM**: Not applicable.

Lake Sturgeon

Lake sturgeon are culturally and spiritually important to the Cree, are a Manitoba heritage species, have been designed as endangered by COSEWIC, and are being considered for listing under the *Species at Risk Act (SARA)*.

- **Keeyask**: Keeyask will affect sturgeon spawning and young-of-year habitat and will block sturgeon movements from Stephens and Gull Lakes, although studies have shown upstream movements from Stephens Lake do not appear to be a life-cycle requirement. To mitigate these effects, the Partnership will develop new sturgeon habitat; undertake an experimental, up-stream fish passage study; install turbines that enable a large percentage of fish to successfully pass downstream; and implement a regional sturgeon stocking program. The effectiveness of the mitigation program will be monitored, and additional measures (i.e. adaptive management) will be implemented if necessary.

Among concerns raised during the review processes, participants have expressed concern that stocking programs, while successful in some areas, have not been proven at hydroelectric projects; all habitat required for sturgeon to fulfill their life cycles may not be available once the project is developed; and the ability of large sturgeon to move past the generating station.

The Partnership's analysis of the existing environment; the appropriateness of its mitigation, monitoring and adaptive management plans; and conclusions regarding sturgeon are the subject of review in the environmental review processes.

- **Conawapa**: Sturgeon-related concerns associated with Conawapa include effects to habitat and blockage of movements. Mitigation will include the creation of new habitat, consideration of fish passage, and a regional stocking program. The Conawapa assessment is also giving special attention to two migrating species, brook trout and cisco. The environmental assessment is on-going at this time.
- **Manitoba-Minnesota and Northern Upgrade Transmission Projects**: Not applicable
- **Gas**: Not applicable
- **Wind**: Not applicable
- **DSM**: Not applicable

Caribou

Caribou are important to the northern ecology and to northern Aboriginal people. Boreal woodland caribou are protected under the federal *Species at Risk Act (SARA)* and *The Endangered Species Act* (Manitoba). Some local Cree identify woodland caribou in the Keeyask region, but federal and provincial regulators have not determined that the caribou resident in the Keeyask area are protected boreal woodland caribou. Manitoba is in the process of updating its caribou range boundaries. Boreal woodland caribou have a low natural population growth rate and are sensitive to habitat and human disturbance. Environment Canada[3] has

[3] Environment Canada, 2012. *Recovery Strategy for Woodland Caribou* (Rangifer tarandus caribou)*, Boreal population, in Canada.*

identified forestry, oil and gas exploration and production, mining and mineral exploration and development, hydroelectric development and tourism as having a negative effect on boreal woodland caribou.

- **Keeyask**: Habitat losses, habitat fragmentation, increased predator access and sensory disturbances from heavy machinery and construction activities such as blasting will affect caribou. Among strategies to mitigate these potential effects, the Partnership has adjusted roads, borrow areas and excavated placement areas to avoid sensitive caribou habitat; will limit some construction activities such as blasting to the extent practicable during the calving season; and will block access trails once they are no longer required (i.e., post-construction). New calving habitat is also expected to be created on new islands in the new reservoir. The effectiveness of the mitigation program will be monitored, and additional measures (i.e., adaptive management) can be implemented if necessary. The Partnership expects the overall effects to caribou to be adverse but regionally acceptable because habitat loss is small compared to its widespread regional availability, predation is not expected to change, and changes to intactness are expected to be small over the caribou's range. The Keeyask Partnership recognizes broader issues related to caribou management go beyond those of individual projects, and is working to develop a process that allows for coordination of its activities with those of others involved in long-term caribou monitoring and management in the region. Participants in the review processes have expressed a number of concerns, including: the accuracy of the Partnership's predictions regarding habitat suitability and loss; the herd affiliation of caribou resident in summer; and cumulative effects. They have also questioned whether the caribou identified by Aboriginal traditional knowledge as woodland caribou would be considered by Environment Canada to be a self-sustaining population. The local Cree are concerned caribou will disappear from the area and not return for a long time. The Partnership's analysis of the existing environment; the appropriateness of its mitigation, monitoring and adaptive management plans; and conclusions regarding caribou are the subject of review in the environmental review process.

- **Conawapa**: As with Keeyask, Manitoba Hydro recognizes broader issues related to caribou management go beyond those of individual projects, and is working as a member of the Keeyask Partnership to develop a process that allows for coordination of its activities with those of others involved in long-term caribou monitoring and management in the region.
- **Manitoba-Minnesota and North-South Upgrade Transmission Projects**: There are no caribou in the area when the Manitoba-Minnesota Project would be located. However, boreal woodland caribou exist in areas where the North-South Transmission Upgrade Project may be located. The potential effects on caribou would be included in the environmental assessment, along with methods to manage and mitigate those effects. In its Bipole III report, the Clean Environment Commission expressed concern about the marginal status of many caribou herds and was encouraged by a list of Manitoba Hydro mitigation measures. The commission added that additional mitigation measures may be required if monitoring indicated a continued adverse effect of the project on caribou. In supporting Manitoba Hydro's application for the Bipole III Environment Act licence, the commission set out several recommendations related to on-going caribou monitoring and management. These resulted in licence conditions to which Manitoba Hydro will adhere.
- **Gas Turbines**: A gas-turbine generating station located near a load centre in southern Manitoba would not affect caribou. However, the COSEWIC Assessment and Update Status Report on Woodland Caribou[4] (2002) noted much of the species' range includes areas where natural gas is also extracted. COSEWIC further noted the government of Alberta (the source of Manitoba Hydro's natural gas) has guidelines regarding development activities on caribou ranges.
- **Wind Generation**: Not applicable.
- **DSM**: Not applicable.

[4] Committee on the Status of Endangered Wildlife in Canada. 2002. *COSEWIC Assessment and Update Status Report on the Woodland Caribou – Rangifer tarandus caribou.* Environment Canada, Ottawa.

Birds and Bats

Some species of birds are an important source of game for Aboriginal people, both as a food source and cultural activity. Migratory species are protected under the federal *Migratory Bird Convention Act* and some species are protected under the federal *Species at Risk Act* and/or *The Endangered Species at Risk Act* (Manitoba).

- **Keeyask**: Approximately 185 bird species potentially breed within or migrate through the Keeyask regional study area. Of these, 150 migrate to southern areas for winter. Eight at-risk species were observed in the regional study area, including three listed under SARA. A single bat was observed early in the period of studies. No nationally, regionally, or locally important migratory bird habitat, as designated by the Canadian Wildlife Service and/or Bird Studies Canada, occurs within the regional study area. Construction activities will disturb birds close to the project site, habitats will be lost and changed, and increased access could result in larger harvests. Among measures to mitigate these effects, clearing and blasting will be restricted to the extent practicable during the bird-breeding season, buffers will be established, and some new habitat, including nesting islands and platforms, will be created. The effectiveness of the mitigation program will be monitored, and additional measures (i.e. adaptive management) can be implemented if necessary. Participants in the review processes have raised a number of concerns, including the need for more details about the reduction of construction activities during the breeding season, declines in the availability of waterfowl for hunting, and the need for more details about the monitoring program.

The Partnership expects effects on birds will be adverse but regionally acceptable because of the mitigation programs and the widespread availability of the type of habitats affected by the project. The Partnership's analysis of the existing environment; the appropriateness of its mitigation, monitoring and adaptive management plans; and conclusions regarding birds are the subject of review in the environmental review process.

- **Conawapa**: While some specific species may differ between Conawapa and Keeyask, Manitoba Hydro expects to take a similar approach to mitigating effects on birds, with a similarly positive result.
- **Transmission Projects**: The Clean Environment Commission's findings about birds in its Bipole III report may be informative regarding the Manitoba-Minnesota and the North-South Upgrade projects. Of 400 bird species identified in Manitoba, 371 have ranges within the Bipole III study area, and 218 of those are seasonal breeders. With Manitoba Hydro's mitigation and monitoring measures, the Commission concluded Bipole III poses little risk to bird populations beyond a relatively small amount of habitat loss and bird-wire collisions.
- **Wind Generation**: Effects on birds and bats were identified as concerns in the EISs of wind farms licenses in Manitoba. The licences for both projects required monitoring of these effects. According to data submitted to Manitoba Conservation and Water, a 2006 study at the St. Leon Project identified an annual bird mortality of four birds per turbine and no evidence of bat mortality. However, outside the study 13 bats died over a short duration. A 2011 – 2012 study at the St. Joseph Project identified bird mortality of two birds per turbine and bat mortality of 22.5 per turbine. The studies concluded these rates are low to moderate.
- **DSM**: Not applicable.

Socio-economic Comparison of Resource Options

Keeyask 695 MW	Conawapa 1485 MW	Transmission	Gas SCGT:216 MW CCGT: 320 MW	Wind 100 MW	DSM
Employment (construction) (Estimates are in person years)					
Northern / Aboriginal: 500 – 1700 person Manitoba (includes Northern / Aboriginal): 4300 direct; 3400 indirect Canada: 15,500 Total: 23,300	Aboriginal / Northern: more than Keeyask but not yet estimated Manitoba: 5000 direct; 4100 indirect Canada: 21,000 Total: 30,100	Total: not yet estimated Northern Aboriginal: not yet estimated	SSGT total in Manitoba: 116 CCGT total in Manitoba: 320	Total in Manitoba: 50 - 120	
Employment (operations) (Estimates are in full-time equivalent positions)					
Total: 50 Northern Aboriginal: Not estimated, but expected to be among the 50 (45% of Manitoba Hydro's existing northern workforce is Aboriginal) Note: Minimum of 182 jobs in existing operations targeted for KCN Members	Total: 60 Northern Aboriginal: Not estimated, but expected to be among the 60 (45% of Manitoba Hydro's existing northern workforce is Aboriginal)	Total: not yet estimated Northern / Aboriginal: not estimated	SSGT total: 52 CCGT total: 94 Northern / Aboriginal: nil	Total: 6 - 12 Northern / Aboriginal: nil	Total: not estimated Northern / Aboriginal: not estimated

Keeyask 695 MW	Conawapa 1485 MW	Transmission	Gas SCGT:216 MW CCGT: 320 MW	Wind 100 MW	DSM
Local Business Opportunities					
Northern Aboriginal: $200,000,000 Other suppliers and subcontractors	Northern Aboriginal: Not yet determined Other suppliers and subcontractors	Northern Aboriginal: Clearing contract Other suppliers and subcontractors	Northern Aboriginal: nil Other suppliers and subcontractors	Northern Aboriginal: nil Other suppliers and subcontractors, including contracts with landowners	2,300 registered contractors
Infrastructure and Services					
Housing:	Housing:				Housing: Improvements to existing housing stock, including northern and First Nations
Personal, Family and Community Life					
Worker interaction with local residents Mercury	Worker interaction with local residents		See “Water Quality” in the macro environmental matrix	Noise	
Resource Use					
Domestic hunting, fishing and gathering	Domestic hunting, fishing and gathering	Domestic hunting, fishing and gathering Agricultural equipment / practices	Domestic hunting, fishing and gathering (Effect related to exploration and production of natural gas)		

Socio-economic Effects

Training and Employment

The matrix provides data regarding direct jobs that will be created by the projects, along with available data on indirect jobs from the Keeyask and Conawapa projects. For an analysis of the net benefits of employment between the preferred and alternative development plans, please see section 13.3.4 of the NFAT submission (Integrated Comparisons of Development Plans – Multiple Accounts Analysis).

- **Keeyask**: The Keeyask Project would provide extensive employment opportunities in northern Manitoba and throughout Manitoba and Canad. To enhance employment opportunities, 2670 northern Aboriginals received training in a variety of trades and service occupations through the Hydro Northern Training and Employment Initiative. Under the collective bargaining agreement for construction of the project, northern Aboriginal and other northern Manitobans will be given hiring preferences. An Advisory Group on Employment will monitor employment issues during the construction phase. Among concerns raised by participants in the review processes, the Manitoba Metis Federation5 is concerned about the lack of Metis-specific data and programs. Other participants expressed concerns related to 'boom-and-bust dynamics' associated with employment on major construction projects, the potential for employment incomes to lead to 'destructive ends', and inequity of anticipated incomes among members of First Nation communities. The Partnership's analysis of the existing environment; the appropriateness of its mitigation, monitoring and adaptive management plans; and conclusions regarding employment and training are the subject of review in the environmental review process.
- **Conawapa**: Aboriginal and other northern residents will benefit from past experience with the Hydro Northern Training and Employment Initiative and preferences under the collective bargaining agreement. If construction of Conawapa follows within a few years

[5] The MMF and Manitoba Hydro, acting on behalf of the Keeyask Partnership, have reached an agreement for an MMF-led Traditional Land Use and Knowledge Study, Socio-economic Impact Assessment and historical narrative for the Keeyask region. Please see MMF-MH I-0001(b) and MMF-MH I-0002 for more information regarding Metis-related information.

of Keeyask, many should be able to benefit from their Keeyask experience to gain employment at Conawapa.

- **Manitoba-Minnesota and North-South Upgrade Transmission Projects**: Employment opportunities have not yet been calculated. Short-term opportunities will exist for northern and Aboriginal workers.
- **Gas**: Since gas turbines would be developed on private land in southern Manitoba, northern and Aboriginal people would not be expected to receive training and employment preferences on a gas turbine project. The exploration and production of natural gas employs many people elsewhere in Canada.
- **Wind**: Since wind farms would likely be developed on private land in southern Manitoba, northern and Aboriginal people would not be expected to receive training and employment preferences. Preferences for southern Aboriginal people may be more likely if towers were placed on reserve or Crown lands. As well, the environmental impact statements for wind projects developed in Manitoba did not indicate any preference for southern Aboriginal people.
- **DSM**: With 2300 Power Smart registered contractors, many people are employed in the private sector to deliver Power Smart-related programs, but the total number is not tracked. The following are a few examples:
    - A contractor associated with Refrigerator Retirement Program established a warehouse and de-manufacturing plant with 17 employees. Its call centre services were contracted to another local firm.
    - A contractor with the Water and Energy Saver Program employs 23 people.
    - Northern and Aboriginal people are among those gaining employment and training opportunities through the First Nations Power Smart Program, in which work is performed by local community members.
    - Twenty-eight members of two First Nations completed training in 2013 to install geothermal heat pump systems and nine have gone on to become certified installers. These people may be employed by First Nations installing the systems through a partnership between Aki Energy, a non-profit social enterprise group,

and the Power Smart Community Geothermal Program. The installations are financed through Manitoba Hydro's PAYS program.

Business Opportunities

While general civil contracts would be expected to be awarded to companies with the resources and expertise required for large energy projects, local businesses may be able to provide services and materials to the projects.

- **Keeyask**: The local Keeyask Cree Nations (which are receiving opportunities to invest in the project with favourable financing terms) have negotiated a number of business contracts for the construction of the Keeyask Infrastructure Project, and several more will be negotiated for the generation project. Total value of the contracts for the four Cree Nations will total over $200 million, which is substantial for these communities with limited previous experience. These contracts should also assist these communities in developing capacity for future business opportunities. Among concerns raised by participants in the review processes, the Manitoba Metis Federation6 is concerned that Metis have not been offered the same opportunities as KCN businesses. The Partnership's analysis of the existing environment; the appropriateness of its mitigation, monitoring and adaptive management plans; and conclusions regarding business opportunities are the subject of review in the environmental review process.
- **Conawapa**: Although the Conawapa ownership structure is not yet finalized, Manitoba Hydro is committed to achieving long-term, sustainable benefits for First Nations in the vicinity of the project with a focus on income, training, employment and business opportunities. The broader regional communities will have access to project benefits, which may include some form of income sharing; these plans are still being developed.
- **Manitoba-Minnesota and North-South Transmission Projects**: Construction of transmission lines is normally conducted over two years: in the first winter, rights-of-way are cleared; during the second winter, towers are erected and lines strung. Clearing

[6] Ibid.

contracts may be awarded to local Aboriginal businesses employing local people, and limited local employment is available with the general contractor during the second phase. In its Bipole III report, the Clean Environment Commission termed the local business opportunities as "modest".

- **Gas**: Since new gas turbines would be developed on privately-owned land in southern Manitoba, northern and Aboriginal businesses would not be expected to receive business preferences. However, southern businesses could benefit from modest opportunities.
- **Wind**: Since new wind farms would be developed on privately-owned land in southern Manitoba, northern and Aboriginal businesses would not be expected to receive business preferences. Southern Aboriginal business may negotiate preferences, particularly if wind farms are located on reserve or Crown lands in southern Manitoba. No preferences were identified in the EISs of the two existing wind farms in Manitoba.
- **DSM**: Power Smart Programs are supported by an extensive network of contractors, with over 2,300 Power Smart registered contractors. One service sector that has realized substantial growth is related to home insulation. Since the introduction of the Home Insulation Program, the number of businesses providing insulation services has increased four-fold, with a similar increase in the capacity of existing contractors active prior to the launch of the program.

Infrastructure and Services

Proponents and/or contractors accept responsibility for providing accommodations for larger construction forces, while employers and/or employees attend to housing infrastructure during the operational phase. First Nation members living on reserve may live in housing supplied by the First Nation. Housing will be the focus of the socio-economic analysis.

- **Keeyask**: Construction workers on the generation project will be housed in a well-equipped camp with on-site recreational facilities, as well as health care and counseling services. The camp will be 140 kilometers via the north access road to Gillam. (The site for a camp for about 50 - 100 workers on the south access road has not been

determined.) Infrastructure and services will be expanded under the Gillam Redevelopment and Expansion Program to meet the growing workforce of Gillam. Few off-reserve First Nation workers are expected to return to live in their home communities, which currently have severe housing shortages and are located some distance from the project site. Among concerns raised by participants in the review processes, the Manitoba Metis Federation7 is concerned that effects on Metis as a distinct group have not been studied. Another participant questioned whether Manitoba Hydro should intervene regarding the lack of housing on First Nation reserves. The Partnership's analysis of the existing environment; the appropriateness of its mitigation, monitoring and adaptive management plans; and conclusions regarding housing are the subject of review in the environmental review process.

- **Conawapa**: See Keeyask. The Conawapa main camp with accommodation for 2,500 people will be located approximately 2 km west of the generating station site.
- **Manitoba-Minnesota and North-South Transmission Projects**: Construction crews are housed in temporary remote camps or, if facilities are available, in local communities.
- **Gas turbines**: Requirements for housing for crews working on gas turbines would be expected to be met through existing service providers.
- **Wind**: Requirements for housing for crews working on wind turbines would be expected to be met through existing service providers.
- **DSM**: Power Smart programs improve the energy efficiency of existing housing stock, including in First Nation and other northern communities.

Personal, Family and Community Life

Different human health concerns are associated with the different resource options. Each is discussed as follows:

- **Keeyask**: Concern has been expressed about past experience with hydroelectric developments regarding negative interactions between non-local construction workers

[7] Ibid.

and local residents. Strategically addressing public safety and associated concerns is of great importance for new projects, which include Conawapa and Bipole III in addition to Keeyask. Several measures will be implemented to limit the potential for adverse worker interaction. Among these measures, almost all workers constructing the generating station will be housed at a fully serviced camp with recreational facilities, lounge, and on-site health care and counseling services. The camp will be on the north side of the river 140 kilometers by road from Gillam. A small camp for 50 – 100 workers will be located on the south side of the river. A Worker Interaction Sub-committee will provide a coordinate approach to monitoring and addressing worker interaction issues across all Manitoba Hydro projects. This committee includes representatives from Manitoba Hydro, Town of Gillam, Fox Lake Cree Nation, RCMP and other stakeholders. Nevertheless, some adverse effects are expected. Among concerns raised by participants in the reviews, the Manitoba Metis Federation8 is concerned about the absence of programs developed specifically for Metis residents.
A second important health-related concern is increasing mercury levels in fish. Flooding of the Keeyask reservoir will result in an increase in mercury levels in fish, which could affect health if people eat too much of this fish. Mercury levels are expected to peak within 3 to 7 years of reservoir impoundment and then gradually diminish over the next three decades to current background levels. To address these concerns, the KCNs' adverse effects agreements provide access to fish from off-system lakes; and a risk communication plan is being developed with the local communities and health officials to promote a healthy fish diet with safe consumption guidelines. Among concerns from participants, the Manitoba Metis Federation is concerned that Metis-specific programs are not available9. Another process participant expressed concern about standards for consumption of fish with mercury.

The Partnership's analysis of the existing environment; the appropriateness of its

[8] Ibid.
[9] Ibid.

mitigation, monitoring and adaptive management plans; and conclusions regarding worker interaction and mercury are the subject of review in the environmental review process.

- **Conawapa**: Please see the previous paragraph under "Keeyask" regarding negative interaction between construction works and local residents.

  Since there is virtually no flooding associated with Conawapa, mercury levels in fish are not expected to rise.
- **Gas**: Please see the information about concerns related to potable water under "Water".
- **Wind**: According to Health Canada, as the number of wind turbines has increased in Canada, public concerns have been expressed about the health effects of wind turbine sound. As a result, Health Canada is collaborating with Statistics Canada on an epidemiological study to evaluate "measureable health endpoints" in people in 8-12 communities at distances up to 10 km from wind turbines. Blood pressure, heart rates, hair cortisol concentrations and sleep actimetry are being measured. The study will also include face-to-face interviews about noise annoyance, health effects, quality of life, sleep quality, perceived stress, lifestyle behaviours (e.g. cigarette smoking and alcohol consumption), prevalent chronic disease and property value impacts. Subjects will also be invited to participate in a physical health measures collection study10. Study results are expected in late 2014.
- **DSM**: Not applicable.

Resource Use

Resource use includes domestic hunting, fishing and gathering, which are protected by treaty and Aboriginal rights. They also provide healthy foods and are important to many people's cultural identity. In southern Manitoba, agriculture is the primary resource use.

[10] Health Canada: Environmental and Workplace Health. 2013. *Health Impacts and Exposure to Sound from Wind Turbines: Updated Research Design and Sound Exposure Assessment.* Ottawa.

- **Keeyask**: Through the construction of the generating station, dykes and roads and the creation of the reservoir, the Keeyask Project will affect hunting, fishing and gathering resources. In addition to mitigation to reduce these effects, each Keeyask Cree Nation has an adverse effects agreement with programs to provide the community members with alternative harvesting opportunities. In voting to support the adverse effects agreements, each community acknowledged that impacts on their Treaty and Aboriginal rights have been addressed. Among concerns raised by participants in the environmental reviews, the Manitoba Metis Federation is concerned programs and agreements have not been developed specifically for the Metis[11]. The Partnership's analysis of the existing environment; the appropriateness of its mitigation, monitoring and adaptive management plans; and conclusions regarding resource use are the subject of review in the environmental review process.
- **Conawapa**: While the environmental assessment is still underway and adverse effects agreements have not been negotiated, Manitoba Hydro expects to achieve results similar to those of Keeyask.
- **Manitoba-Minnesota and North-South Transmission Projects**: Transmission projects have the potential to affect domestic resource users by removing traditional plants and by improving access for other resource users to hunt moose and other game. Predators such as wolves can also use rights-of-way to prey on moose and other game. To mitigate these effects, lines may be routed away from sensitive sites and steps can be taken to lessen access to new rights-of-way. Along with issues related to the loss of harvesting opportunities, participants in the Bipole III review process also expressed concern about the use of herbicides. In response, the Clean Environment Commission recommended measures to limit herbicide use and post areas that have been treated with herbicides. The commission also heard concerns of how the transmission line would interfere with agricultural practices by obstructing farm equipment, irrigation equipment and aerial spraying. The commission recommended Manitoba Hydro consult with local landowners

[11] Please see MMF-MH I-000(b).

to route the line where it will have the least possible impacts on agricultural operations, unless there are clear and compelling reasons to route the line elsewhere.

- **Gas**: Not applicable to gas turbines in Manitoba. However, the exploration and production of natural gas would affect resource harvesting in other jurisdictions.
- **Wind**: Wind development in Manitoba to date has not affected Treaty and Aboriginal rights. If wind farms were developed on reserve or Crown land, appropriate measures could be required. Since wind farms are more likely to occur on private agricultural land, traditional resource use is not expected to be affected. With the exception of limits to aerial spraying, the EISs of the two existing wind farms in Manitoba did not identify concerns related to agricultural practices.
- **DSM**: Not applicable.

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Page No.: p. 53-54

PREAMBLE: "One significant environmental concern of the proposed Keeyask and Conawapa hydro dams relates to the effects of these proposed dam projects on lake sturgeon.; As noted by Manitoba Hydro in the NFAT (Manitoba Hydro 2013, Ch.13 p.54):;"The federal government is considering whether to list lake sturgeon in the Nelson River as endangered under the Species at Risk Act (SARA). Manitoba Hydro's planning is based on the assumption that this will not occur, particularly given the stocking and stewardship programs that are being developed and implemented. Were listing under SARA to occur the Keeyask and Conawapa Projects could be delayed or cancelled. If Manitoba Hydro (and in the case of Keeyask the partnership) decided to proceed with the projects, federal permits would be required." In response to concerns about lake sturgeon, Manitoba Hydro notes in the NFAT filing that (Manitoba Hydro 2013, Ch.13 p.53-54): "Among the aquatic impacts, there would be some loss of spawning and foraging habitat as well as some blockage of fish passage. Extensive mitigation measures have been planned to minimize and offset these effects. These include plans in construction and for turbine design to minimize impacts; development of new habitat and fish passage; and implementation of a fish stocking program. While some short term declines in fish populations are expected, no declines are expected over the long term, and lake sturgeon populations in the region are expected to increase with the stocking and stewardship programs despite the loss of habitat due to the project." While the mitigation measures are notable, there are several concerns being raised about the desirability and effectiveness of Manitoba Hydro's approach.; While recognizing that the purpose of the NFAT review is not to delve into the EIS, we feel it is necessary to share some concerns raised in the EIS review given that they relate directly to statements made in the NFAT submission.; For example, some concerns noted in the information requests for the EIS review process include:; • CAC 0042 remarks on the massive and inexplicable die-offs that occur without warning at Grand Rapids hatchery. • CEC 0031 notes that fish stocking "should be the last mitigation option and not the first" • MB Wildlands 0052B expresses concern about genetic diversity of Sturgeon in the fish stocking programs • CEC 0029 expresses concern that stocking without a suitable habitat will not create viable and self-sustaining populations, and the EIS does not suitably describe the habitat. • PFN 0025 notes, among other things, that the stocking program as described in the EIS is overly general, does not actually propose an actual program, and does not provide results of the 2012 trial. There are several other concerns raised in the IRs, but it should be clear that that the fish stocking program is not a guaranteed success, may not even be a desirable approach, and is insufficiently described to make an accurate assessment of at this point.; For these reasons, it is

uncertain whether Manitoba Hydro is justified in its claims regarding lake sturgeon in the NFAT submission."

QUESTION:

With regards to the potential listing of Lake Sturgeon as a species at risk, please describe how such a listing would impact the structure and timing of the preferred plan, and the desirability of the preferred plan in comparison with the full range of alternatives.

RESPONSE:

A decision to list Lake Sturgeon on the Nelson River under the *SARA* would require strict protection and mitigation measures for the species. For the Keeyask environmental assessment and licensing processes, DFO has indicated that it is taking a precautionary approach to Lake Sturgeon protection, given the COSEWIC assessment from 2006. Manitoba Hydro expects that the DFO will continue to follow this approach for Conawapa.

The precautionary approach being taken by the DFO means that the protection measures that would be incorporated into the conditions of a permit under the *Fisheries Act* are consistent with what could be required if it were listed under the *SARA*. Correspondingly, the mitigation measures for the effects of Keeyask and Conawapa will have to satisfy those strict requirements. If Lake Sturgeon are listed on the Nelson River, the project proponents – the Keeyask Partnership and Manitoba Hydro in the case of Keeyask and Manitoba Hydro for Conawapa – would apply for permits to construct and operate the project.

Because the mitigation measures for Keeyask and Conawapa will have to meet protection requirements that are consistent with what could be required if the species is listed under *SARA*, it is anticipated that any cost and timing delays that could result from a potential Lake Sturgeon listing and permitting requirements would not be sufficient to materially alter the ranking of the preferred plan in comparison with the full range of alternatives. Table 10.2.4, in Chapter 10, page 53 of the NFAT submission examines a one year delay in the in-service dates

of both Keeyask and Conawapa and indicates that such a delay would result in a $97 million NPV cost in the reference scenario. This $97 million reduction in benefit for the Preferred Plan is relatively small compared to the $1,696 million NPV benefit of the Preferred Plan relative to the All Gas Plan.

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Page No.: p. 59-60

PREAMBLE: "In the terms of reference for the NFAT, Manitoba Hydro was required to assess the socio-economic impact of the preferred plan compared to alternatives, where socio-economic impacts were defined in PUB Order 92/13 as: • A critical analysis of the socio-economic impacts and benefits of Manitoba Hydro's Preferred Development Plan and alternative Plans. Specifically, a high level summary of potential effects to people in Manitoba, especially Northern and Aboriginal communities, including such things as employment, training and business opportunities; infrastructure and services; personal family and community life; and resource use. In response to this requirement, Chapter 13 of the Manitoba Hydro NFAT submission provides a discussion of local and regional community impacts of the preferred plan. Two passages of note are shown below: • "The Keeyask G.S. assessment has indicated that there would be significant employment benefits throughout the region, and spin-off business benefits in Gillam and Thompson. Gillam would realize longer-term benefits because of the permanent jobs that would be located there to support Keeyask operations. While there are concerns about wage pressure and cost-of-living impacts that could result, these are not expected to be significant because of an anticipated business closure and consequent weakness elsewhere in the regional economy" (Manitoba Hydro 2013, Ch. 13 p.59). • "As with other major projects in remote areas, there would be both positive and negative potential impacts on families and community well-being. The increased income and employment opportunities can significantly benefit families, but at the same time they can give rise to undesirable activities such as drug and alcohol abuse" (Manitoba Hydro 2013, Ch. 13 p.60). While the discussion of positive and negative impacts provides a good starting point, it is notably incomplete. For example, Chapter 13 makes no reference to boom and bust effects, which Manitoba Hydro acknowledged may be expected to occur in its response to information requests on the EIS review (IR CEC Rd1 CAC-0069) "There is no doubt that a project of this nature has the potential to create a boom-bust cycle within the KCNs and in other local communities. The extent to which this boom-bust is experienced will, in part, depend on the level of participation in the Project by individual KCNs members, the timing of other future developments in the region (e.g., development of the proposed Conawapa Generation Project) and measures implemented by leadership at the community level. Counseling services, including financial counseling, are provided for site employees and may help to assist individual employees and their families with this transition at the end of the Project construction period." Secondly, the proposed Keeyask dam is anticipated to bring economic benefits but also harm and sadness to the Cree Nations Partners, as

noted in the EIS (Keeyask HLP 2012, 6.428), but seemingly not discussed in the NFAT submission: "Adverse socio-economic effects identified by CNP during their negotiation of their AEA included: Loss of Gull Rapids, as well as sacred sites, unknown burial sites and archaeological artifacts due to flooding; Loss of historical and spiritual connection to the land through flooding; Harm to their emotional well-being as Project effects are seen as damaging and disrespectful to the land/failing to properly care for the land; Increased risk of drug and alcohol abuse, sexual abuse and family violence; Increase in mercury levels in certain fish in Gull Lake will pose a health hazard; Open water and winter travel may become more dangerous; Uneven distribution of the costs and benefits of the Project amongst CNP Members may cause increased stress and strain within the community; and Loss of trapping income." Ultimately, it appears that for Manitoba Hydro to provide the required critical analysis of the socio-economic impacts of the various alternatives, a much more in-depth discussion is required."

QUESTION:

Please provide greater elaboration on the socio-economic impacts of the preferred plan and its alternatives, including attention to (but not limited to): (i) boom and bust dynamics (ii) the impacts of flooding and mercury contamination of the traditional livelihoods of both present and future generations (iii) what steps Manitoba Hydro is taking to ensure that the income generated from the projects (at both individual and community levels) are used for constructive as opposed to destructive ends and the range of uncertainty about the likely success of these steps (iv) the equity effects of the anticipated distribution of project income among members of the First Nations communities"

RESPONSE:

On September 30, 2013 Manitoba Hydro undertook to provide matrices of macro environmental and socio-economic issues comparing Keeyask, Conawapa, gas turbines and wind generation. The matrices summarize the various components of the PUB's definitions of macro environmental and socio-economic as defined in PUB Order 92/13.

PUB Order 119/13 added DSM to the resource options to be considered in the matrices, and Manitoba Hydro has chosen to also include transmission projects.

The socio-economic matrix will note these issues. Please refer to CAC/MH I-231(a) for the matrices.

REFERENCE: Volume: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: N/A; Page No.: p.62

PREAMBLE: In the terms of reference for the NFAT, Manitoba Hydro was required to assess the socio-economic impact of the preferred plan compared to alternatives, where socio-economic impacts were defined in PUB Order 92/13 as: • A critical analysis of the socio-economic impacts and benefits of Manitoba Hydro's Preferred Development Plan and alternative Plans. Specifically, a high level summary of potential effects to people in Manitoba, especially Northern and Aboriginal communities, including such things as employment, training and business opportunities; infrastructure and services; personal family and community life; and resource use. In response to this requirement, Chapter 13 of the NFAT provides a discussion of the bequest value of a hydro dam, where bequest value is defined as "the value of the assets that will benefit future generations of Manitobans over the very long term" (Manitoba Hydro 2013, Ch.13 p.62). For the purposes of the NFAT, MH focuses on the costs and benefits of maintaining the power system from 2047-2090. While hydro dams certainly represent a bequest value insofar as the future benefits from infrastructure developments today, there are equally valid concerns about the future being saddled with significant environmental modifications done today. A hydro dam is for all practical purposes irreversible as recognized by Manitoba Hydro in the EIS. Any negative future socio-economic and macro-environmental impacts of the dam (both those that are known now as well as things we have not anticipated) represent bequest costs offloaded onto future generations. Furthermore, evaluating the bequest value of individual electrical generating assets is insufficient by itself. Future generations might benefit more from better building codes that reduce electricity consumption, or the promotion of non-electrical heating infrastructure, or serious investments in conservation and demand management. It is difficult to think of a major disturbance to the environment (and its consequent socio-economic cost) having only a positive bequest value, particularly when there are less invasive and more flexible alternatives.

QUESTION:

Please further elaborate upon the bequest value analysis, paying attention to: the bequest value of preserving the natural environment in an unflooded state

RESPONSE:

As noted in Chapter 13, bequest value could apply to a wide range of environmental and social attributes. The test in a benefit-cost analysis is whether there is a present willingness to pay for the attribute in question. There are very tangible benefits to the hydroelectric assets remaining at the end of the planning period. The application of a lower discount rate, as is generally considered appropriate for intergenerational effects, would suggest hydroelectric assets offer a bequest value in excess of the residual value of assets taken into account in the market valuation of the alternative plans. There could be an existence and bequest value with respect to the natural environments that would be affected by the developments in the different plans; that is part of the non-monetized effect or trade-off that policy makers will have to consider in their final decisions on this matter. There could also be a preference for 'bequesting' renewable sources of energy, including hydropower, but it is not clear how widespread that preference would be or how significant Manitobans' willingness to pay for it would be.

REFERENCE: Volume: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Page No.: p. 62

PREAMBLE: In the terms of reference for the NFAT, Manitoba Hydro was required to assess the socio-economic impact of the preferred plan compared to alternatives, where socio-economic impacts were defined in PUB Order 92/13 as: • A critical analysis of the socio-economic impacts and benefits of Manitoba Hydro's Preferred Development Plan and alternative Plans. Specifically, a high level summary of potential effects to people in Manitoba, especially Northern and Aboriginal communities, including such things as employment, training and business opportunities; infrastructure and services; personal family and community life; and resource use. In response to this requirement, Chapter 13 of the NFAT provides a discussion of the bequest value of a hydro dam, where bequest value is defined as "the value of the assets that will benefit future generations of Manitobans over the very long term" (Manitoba Hydro 2013, Ch.13 p.62). For the purposes of the NFAT, MH focuses on the costs and benefits of maintaining the power system from 2047-2090. While hydro dams certainly represent a bequest value insofar as the future benefits from infrastructure developments today, there are equally valid concerns about the future being saddled with significant environmental modifications done today. A hydro dam is for all practical purposes irreversible as recognized by Manitoba Hydro in the EIS. Any negative future socio-economic and macro-environmental impacts of the dam (both those that are known now as well as things we have not anticipated) represent bequest costs offloaded onto future generations. Furthermore, evaluating the bequest value of individual electrical generating assets is insufficient by itself. Future generations might benefit more from better building codes that reduce electricity consumption, or the promotion of non-electrical heating infrastructure, or serious investments in conservation and demand management. It is difficult to think of a major disturbance to the environment (and its consequent socio-economic cost) having only a positive bequest value, particularly when there are less invasive and more flexible alternatives.

QUESTION:

Please further elaborate upon the bequest value analysis, paying attention to: the bequest values of other renewable generating, conservation and demand management options (e.g. wind, solar, biomass heating, enhanced DSM).

RESPONSE:

Please see Manitoba Hydro's response to CAC/MH I-233(a)(i).

REFERENCE: Chapter 1: Introduction; Page No.: 11, line 20

PREAMBLE: "The terms of reference provide for consideration of the macro environmental impact of the Plan as compared to alternatives. The term macro-environmental is defined in PUB Order 92/13. "As part of this commitment, Manitoba Hydro has implemented an Environmental Management System (EMS) registered to the ISO 14001 standard. An EMS provides a framework that helps to manage environmental risk and improve environmental performance. The Manitoba Hydro EMS enables identification of environmental impacts, the setting of goals to manage them, implementation of plans to meet those objectives, and evaluation of performance. Such a framework allows Manitoba Hydro to make continual improvements to the EMS and to our environmental performance."

QUESTION:

Please provide the two most recent evaluations of Manitoba Hydro performance under the ISO 14001 Standard.

RESPONSE:

CAC withdrew this information request.

REFERENCE: Volume: Chapter 1: Introduction; Section: N/A; Page No.: 19

PREAMBLE: "The terms of reference provide for consideration of the macro environmental impact of the Plan as compared to alternatives. The term macro-environmental is defined in PUB Order 92/13. Manitoba Hydro states: "The power resource planning process begins with an assessment of the need for new supply to determine both the timing and capacity and/or energy requirements over a multi-decade planning horizon. Based on this assessment, Manitoba Hydro selects suitable resources from an inventory of potential new resource options and combines suitable resource options into several alternative development plans that cover the entire study period. Each development plan is run through detailed model simulations of the Manitoba Hydro system to determine the water flow-dependent costs and revenues, including variable operating and maintenance expenses, fuel costs and export revenues. These outputs are combined with other costs such as capital, water rentals, fixed operating and maintenance expenses, and are assessed to determine their relative economic and financial attractiveness." In Dave Lamont & John Gerhard, The Treatment of Energy Efficiency in Integrated Resource Plans: A Review of Six State Practices , January 2013, the authors note that integrated resource planning is generally defined as: "a process that identifies options for meeting customers' anticipated needs for electric service in a way that addresses multiple objectives that may be imposed by legislation, Public Utility Commissions, environmental concerns, or customer concerns. In theory, this process puts all options on the table, evaluates them equally against a set of certain objectives, and chooses a portfolio of resources that best meets those objectives. Again, in theory, all resources, from both the supply side and the demand-side, would receive comparable treatment in the IRP process." They go on to observe that within the concept of modern integrated resource planning: "Energy efficiency is an important resource, often the lowest cost resource available to planners; it mitigates a variety of risks, such as the risk of impending carbon legislation and other environmental regulations affecting air and water quality; energy efficiency brings multiple benefits in addition to offsetting energy consumption, such as relieving stress on and deferring required investments into transmission and distribution systems; further, energy efficiency can be acquired in a manner that mirrors the addition of supply side resources (i.e., as an Energy Efficiency Power Plant3). Given these values, it would make sense for planners to treat energy efficiency like any other resource in the IRP. Doing so would allow energy efficiency to compete dynamically for utility investments, just like other resources do." Leading practitioners of integrated resource planning include the state of Oregon: "The Oregon Commission established integrated resource planning for all regulated utilities in Order No. 89-507 (1989) and updated guidelines and requirements in Order Nos. 07-

002 (2007)8, 08-339 (2008, treatment of environmental costs) and 09- 041 (2009 rulemaking). The Commission mandates a least-cost planning regime, but that does not mean an exclusive focus on cost. The Commission explicitly defines this process to be one that identifies resources that provide the best mix of cost and risk. Utilities must evaluate all known demand- side resources as part of the planning process, on a consistent and comparable basis with supply side resources. "

QUESTION:

Please confirm that in the development of the Hydro alternative development plans, DSM was not treated as a resource option and that instead DSM levels were held constant for all alternatives considered.

RESPONSE:

In the development of the resource plans discussed in Chapters 8 to 11, DSM levels were held constant for all alternatives considered. The DSM programs and levels were based on marginal costs derived from the same type of plan evaluation as was used in these NFAT chapters. Thus the DSM was considered as a resource option although not as a competing option in the same set of plan evaluations.

Chapter 12 evaluated three plans with two additional levels, 1.5 times and 4 times, DSM and concluded that the economic ranking of the plans was not altered by the wide range of DSM evaluated (up to four times the incremental DSM included in the main plan evaluations.)

REFERENCE: Chapter 1: Introduction; Section: 19.

PREAMBLE: The terms of reference provide for consideration of the macro environmental impact of the Plan as compared to alternatives. The term macro-environmental is defined in PUB Order 92/13. Manitoba Hydro states: "The power resource planning process begins with an assessment of the need for new supply to determine both the timing and capacity and/or energy requirements over a multi-decade planning horizon. Based on this assessment, Manitoba Hydro selects suitable resources from an inventory of potential new resource options and combines suitable resource options into several alternative development plans that cover the entire study period. Each development plan is run through detailed model simulations of the Manitoba Hydro system to determine the water flow-dependent costs and revenues, including variable operating and maintenance expenses, fuel costs and export revenues. These outputs are combined with other costs such as capital, water rentals, fixed operating and maintenance expenses, and are assessed to determine their relative economic and financial attractiveness." In Dave Lamont & John Gerhard, The Treatment of Energy Efficiency in Integrated Resource Plans: A Review of Six State Practices, January 2013, the authors note that integrated resource planning is generally defined as: "a process that identifies options for meeting customers' anticipated needs for electric service in a way that addresses multiple objectives that may be imposed by legislation, Public Utility Commissions, environmental concerns, or customer concerns. In theory, this process puts all options on the table, evaluates them equally against a set of certain objectives, and chooses a portfolio of resources that best meets those objectives. Again, in theory, all resources, from both the supply side and the demand-side, would receive comparable treatment in the IRP process." They go on to observe that within the concept of modern integrated resource planning: "Energy efficiency is an important resource, often the lowest cost resource available to planners; it mitigates a variety of risks, such as the risk of impending carbon legislation and other environmental regulations affecting air and water quality; energy efficiency brings multiple benefits in addition to offsetting energy consumption, such as relieving stress on and deferring required investments into transmission and distribution systems; further, energy efficiency can be acquired in a manner that mirrors the addition of supply side resources (i.e., as an Energy Efficiency Power Plant3). Given these values, it would make sense for planners to treat energy efficiency like any other resource in the IRP. Doing so would allow energy efficiency to compete dynamically for utility investments, just like other resources do." Leading practitioners of integrated resource planning include the state of Oregon: "The Oregon Commission established integrated resource planning for all regulated utilities in Order No. 89-507 (1989) and updated guidelines and requirements in Order Nos. 07-002 (2007)8, 08-339 (2008, treatment of

environmental costs) and 09- 041 (2009 rulemaking). The Commission mandates a least-cost planning regime, but that does not mean an exclusive focus on cost. The Commission explicitly defines this process to be one that identifies resources that provide the best mix of cost and risk. Utilities must evaluate all known demand- side resources as part of the planning process, on a consistent and comparable basis with supply side resources. ”

QUESTION:

Please confirm that in the Manitoba Hydro planning process, known demand-side resources are not treated on a comparable basis with supply side resources.

RESPONSE:

In the main NFAT submission, the same level of DSM resources is included in each of the 15 development plans. From a comparability perspective, the effect of the same level of DSM on a development plan can differ between types of plans. When DSM resources are included in plans which have similar characteristics and mix of resources to those utilized in establishing the marginal generation cost used to evaluate DSM programs, then there is a fair degree of comparability in the evaluation with the supply side resources. For the plans which have significantly different characteristics and mix of resources to those utilized in establishing the marginal generation cost used to evaluate DSM programs, there is less comparability. It is recognized that evaluation of DSM as a competing option in the same set of plan evaluations along with other resource options provides the most comparability.

In the NFAT submission Chapter 12, Manitoba Hydro provided sensitivities with two higher levels of DSM than in the base plans in order to assess the potential impact of DSM options on the NFAT plan comparison. These sensitivities indicated that such increased levels of DSM do not impact the economic ranking of the plans. Such sensitivities do not indicate what the economic level of DSM is but do indicate that consideration of higher levels of DSM would not alter the conclusions of the NFAT on the attractiveness of the Preferred Plan and alternatives.

Manitoba Hydro's preferred plan along with Pathways 4 and 5 include a commitment to continue to update its DSM plans and pursue the economic level of DSM.

In keeping with that commitment, in the process of updating the DSM plan over the winter of 2013/14, Manitoba Hydro will evaluate the possibility of a higher level of DSM. Manitoba Hydro will strive to provide the NFAT process evaluations of two levels of DSM before the hearings. These two levels would approach the type of levels studied in the NFAT Chapter 12 sensitivities. These evaluations would include sequence evaluations which consider the DSM load savings and DSM cost in plans with supply side options and export/import benefits; such evaluations would provide the fullest comparability referenced above.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Page No.: 5, line 25

PREAMBLE: The following were the results of the JKDA referenda: TCN, 61% in favour; WLFN, 94%; YFFN, 83%; and FLCN, 87%.

QUESTION:

"Please provide the referendum question for each of the KCN. For each community in which referenda were taken please indicate whether the rules of the referendum required that a turnout of more than 50% of eligible voters was required before the vote was considered valid. For each community in which referenda were taken please outline what percentage of the eligible voters actually voted."

RESPONSE:

The following are the referendum questions for each of the KCN:

- Do you support the Chief and council of Tataskweyak Cree Nation signing the proposed Joint Keeyask Development Agreement (JKDA)?
- Do you support the Chief and Council of War Lake First Nation signing the proposed Joint Keeyask Development Agreement (JKDA)?
- Do you support the Chief and Council of York Factory First Nation signing the proposed Joint Keeyask Development Agreement (JKDA)?
- Do you support the Chief and Council of Fox Lake Cree Nation signing the proposed Joint Keeyask Development Agreement (JKDA)?

The following are the rules of the referendum regarding voter participation:

- Article 3 Ratification of the JKDA states in section 3.6 The Referendum to determine whether members support the signing of the JKDA by Chief and Council shall have received a sufficient level of support if:

(a) one third (1/3) of all members eligible to vote, vote; and

(b) a majority of votes cast are cast in favour of the referendum question;

subject to Chief and Council, by Council resolution made prior to the commencement of the referendum process, establishing a higher threshold.

The following lists the number of eligible voters and number who participated in each community:

- TCN: total number of eligible voters – 1909; total number of ballots cast – 753
- WLFN: total number of eligible voters – 158; total number of ballots cast – 70
- YFFN: total number of eligible voters – 713; total number of ballots cast – 260
- FLCN (note: FLCN established a threshold for its first referendum, requiring 50% of eligible members to vote; when this was not achieved, a second referendum was held, with the following results): total number of eligible voters – 734; total number of ballots cast – 345

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.1.3.2; Page No.: 24, page 39, table 7.6

PREAMBLE: The terms of reference provide for consideration of the macro environmental impact of the Plan as compared to alternatives. The term macro-environmental is defined in PUB Order 92/13. Manitoba Hydro discusses alleged residual effects of the generation and infrastructure projects in section 2.1.3.2 of its evidence. Alleged residual effects on the aquatic environment are referenced on page 24 of Chapter 2. No mention of increased methyl mercury levels appears in the aquatic environment discussion. In table 7.6, under selected resource option characteristics, Manitoba Hydro identifies mercury as one of the characteristics associated with the Keeyask Hydro-electric generating station. In its Cumulative Effects Summary filed in CEC Round 1-20 (EIS), Manitoba Hydro concedes that: "Increased methyl mercury levels, especially in jackfish and pickerel in Gull Lake and to a lesser extent in Stephens Lake, are expected during the period after impoundment. These levels are estimated to peak about 3 to 7 years after impoundment and then return to current levels over about 30 years." As stated in the footnotes to Table 5-3 in the HHRA (Human Health Risk Assessment) [Appendix 5C to the SE SV]: "there was not sufficient information to do a length-class analysis of mercury concentrations under post-impoundment conditions." As noted in the preamble to CAC 1 -0024a (EIS): "The results of the HHRA (Human Health Risk Assessment) present risk quotient values above 1 ... In addition, Section7.2.1 in the Fish Quality assessment indicated that mercury concentrations can remain above preimpoundment levels for 20-30 years." As noted in the preamble to CAC 1-0019 (EIS): " The US EPA (2013, 2001) has derived an oral reference concentration for methyl mercury of 0.1 µg/kg-day, which is more conservative than the Health Canada value of 0.2 µg/kg-day selected for use in the HHRA." As noted in the preamble to CAC Round 1 – 33 (EIS): "Section 6.0 describes uncertainty related to mercury concentrations in the environment, toxicity reference values, and food consumption rates. Page 5C-66 states that "the prediction of the magnitude and extent of the changes in environmental concentrations was considered to be beyond the scope of the HHRA".

QUESTION:

Can Manitoba Hydro confirm that its HHRA (Human Health Risk Assessment) in the Keeyask EIS suggested a post-impoundment risk that is more than 14 fold above the Health Canada

tolerable daily intake? If this cannot be confirmed, please provide Manitoba Hydro's interpretation of the post-impoundment risk associated with Keeyask.

RESPONSE:

Please see Manitoba Hydro's response to CAC/MH I-231(a).

On September 30, 2013, Manitoba Hydro undertook to provide matrices of macro environmental and socio-economic issues comparing Keeyask, Conawapa, gas turbines and wind generation. The matrices will address the PUB's definitions of macro environmental and socio-economic as set out in PUB Order 92/13. Based on this undertaking, CAC withdrew this information request.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.1.3.2; table 7.6; Page No.: 24; 39

PREAMBLE: The terms of reference provide for consideration of the macro environmental impact of the Plan as compared to alternatives. The term macro-environmental is defined in PUB Order 92/13. Manitoba Hydro discusses alleged residual effects of the generation and infrastructure projects in section 2.1.3.2 of its evidence. Alleged residual effects on the aquatic environment are referenced on page 24 of Chapter 2. No mention of increased methylmercury levels appears in the aquatic environment discussion. In table 7.6, under selected resource option characteristics, Manitoba Hydro identifies mercury as one of the characteristics associated with the Keeyask Hydro-electric generating station. In its Cumulative Effects Summary filed in CEC Round 1-20 (EIS), Manitoba Hydro concedes that: "Increased methylmercury levels, especially in jackfish and pickerel in Gull Lake and to a lesser extent in Stephens Lake, are expected during the period after impoundment. These levels are estimated to peak about 3 to 7 years after impoundment and then return to current levels over about 30 years." As stated in the footnotes to Table 5-3 in the HHRA (Human Health Risk Assessment) [Appendix 5C to the SE SV]: "there was not sufficient information to do a length-class analysis of mercury concentrations under post-impoundment conditions." As noted in the preamble to CAC 1 -0024a (EIS): "The results of the HHRA (Human Health Risk Assessment) present risk quotient values above 1 ... In addition, Section7.2.1 in the Fish Quality assessment indicated that mercury concentrations can remain above preimpoundment levels for 20-30 years." As noted in the preamble to CAC 1-0019 (EIS): " The US EPA (2013, 2001) has derived an oral reference concentration for methylmercury of 0.1 µg/kg-day, which is more conservative than the Health Canada value of 0.2 µg/kg-day selected for use in the HHRA." As noted in the preamble to CAC Round 1 – 33 (EIS): "Section 6.0 describes uncertainty related to mercury concentrations in the environment, toxicity reference values, and food consumption rates. Page 5C-66 states that "the prediction of the magnitude and extent of the changes in environmental concentrations was considered to be beyond the scope of the HHRA".

QUESTION:

"Can Manitoba Hydro confirm that the US environmental protection agency tolerable daily intake limit is one half the Canadian limit?"

RESPONSE:

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

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Page No.: 23, lines 9-12

PREAMBLE: The terms of reference provide for consideration of the macro environmental impact of the Plan as compared to alternatives. The term macro-environmental is defined in PUB Order 92/13.

Hydro claims that:

"lake sturgeon will be stocked in the Keeyask reach of the Nelson River. Stocking is a proven technique for increasing sturgeon populations, and it is expected to increase regional populations in the Kelsey-Kettle reach of the Nelson River."

In the preamble to CEC 1-0031 (EIS), it is stated:

"It is indicated in Appendix 1A- Part 2, page 1 of the Aquatic Supporting Volume that the stocking of Lake Sturgeon is a proven method for increasing numbers and has been an important feature of many recovery plans. It is our opinion that this is likely only true where the habitat still exists and the decline was due to overfishing or pollution that has been rectified. We are not aware that this has been used as a proven mitigation method relative to hydroelectric development."

In the response to CEC 1-0029 (EIS), Hydro states:

"Lake sturgeon in the study area consist of three groups inhabiting: Split Lake and its tributaries; Clark Lake to Gull Rapids; and Stephens Lake. **Although habitat in the Clark Lake to Gull Rapids reach (where the Project would be developed) currently supports all life history stages, numbers are low, and the long-term sustainability is uncertain.** Numbers may be increasing in the Split Lake area, suggesting this population may persist. **The extremely small number of spawning lake sturgeon at Gull Rapids makes it unlikely that the Stephens Lake group is presently self-sustaining**." [Emphasis added]

QUESTION:

Can Manitoba Hydro point to any peer-reviewed articles concluding that stocking of Lake Sturgeon has been a proven mitigation method relative to Hydro-electric development? If so, please provide them.

RESPONSE:

Please see the response to CAC/MH-231(a). On September 30, 2013 Manitoba Hydro undertook to provide matrices of macro environmental and socio-economic issues comparing Keeyask, Conawapa, gas turbines and wind generation. The matrices summarize the various components of the PUB's definitions of macro environmental and socio-economic as defined in PUB Order 92/13. Based on this undertaking, CAC withdrew this information request.

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QUESTION:

Please provide electronic links to all learned articles relied upon in concluding that "stocking is a proven technique for increasing sturgeon populations."

RESPONSE:

Please see CAC/MH-231(a). On September 30, 2013 Manitoba Hydro undertook to provide matrices of macro environmental and socio-economic issues comparing Keeyask, Conawapa, gas turbines and wind generation. The matrices summarize the various components of the PUB's definitions of macro environmental and socio-economic as defined in PUB Order 92/13. Based on this undertaking, CAC withdrew this information request.

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QUESTION:

"Does Manitoba Hydro agree that potential construction effects on Lake Sturgeon from Keeyask are:

- Mortality or injury may result from stranding during cofferdam dewatering, exposure to blasting, entrainment on intake pipes, and increased harvest by workers.
- Health could be negatively affected by decreases in water quality resulting from in stream construction or accidental spills.
- Disruption of spawning in Gull Rapids due to disturbance by construction activities and habitat loss/alteration.
- Increased noise and rapid changes in water levels and velocities may cause individuals from Gull Lake to emigrate upstream or downstream.
- Sediment deposition in Stephens Lake may alter sub-adult and young-of-the-year habitat."

RESPONSE:

Please see CAC/MH-231(a). On September 30, 2013, Manitoba Hydro undertook to provide matrices of macro environmental and socio-economic issues comparing Keeyask, Conawapa, gas turbines and wind generation. The matrices will address the PUB's definitions of macro environmental and socio-economic as set out in PUB Order 92/13. Based on this undertaking, CAC withdrew this information request.

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QUESTION:

Does Manitoba Hydro agree that potential operation effects on Lake Sturgeon from Keeyask are:

- Complete loss of spawning habitat in Gull Rapids.

- Potential for fish to become stranded in isolated pools after spillway operation.
- The generating station will act as a barrier to upstream movements.
- Changes in downstream movements due to the presence of the generating station.
- Habitat alterations may reduce the amount of suitable spawning and young-of-the-year habitat in the reservoir.
- The amount of foraging habitat in the reservoir will increase in the long term.
- Increased harvest due to increased access to the area.

RESPONSE:

Please see CAC/MH-231(a). On September 30, 2013, Manitoba Hydro undertook to provide matrices of macro environmental and socio-economic issues comparing Keeyask, Conawapa, gas turbines and wind generation. The matrices will address the PUB's definitions of macro environmental and socio-economic as set out in PUB Order 92/13. Based on this undertaking, CAC withdrew this information request.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Page No.: 24, line 5

PREAMBLE: The terms of reference provide for consideration of the macro environmental impact of the Plan as compared to alternatives. The term macro-environmental is defined in PUB Order 92/13.

In Chapter 2, Hydro states:

"With the exception of recognized population ranges near Thompson, SARA-listed boreal woodland caribou have not been identified by provincial or federal resource managers/regulators in the Keeyask regional study area"

According to Manitoba Hydro's Cumulative Effects Summary found in the response to CEC 1-0020:

"Three groupings of caribou are described for the Caribou Local and Regional Study Areas: barren-ground caribou (Rangifer tarandus groenlandicus); coastal caribou (R. t. caribou), which is a forest-tundra migratory woodland caribou ecotype; and summer resident caribou (summer residents), **a type of woodland caribou whose exact range and herd association is uncertain**." [Emphasis added]

According to Manitoba Hydro's Cumulative Effects Summary:

"Effects since hydroelectric development began on caribou have included habitat loss and alteration, changes in habitat fragmentation, changes in herd size, migration routes, and river crossings. Islands in lakes and peatland complexes have changed since hydroelectric development. Although the number of islands in lakes has increased above historical levels, the quality and quantity of habitat change is uncertain. Calving in the Regional Study Area was noted since the return of caribou in the 1990s."

According to Manitoba Hydro's response to CEC 1-0037a (EIS): "As such, Study Zone 5 is a more appropriate area to assess changes in intactness on a summer resident caribou hypothesized as a boreal woodland caribou population, and using the most conservative population estimate along with the intactness estimates, this group of animals would likely be defined by Environment Canada as Likely as Not Self-sustaining ... If intactness

were assessed over a larger area, linear feature density would be lower due to the relatively low level of development in northern Manitoba."

According to the response to CAC 1-009 (EIS), Manitoba Hydro suggests:

"A third variety of caribou common to the Keeyask region is present year-round, and has been identified by some KCNs as woodland caribou. The calving behaviour of summer residents is similar to that of boreal woodland caribou. This group has recently been identified by some KCNs as migratory woodland caribou. The exact core range, long-term calving frequency, and herd association of these caribou cannot be clearly determined."

QUESTION:

Please indicate whether any of the Keeyask Partner First Nations have suggested that there are additional boreal woodland caribou other than the recognized population ranges near Thompson which might be affected by the project.

RESPONSE:

Please see CAC/MH-231(a). On September 30, 2013 Manitoba Hydro undertook to provide matrices of macro environmental and socio-economic issues comparing Keeyask, Conawapa, gas turbines and wind generation. The matrices summarize the various components of the PUB's definitions of macro environmental and socio-economic as defined in PUB Order 92/13. Based on this undertaking, CAC withdrew this information request.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Page No.: 24, line 5

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QUESTION:

Assuming that the hypotheses that the summer resident caribou are boreal woodland caribou, does Manitoba Hydro agree that it is likely this group of animals would be defined by Environment Canada as Not Self-sustaining?

RESPONSE:

On September 30, 2013 Manitoba Hydro undertook to provide matrices of macro environmental and socio-economic issues comparing Keeyask, Conawapa, gas turbines and wind generation. The matrices summarize the various components of the PUB's definitions of macro environmental and socio-economic as defined in PUB Order 92/13. Based on this undertaking, CAC withdrew this information request. Please see the response to CAC/MH I-231(a).

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: Table 3.1; Page No.: 5

PREAMBLE: "Historically, electricity consumption has been associated with economic activity, as measured by real Gross Domestic Product (GDP). A growing economy is associated with increased electricity consumption while economic downturns have a tendency to reduce or stall the growth of consumption. While the correlation between GDP and electricity consumption has been moderated by shifts away from manufactured goods and more towards services, the decrease in North American electricity consumption during the 2008–2009 economic recession demonstrates that overall economic conditions still have a significant impact on electricity consumption." In Table 3.1, Manitoba Hydro provides the NERC forecast of annual Total Demand Growth Across Regions. In Figure 3.4, Comparison of Forecast GDP, Manitoba Hydro suggests that GDP growth in the US will outstrip GDP growth in Manitoba. At page 6 of the September 5, 2013 PowerPoint document Manitoba Hydro Electric Load Forecast, the corporation summarizes its findings related growth in residential load. September 5, 2013 PowerPoint document Manitoba Hydro Electric Load Forecast."

QUESTION:

"Please provide Manitoba Hydro's understanding of the term total internal demand as employed by NERC and please explain how that term differs from the term load growth as employed by Manitoba Hydro.

RESPONSE:

The "total internal demand" employed by NERC in Table 3.1 is different from the Gross Total Peak used by Manitoba Hydro. NERC's total internal demand excludes station service and includes DSM programs, future HVDC line loss reductions and net export sale and purchase losses. NERC also uses maximum monthly peak, rather than annual peak. As a result of the inclusions, the NERC growth rate is lower than the growth rate expected for Manitoba's domestic load.

The NERC winter peak growth rate of 1.14% reported in the NERC 2012 Long-Term Reliability Assessment is based on Manitoba Hydro's "total internal demand" growing from 4661 MW in January 2014 to 5162 MW in January 2023. The corresponding Gross Manitoba Total Peak from the 2011 Electric Load Forecast that was used as the basis for the 2012 NERC numbers is 4697 MW in January 2013 growing to 5379 MW in January 2023 for an annual growth of 1.52%.

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: Table 3.1; Page No.: 5

PREAMBLE: "Historically, electricity consumption has been associated with economic activity, as measured by real Gross Domestic Product (GDP). A growing economy is associated with increased electricity consumption while economic downturns have a tendency to reduce or stall the growth of consumption. While the correlation between GDP and electricity consumption has been moderated by shifts away from manufactured goods and more towards services, the decrease in North American electricity consumption during the 2008–2009 economic recession demonstrates that overall economic conditions still have a significant impact on electricity consumption." In Table 3.1, Manitoba Hydro provides the NERC forecast of annual Total Demand Growth Across Regions. In Figure 3.4, Comparison of Forecast GDP, Manitoba Hydro suggests that GDP growth in the US will outstrip GDP growth in Manitoba. At page 6 of the September 5, 2013 PowerPoint document Manitoba Hydro Electric Load Forecast, the corporation summarizes its findings related growth in residential load. September 5, 2013 PowerPoint document Manitoba Hydro Electric Load Forecast."

QUESTION:

Does Hydro accept the NERC analysis of Annuals Total Internal Demand Growth for MRO Manitoba as displayed by NERC? If not, please explain where Hydro's analysis differs.

RESPONSE:

Manitoba Hydro provided NERC with the numbers used for the Total Internal Demand for MRO Manitoba as defined in Manitoba Hydro's response to CAC/MH I-240(a), and has verified that they match what Manitoba Hydro has provided.

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Section: Table 3.1; Page No.: 5

PREAMBLE: "Historically, electricity consumption has been associated with economic activity, as measured by real Gross Domestic Product (GDP). A growing economy is associated with increased electricity consumption while economic downturns have a tendency to reduce or stall the growth of consumption. While the correlation between GDP and electricity consumption has been moderated by shifts away from manufactured goods and more towards services, the decrease in North American electricity consumption during the 2008–2009 economic recession demonstrates that overall economic conditions still have a significant impact on electricity consumption." In Table 3.1, Manitoba Hydro provides the NERC forecast of annual Total Demand Growth Across Regions. In Figure 3.4, Comparison of Forecast GDP, Manitoba Hydro suggests that GDP growth in the US will outstrip GDP growth in Manitoba. At page 6 of the September 5, 2013 PowerPoint document Manitoba Hydro Electric Load Forecast, the corporation summarizes its findings related growth in residential load. September 5, 2013 PowerPoint document Manitoba Hydro Electric Load Forecast."

QUESTION:

Please provide any comparable 20 year analysis for the MISO region and MRO-Manitoba Hydro.

RESPONSE:

The NERC Long Term Assessments do not go out past 10 years.

REFERENCE: Chapter 3: Trends and Factors Influencing North American Electricity Supply; Page No.: 7

PREAMBLE: "There are also linkages between electricity prices and demand. Lower power prices tend to spur demand and reduce the incentive for efficiency, which over time puts upward pressure on prices. Higher power prices, on the other hand, tend to do the opposite, spurring new supply and depressing demand, which in turn moderates those high power prices over time." At pages 6, 8 and 9 of the September 5, 2013 powerpoint document Manitoba Hydro Electric Load Forecast, the corporation summarizes its findings related to growth in residential load, general service mass market and general service top consumers. "

QUESTION:

"Please provide any studies or analysis within the possession of Manitoba Hydro that explore the relationship between Manitoba domestic prices and Manitoba load."

RESPONSE:

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

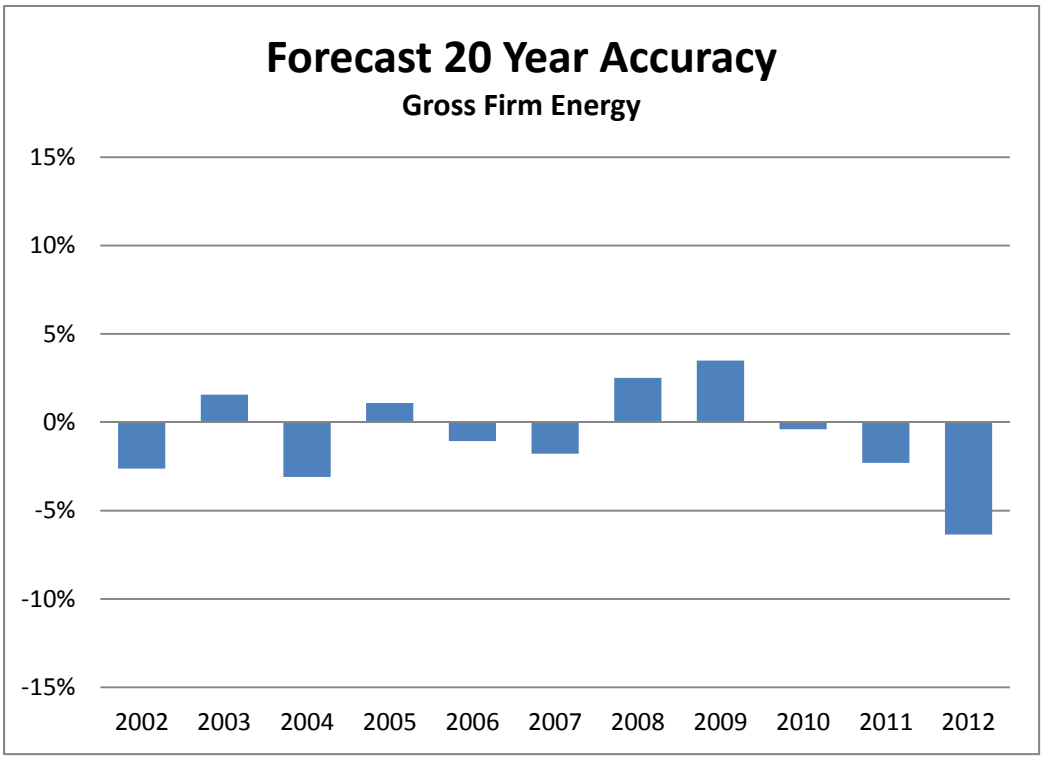
REFERENCE: Sept 5.Transcript.

PREAMBLE: "At pages 11 and 12 of the September 5, 2013 PowerPoint document Manitoba Hydro Electric Load Forecast, the corporation summarizes its findings related to 5 year and 10 year forecast accuracy."

QUESTION:

Please provide the same analysis for a 20 year period.

RESPONSE:



REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Page No.: 55, line 5

PREAMBLE: "The terms of reference provide for a consideration of the macro environmental impact of the Plan as compared to alternatives. The term macro-environmental is defined in PUB Order 92/13. Hydro claims: "The North-South Transmission Project may also need to develop measures to manage effects on woodland caribou, a SARA-listed species that inhabits the project region. Manitoba Hydro has successfully assessed and managed these types of effects with other transmission projects, and will apply that expertise to manage effects related to the North-South Project." "

QUESTION:

"Please provide any evidence relied upon by Manitoba Hydro to suggest it has successfully managed effects on woodland caribou. In particular, please provide any peer reviewed or independent evidence supporting Hydro's contention."

RESPONSE:

Please see Manitoba Hdyro's response to CAC/MH I-231(a). This question is very similar to CAC/MH I-238(a) and CAC/MH I-238(b), which were regarding sturgeon.

Manitoba Hydro undertook on September 30 to provide matrices of macro environmental and socio-economic issues comparing Keeyask, Conawapa, gas turbines and wind generation. The matrices summarize the various components of the PUB's definitions of macro environmental and socio-economic as defined in PUB Order 92/13. Order 119/13 added DSM to the resource options to be considered in the matrices, and Manitoba Hydro has chosen to also include transmission projects.

Manitoba Hydro will include caribou in the environmental matrix.

Please see the response to CAC/MH I-231(a).

REFERENCE: Appendix 4.3 Demand Side Management Potential Study.

QUESTION:

With regard to the DSM potential study, please provide all old draft reports as well as terms of retainer, deliverables and timelines originally agreed to.

RESPONSE:

Please see the response to PUB/MH I-263(a) for the RFP issued for the DSM potential study which outlines the scope of the project, deliverables and timelines.

In addition to the reports dated July 11, 2013 and August 31, 2013 filed with the Business Case submission, Manitoba Hydro also received two earlier draft reports, copies of which are attached to this response:

1. Issued on November 5, 2012 – this is a draft report that was issued strictly to discuss the report layout and structure. Information in chapters 1 to 3 are very similar to the final report, however the remainder of the sections contain very preliminary and unverified information. At this point in the project the baseline forecast had not yet been finalized and the list of measures was still under review.
2. Issued on June 17, 2013 – this is a draft report with preliminary results.

Demand Side Management Potential Study – DRAFT REPORT

Manitoba Hydro

Report Number #1369

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Prepared for:
Manitoba Hydro

Presented on:
November 5, 2012

This report was prepared by

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Walnut Creek, CA 94596

Project Director: I. Rohmund
Project Manager: B. Kester

EXECUTIVE SUMMARY

Forthcoming with final draft.

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CHAPTER | 1

INTRODUCTION

Background

Manitoba Hydro has contracted with Global Energy Partners, now EnerNOC, to conduct a potential study to assess 20-year potentials of energy efficiency (EE) for electricity and natural gas, and demand response (DR). This potential study will provide information to assist Manitoba Hydro in refining their Power Smart program portfolio.

Toward this end, EnerNOC conducted a detailed, bottom-up assessment of the Manitoba Hydro market to deliver forecasts of energy use and peak demand, as well as forecasts of energy and peak-demand savings achievable through energy efficiency and demand response programs. The 20-year potentials study addresses the residential, commercial, and industrial sectors. Results of this task are discussed in two volumes, one for energy efficiency and one for demand response, as described below in the report organization.

EnerNOC also compared the results of the potential savings to those from existing regional potential studies that are specific to Canada and other select studies. This analysis, which appears in both the energy efficiency and demand response reports, also compares these potential studies with regard to methodology, assumptions, approaches, estimated baselines, technical performance, adoption, and program/regulatory context.

Objectives

Key objectives for the study include:

- Conduct a 20-year bottom-up energy efficiency potential study to determine the potential for specific energy efficiency measures to reduce the consumption and peak demand of electricity in the Manitoba Hydro service territory
- Conduct a demand response potential study to determine the potential for reduction in peak demand through demand response programs
- Provides high-level recommendations on refinements to the Smart Power programs

Report Organization

This report is presented in 3 volumes as outlined below. This document is **Volume 2: Energy Efficiency Potential Study**.

- Volume 1, Executive Summary
- Volume 2, Energy Efficiency Potential Study
- Volume 3, Demand Response Potential Study

Definitions of Potential

In this study, we estimate the potential for energy efficiency savings. The savings estimates represent gross savings[1] developed into three types of potential: technical potential, economic potential, and achievable potential. Technical and economic potential are both theoretical limits to efficiency savings. Achievable potential embodies a set of assumptions about the decisions consumers make regarding the efficiency of the equipment they purchase, the maintenance activities they undertake, the controls they use for energy-consuming equipment, and the elements of building construction. Because estimating achievable potential involves the inherent uncertainty of predicting human behaviors and responses to market conditions, we developed low and high achievable potential as boundaries for a likely range. For this reason, we developed a range of achievable potential. These levels are described below.

- **Technical potential** is defined as the theoretical upper limit of energy efficiency potential. It assumes that customers adopt all feasible measures regardless of their cost. At the time of existing equipment failure, customers replace their equipment with the most efficient option available. In new construction, customers and developers also choose the most efficient equipment option. Examples of measures that make up technical potential in the residential sector include:
    - Ductless mini-split air conditioners with variable refrigerant flow
    - Heat pump water heaters
    - LED lighting

    Technical potential also assumes the adoption of every available other measure, where applicable. For example, it includes installation of high-efficiency windows in all new construction opportunities and air conditioner maintenance in all existing buildings with central and room air conditioning. The retrofit measures are phased in over a number of years, which is longer for higher-cost and complex measures.
- **Economic potential** represents the adoption of all **cost-effective** energy efficiency measures. In this analysis, the cost effectiveness is measured by the total resource cost (TRC) test, which compares lifetime energy and capacity benefits to the incremental cost of the measure. If the benefits outweigh the costs (that is, if the TRC ratio is greater than 1.0), a given measure is considered in the economic potential. Customers are then assumed to purchase the most cost-effective option applicable to them at any decision juncture.
- **Achievable - High potential** estimates customer adoption of economic measures when delivered through efficiency programs under ideal market, implementation, and customer preference conditions. Information channels are assumed to be established and efficient for marketing, educating consumers, and coordinating with trade allies and delivery partners. Achievable High potential establishes a maximum target for the EE savings that an administrator can hope to achieve through its EE programs and involves incentives that represent a substantial portion of the incremental cost combined with high administrative and marketing costs.
- **Achievable - Low potential** reflects expected program participation given significant barriers to customer acceptance, non-ideal implementation conditions, and limited program budgets. This represents a lower bound on achievable potential.

[1] Savings in "gross" terms instead of "net" terms means that the baseline forecast does not include naturally occurring efficiency. In other words, the baseline assumes that energy efficiency levels remain fixed as they are today. This rule holds true except in cases where enactment of future codes and standards were on the books before January 2011, e.g. the effects of the EISA 2007 lighting efficiency standard.

Abbreviations and Acronyms

Throughout the report we use several abbreviations and acronyms. Table 1-1 shows the abbreviation or acronym, along with an explanation.

Table 1-1 Explanation of Abbreviations and Acronyms

Acronym	Explanation
AC	Air conditioning
AEO	Annual Energy Outlook
B/C Ratio	Benefit to Cost Ratio
BEST	EnerNOC's Building Energy Simulation Tool
C&I	Commercial and Industrial
CFL	Compact Fluorescent Lamp
DEEM	Database of Energy Efficiency Measures
DEER	Database for Energy-Efficient Resources
DSM	Demand side management
DR	Demand Response
EE	Energy Efficiency
EIA	Energy Information Administration
EISA	Energy Efficiency and Security Act of 2007
EPACT	Energy Policy Act of 2005
EPRI	Electric Power Research Institute
EUI	Energy-use Index
HH	Household
HID	High Intensity Discharge lighting
HPWH	Heat Pump Water Heater
IC	Industry Canada
LED	Light Emitting Diode lamp
LoadMAP	EnerNOC's Load Management Analysis and Planning™ tool
MAR	Market Acceptance Rate
NRCAN	Natural Resources Canada
NWPCC	Northwest Power and Conservation Council
PIF	Program Implementation Factors
RTU	Roof top unit
Sq. ft.	Square feet
STATCAN	Statistics Canada
TRC	Total Resource Cost
UEC	Unit Energy Consumption

CHAPTER | 2

ANALYSIS APPROACH AND DATA DEVELOPMENT

This section describes the analysis approach taken for the study and the data sources used to develop the potential estimates.

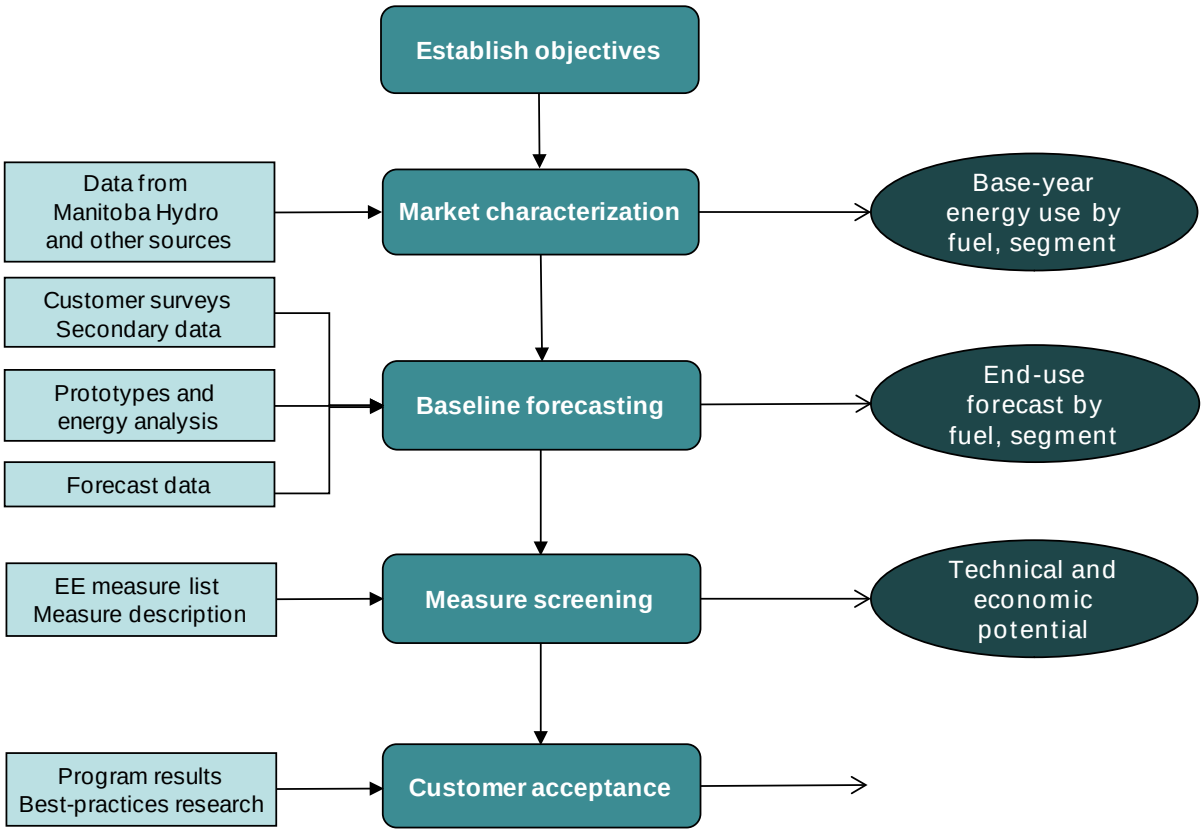
Analysis Approach

To perform the energy efficiency analysis, EnerNOC used a bottom-up analysis approach as shown in Figure 2-1. We took the following steps.

1. Held a meeting with the project team to refine the objectives that were identified in the Manitoba Hydro RFP. This resulted in a work plan for the study.
2. Performed a market characterization to describe sector-level electricity and gas use for the residential, commercial, and industrial sectors for the base year, Manitoba Hydro 2010 (Representing Fiscal year April 2010 through March 2011). This included using utility data and secondary data from sources such as Natural Resources Canada (NRCAN), Industry Canada (IC) and the Energy Information Administration (EIA).
3. Utilized Manitoba Hydro primary market research (such as Manitoba Hydro's 2009 residential customer survey) and secondary sources to understand how customers in the Manitoba Hydro service territory currently use electricity and gas. Combining this information with the market characterization, we developed energy market profiles that describe energy use by sector, segment, and end use for 2010.
4. Developed a baseline electricity and gas forecast by sector, segment, and end use for 2010/11 through 2031/32. Results presented in this volume are through 2031.
5. Identified and analyzed energy-efficiency measures appropriate for the Manitoba Hydro.
6. Estimated three levels of energy-efficiency potential, *Technical, Economic,* and *Achievable*.

These steps are described in further detail throughout the remainder of this chapter.

Figure 2-1 Overview of Analysis Approach



LoadMAP Model

We used EnerNOC's Load Management Analysis and Planning tool (LoadMAP™) version 3.0 to develop both the baseline forecast and the estimates of energy efficiency potential. EnerNOC developed LoadMAP version 1.0 in 2007 and has enhanced it over time, using it for the EPRI National Potential Study and numerous utility-specific forecasting and potential studies. Built in Excel, the LoadMAP framework (see Figure 2-2) is both accessible and transparent and has the following key features.

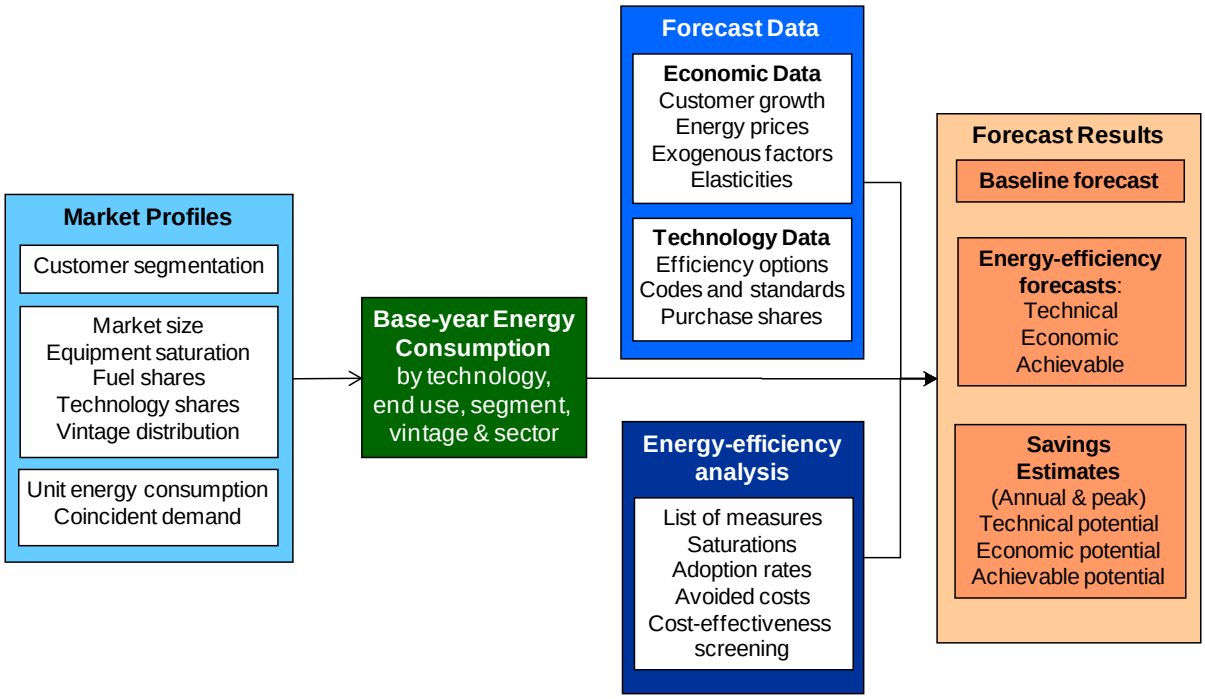
- Embodies the basic principles of rigorous end-use models (such as EPRI's REEPS and COMMEND) but in a more simplified, accessible form.
- Includes stock-accounting algorithms that treat older, less efficient appliance/equipment stock separately from newer, more efficient equipment. Equipment is replaced according to the measure life defined by the user.
- Balances the competing needs of simplicity and robustness by incorporating important modeling details related to equipment saturations, efficiencies, vintage, and the like, where market data are available, and treats end uses separately to account for varying importance and availability of data resources.
- Isolates new construction from existing equipment and buildings and treats purchase decisions for new construction and existing buildings separately.
- Uses a simple logic for appliance and equipment decisions. Other models available for this purpose embody complex decision choice algorithms or diffusion assumptions, and the model parameters tend to be difficult to estimate or observe and sometimes produce anomalous results that require calibration or even overriding. The LoadMAP approach allows the user to drive the appliance and equipment choices year by year directly in the model. This flexible

approach allows users to import the results from diffusion models or to input individual assumptions. The framework also facilitates sensitivity analysis.

- Includes appliance and equipment models customized by end use. For example, the logic for lighting equipment is distinct from refrigerators and freezers.
- Can accommodate various levels of segmentation. Analysis can be performed at the sector level (e.g., total residential) or for customized segments within sectors (e.g., housing type or income level).

Consistent with the segmentation scheme and the market profiles we describe below, the LoadMAP model provides forecasts of baseline energy use by sector, segment, end use, and technology for existing and new buildings. It also provides forecasts of total energy use and energy-efficiency savings associated with the four types of potential.[2]

Figure 2-2 LoadMAP Analysis Framework



Market Characterization

In order to estimate the savings potential from energy-efficient measures, it is necessary to understand how much energy is used today and what equipment is currently being used. The purpose of the market characterization is to develop market profiles that describe current electricity and gas use in terms of sector, customer segment, and end use. The base year for this study is Program Year 2010/11 since that was the most recent year for which a complete set of utility data were available at the start of the analysis.

Segmentation for Modeling Purposes

The market assessment began by defining the market segments (building types, end uses, and other dimensions) that are relevant for Manitoba Hydro. The analysis segmentation used for this project is presented in Table 2-1.

[2] The model computes energy and peak-demand forecasts for each type of potential for each end use as an intermediate calculation. Annual-energy and peak-demand savings are calculated as the difference between the value in the baseline forecast and the value in the potential forecast (e.g., the technical potential forecast).

Table 2-1 Overview of Analysis Segmentation for Potentials Modeling

Segmentation Variable	Market Dimension	Dimension Examples
Sector	Dimension 1	Residential, commercial, industrial
Building type	Dimension 2	Residential (Single family, Multi family, and Apartments, further segmented by heating fuel, geographical location, building vintage and income level.) Commercial (Office, Restaurant, Retail, etc.) Industrial (Mining, Food and Beverage, Pulp and Paper, Chemical, Petroleum, Primary Metals, Miscellaneous Industrial, Other Agriculture, and Other industrial)
Vintage	Dimension 3	Existing and new construction
End uses	Dimension 4	Cooling, space heating, lighting, water heat, motors, etc. (as appropriate by sector)
Fuel	Dimension 5	Electric and Natural Gas
Appliances/end uses and technologies	Dimension 6	Technologies such as lamp type, air conditioning and heating equipment, motors by size, etc.
Equipment efficiency levels for new purchases	Dimension 7	Baseline and higher-efficiency options as appropriate for each technology

Following this scheme, the residential sector was segmented into twenty-nine residential segments as shown in Table 2-2 below, starting with customer segments by home type. The twenty-nine segments are determined by the following:

- **Home type** — Single-family homes, multifamily homes, or apartments
- **Heating fuel**— Natural gas heat, electric heat, or other fuel
- **Geographic location**— Natural gas available, South-no gas available, North-no gas available, reserve-no gas available, or all
- **Building vintage**—homes built before 2000, 2000 to present, or all
- **Income Level**—Non-low income, low income, or all income levels

Table 2-2 Residential Market Segmentation by Housing Type, Base Year FY 2010/11

Segment Name	Home Type	Heating Fuel	Geographic location	Building Vintage	Income Level
SF Gas Pre-2000	Single Family	Gas Heat	Gas Available	Pre-2000	Non-Low Income
SF Gas 2000+	Single Family	Gas Heat	Gas Available	2000-present	Non-Low Income
SF Gas Pre-2000 LI	Single Family	Gas Heat	Gas Available	Pre-2000	Low Income
SF Gas 2000+ LI	Single Family	Gas Heat	Gas Available	2000-present	Low Income
SF Elec GA Pre-2000	Single Family	Electric Heat	Gas Available	Pre-2000	Non-Low Income
SF Elec GA 2000+	Single Family	Electric Heat	Gas Available	2000-present	Non-Low Income
SF Elec GA Pre-2000 LI	Single Family	Electric Heat	Gas Available	Pre-2000	Low Income
SF Elec GA 2000+ LI	Single Family	Electric Heat	Gas Available	2000-present	Low Income
SF Elec SNG Pre-2000	Single Family	Electric Heat	South No Gas	Pre-2000	Non-Low Income
SF Elec SNG 2000+	Single Family	Electric Heat	South No Gas	2000-present	Non-Low Income
SF Elec SNG Pre-2000 LI	Single Family	Electric Heat	South No Gas	Pre-2000	Low Income
SF Elec SNG 2000+ LI	Single Family	Electric Heat	South No Gas	2000-present	Low Income
SF Elec NNG Pre-2000	Single Family	Electric Heat	North No Gas	Pre-2000	Non-Low Income
SF Elec NNG 2000+	Single Family	Electric Heat	North No Gas	2000-present	Non-Low Income
SF Elec NNG Pre-2000 LI	Single Family	Electric Heat	North No Gas	Pre-2000	Low Income
SF Elec NNG 2000+ LI	Single Family	Electric Heat	North No Gas	2000-present	Low Income
SF Elec NG Reserve	Single Family	Electric Heat	Reserve No Gas	All	All
SF Oth All	Single Family	Other	All	All	All
MF Gas	Multi-Family	Gas Heat	All	All	Non-Low Income
MF Gas LI	Multi-Family	Gas Heat	All	All	Low Income
MF Elec	Multi-Family	Electric Heat	All	All	Non-Low Income
MF Elec LI	Multi-Family	Electric Heat	All	All	Low Income
MF Elec NG Reserve	Multi-Family	Electric Heat	Reserve No Gas	All	All
MF Oth All	Multi-Family	Other	All	All	All
Apt Gas	Apartment	Gas Heat	All	All	Non-Low Income
Apt Gas LI	Apartment	Gas Heat	All	All	Low Income
Apt Elec	Apartment	Electric Heat	All	All	Non-Low Income
Apt Elec LI+	Apartment	Electric Heat	All	All	Low Income
Apt Oth All	Apartment	Other	All	All	All

In addition to segmentation by housing type, we identified the set of end uses and technologies that are appropriate for Manitoba Hydro. These are shown in Table 2-3 for the electric technologies and Table 2-4 for the natural gas technologies.

Table 2-3 Residential Electric End Uses and Technologies

End Use	Technology
Cooling	Central Air Conditioning (CAC)
Cooling	Room Air Conditioning (RAC)
Cooling	Evaporative Central Air Conditioning
Space Heating	Electric Resistance
Space Heating	Electric Furnace
Space Heating	Electric Boiler
Space Heating	Supplemental Heat
Combined Heating/Cooling	Geothermal Heat Pump
HVAC Other	Central Exhaust
HVAC Other	Electronic Air Cleaner
HVAC Other	Humidifier
HVAC Other	Dehumidifier
Water Heating	Water Heater
Water Heating	Water Heater - Tankless
Interior Lighting	Screw-in Lamps
Interior Lighting	Linear Fluorescent Lamps
Exterior Lighting	Screw-in Lamps
Appliances	Clothes Washer
Appliances	Clothes Dryer
Appliances	Dishwasher
Appliances	Refrigerator
Appliances	Freezer
Appliances	Second Refrigerator
Appliances	Second Freezer
Appliances	Stove
Appliances	Microwave
Electronics	Personal Computer
Electronics	Monitor
Electronics	Laptop
Electronics	TV
Electronics	Printer/Fax/Copier
Electronics	Set-top Boxes/DVR
Miscellaneous	Pool Pump
Miscellaneous	Pool Heater
Miscellaneous	Hot Tub / Spa
Miscellaneous	Well Pump
Miscellaneous	Furnace Fan
Miscellaneous	Sewage Pump
Miscellaneous	Sump Pump
Miscellaneous	Pressure Pump
Miscellaneous	Sauna
Miscellaneous	Car Block Heater
Miscellaneous	Car Warmer
Miscellaneous	Electric Vehicle
Miscellaneous	Miscellaneous

Table 2-4 Residential Gas End Uses and Technologies

End Use	Technology
Space Heating	Gas Furnace
Space Heating	Gas Boiler
Space Heating	Supplemental Heat
Water Heating	Water Heater
Appliances	Clothes Dryer
Appliances	Stove
Miscellaneous	Pool Heater
Miscellaneous	Gas Barbeque
Miscellaneous	Miscellaneous

For the commercial sector, it is useful to analyze the segments based on the unique characteristics of the building type. For this study, we used the following 19 building types:

- **Large Office**—all types of large offices including large government facilities
- **Small Office**—all types of small offices
- **Restaurant**—fast-food, sit-down and cafeteria-style restaurants
- **Large Retail**—retail establishments such as large box retailers and malls
- **Small Retail**—retail establishments such as small boutiques and mini-malls
- **Grocery**—supermarkets, convenience stores and small markets
- **Large Warehouse**—large storage facilities, including climate-controlled cold storage and unrefrigerated buildings
- **Small Warehouse**—small storage facilities, including climate-controlled cold storage and unrefrigerated buildings
- **Large Education**—colleges and technical schools
- **Small Education**—primary and secondary schools
- **Large Health**—hospitals and large medical office buildings
- **Small Health**—small medical/dental offices and nursing homes
- **Lodging**—motels, hotels, resorts and small inns
- **Bulk Apartments**—master-metered apartments
- **Services**—all types of buildings related to the service industry such as automotive, dry cleaning, salons, etc.
- **Large Recreation Facility**—large recreation facilities such as stadiums and amusement parks
- **Small Recreation Facility**—small recreation facilities such as fitness facilities and miniature golf courses
- **Large Miscellaneous**—all remaining large building types, such as convention centers, museums, etc.
- **Small Miscellaneous**—all remaining small building types, such as police stations, parking garages, etc.

In addition to segmentation by building type, we identified the set of end uses and technologies that are appropriate for Manitoba Hydro. Table 2-5 lists the electric end uses and technologies used in this study. Table 2-6 lists the natural gas end uses and technologies.

Table 2-5 Commercial Electric End Uses and Technologies

End Use	Technology
Cooling	Air-Cooled Chiller
Cooling	Water-Cooled Chiller
Cooling	Roof Top AC
Cooling	Other Cooling
Space Heating	Electric Heating
Combined Heating/Cooling	Roof Top Heat Pump
Ventilation	Ventilation
Water Heating	Water Heating
Interior Lighting	Screw-in
Interior Lighting	High-Bay Fixtures
Interior Lighting	Linear Fluorescent
Exterior Lighting	Screw-in
Exterior Lighting	HID
Exterior Lighting	Linear Fluorescent
Refrigeration	Walk-in Refrigerator
Refrigeration	Reach-in Refrigerator
Refrigeration	Glass Door Display
Refrigeration	Open Display Case
Refrigeration	Icemaker
Refrigeration	Vending Machine
Food Preparation	Oven
Food Preparation	Fryer
Food Preparation	Dishwasher
Food Preparation	Hot Food Container
Office Equipment	Desktop Computer
Office Equipment	Laptop
Office Equipment	Server
Office Equipment	Monitor
Office Equipment	Printer/Copier/Fax
Office Equipment	POS Terminal
Miscellaneous	Non-HVAC Motors
Miscellaneous	Pool Pump
Miscellaneous	Pool Heater
Miscellaneous	Miscellaneous

Table 2-6 Commercial Natural Gas End Uses and Technologies

End Use	Technology
Space Heating	Furnace
Space Heating	Boiler
Space Heating	Other Heating
Water Heating	Water Heating
Food Preparation	Oven
Food Preparation	Fryer
Food Preparation	Broiler
Food Preparation	Griddle
Food Preparation	Range
Food Preparation	Steamer
Miscellaneous	Pool Heater
Miscellaneous	Miscellaneous

The industrial sector is segmented by major industry type. We used the forecast of Top Consumers to help guide the industries to isolate. The segmentation is as follows:

- Mining
- Food and Beverage
- Pulp and Paper
- Chemical
- Petroleum
- Primary Metals
- Miscellaneous Industrial
- Other Agriculture
- Other Industrial

In addition to segmentation by industry, we identified the set of end uses and technologies that are appropriate for Manitoba Hydro. These are shown for the electric and natural gas technologies in Table 2-7 and Table 2-8, respectively.

With the segmentation scheme defined, we then performed a high-level market characterization of electricity and natural gas sales in the base year to allocate sales to each customer segment. We used various Manitoba Hydro data sources to identify the annual sales in each customer segment, as well as the market size for each segment. This information provided sector level control totals (energy use and customers counts/square footage/employee totals) for calibrating the LoadMAP model to known data for the base-year.

Table 2-7 Industrial Electric End Uses and Technologies

End Use	Technology
Cooling	Air-Cooled Chiller
Cooling	Water-Cooled Chiller
Cooling	Roof Top AC
Cooling	Other Cooling
Space Heating	Electric Heating
Ventilation	Ventilation
Water Heating	Water Heating
Interior Lighting	Screw-in
Interior Lighting	High-Bay Fixtures
Interior Lighting	Linear Fluorescent
Exterior Lighting	Screw-in
Exterior Lighting	HID
Exterior Lighting	Linear Fluorescent
Pumps	Pumps
Fans and Blowers	Fans and Blowers
Compressed Air	Compressed Air
Conveyors	Conveyors
Other Motors	Other Motors
Process Heating	Process Heating
Process Cooling and Refrigeration	Process Cooling and Refrigeration
Electro-Chemical	Electro-Chemical
Other Process	Other Process
Miscellaneous	Miscellaneous

Table 2-8 Industrial Gas End Uses and Technologies

End Use	Technology
Space Heating	Furnace
Space Heating	Boiler
Space Heating	Other Heating
Process Heating	Process Heating
Process Cooling	Process Cooling
Other Process	Other Process
Miscellaneous	Miscellaneous

Market Profiles

The next step was to develop market profiles for each sector, customer segment, end use, and technology. A market profile includes the following elements:

- **Market size** is a representation of the number of customers in the segment. For the residential sector, it is number of households. In the commercial sector, it is floor space measured in square feet. For the industrial sector, it is number of employees.
- **Saturations** define the fraction of homes and square feet with the electric or natural gas technologies. (e.g., homes with electric or natural gas space heating, commercial floor space with space cooling). The saturation values are based on Manitoba Hydro's 2009 residential customer survey, 2005 and 1993 Commercial surveys, Manitoba Hydro's internal natural gas potential study, EnerNOC's Energy Market Profiles[3], Natural Resources Canada's Commercial and Institutional Building Energy Use Survey (CIBEUS), and other potential studies including the previous DSM study for Manitoba Hydro.
- **UEC (unit energy consumption) or EUI (energy-use index)** describes the amount of electricity or natural gas consumed in 2010/11 by a specific technology in buildings that have the technology. For the residential sector, we started with the UECs available from Manitoba Hydro's conditional demand model, where available. To fill in holes, we used our databases from previous studies, the previous energy efficiency potential study, the Annual Energy Outlook (AEO), and EnerNOC's BEST simulation tool to develop these values. For the commercial and industrial sectors, we developed the technology-level EUIs using our engineering model, BEST, EnerNOC's Energy Market Profiles database, and other secondary sources. Finally, we adjusted the UECs or EUIs to calibrate to overall building type intensity.

  For electricity, we use UECs expressed in kWh/household for the residential sector, and EUIs expressed in kWh/square foot or kWh/employee for the commercial and industrial sectors respectively. For natural gas, the UECs are expressed in m3/unit.
- **Intensity** for the residential sector represents the average energy use for the technology across all homes in 2010. It is computed as the product of the saturation and the UEC and is defined as kWh/household for electricity or m3/household for natural gas. For the commercial and industrial sectors, intensity, computed as the product of the saturation and the EUI, represents the average use for the technology across all floor space in 2010/11.
- **Usage** is the annual electricity or natural gas use by a technology/end use in the segment. It is the product of the market size and intensity and is quantified in GWh for electricity or MMm3 for gas.

The market assessment results and the market profiles are presented in Chapter 3.

Baseline Forecast

The next step was to develop the baseline forecast of annual electricity and natural gas usage and peak demand for 2010/11 through 2031/32 by customer segment and end use without new utility programs or naturally occurring efficiency scenario. The end-use forecast does include the relatively certain impacts of codes and standards that will unfold over the study timeframe. All such mandates that were defined as of January 2011 are included in the baseline. The baseline forecast is the foundation for the analysis of savings from future EE efforts as well as the metric against which potential savings are measured.

Inputs to the baseline forecast include:

[3] The Energy Market Profiles provide commercial sector energy-use data, by end use and fuel, for 15 building types, based on U.S. DOE's Energy Information Agency's Commercial Building Energy Consumption Survey (CBECS) as well as other secondary data sources. For this analysis, we used Energy Market Profile data for the West North Central region, which includes Minnesota and North Dakota.

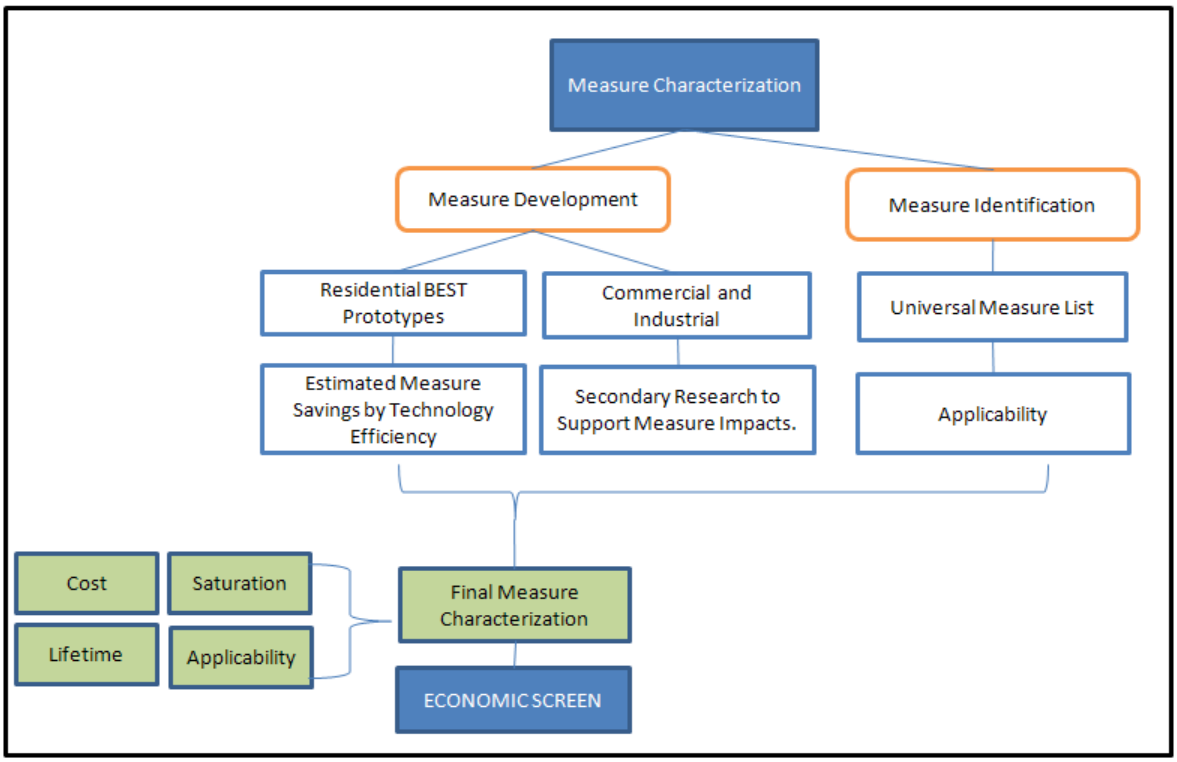
- Current economic growth forecasts (i.e., customer growth, income growth)
- Electricity and natural gas price forecasts
- Trends in fuel shares and equipment saturations
- Existing and approved changes to building codes and equipment standards
- Equipment purchase decisions
- Heating and cooling degree days
- Manitoba Hydro's internally developed forecasts for electricity and natural gas sales

We present the results of the baseline forecast development in Chapter 4.

Energy Efficiency Measure Analysis

This section describes the framework used to assess the savings, costs, and other attributes of energy-efficiency measures. These characteristics form the basis for measure-level cost-effectiveness analyses as well as for determining measure-level savings. For all measures, EnerNOC assembled information to reflect equipment performance, incremental costs, and equipment lifetimes. We used this information, along with Manitoba Hydro's avoided costs data, in the economic screen to determine economically feasible measures. Figure 2-3 outlines the framework for measure analysis.

Figure 2-3 Approach for Measure Assessment



The framework for assessing savings, costs, and other attributes of energy efficiency measures involves identifying the list of energy efficiency measures to include in the analysis, determining their applicability to each market sector and segment, fully characterizing each measure, and performing cost-effectiveness screening. Potential measures include the replacement of a unit that has failed or is at the end of its useful life with an efficient unit, retrofit/early replacement of equipment, improvements to the building envelope, the application of controls to optimize energy use, and other actions resulting in improved energy efficiency.

We compiled a robust list of energy efficiency measures for each customer sector, drawing upon a variety of sources including Manitoba Hydro's measure database, EnerNOC databases, and secondary sources. This universal list of EE measures covers all major types of end-use equipment, as well as devices and actions to reduce energy consumption. If considered today, some of these measures would not pass the economic screens initially, but may pass in future years as a result of lower projected equipment costs or higher avoided costs.

The selected measures are categorized into two types: equipment measures and non-equipment measures, according to the LoadMAP taxonomy:

- **Equipment measures,** or efficient energy-consuming pieces of equipment, save energy by providing the same service with a lower energy requirement than a standard unit. An example is an ENERGY STAR refrigerator that replaces a standard efficiency refrigerator. For equipment measures, many efficiency levels are available for a specific technology ranging from the baseline unit (often determined by code or standard) up to the most efficient product commercially available. For instance, in the case of residential natural gas water heater, this list begins with the federal standard EF 0.57 unit and spans a broad spectrum of efficiency, with the highest efficiency level represented by a EF 0.86 unit.
- **Non-equipment measures** save energy by reducing the need for delivered energy but do not involve replacement or purchase of major end-use equipment (such as a refrigerator or air conditioner). An example would be a programmable thermostat that is pre-set to run the heating system only when people are home. Non-equipment measures fall into one of the following categories:
    - Building shell (windows, insulation, roofing material)
    - Equipment controls (thermostat, occupancy sensors)
    - Equipment maintenance (cleaning filters, changing setpoints)
    - Whole-building design (natural ventilation, passive solar lighting)
    - Lighting retrofits (included as a non-equipment measure because retrofits are performed prior to the equipment's normal end of life)
    - Displacement measures (ceiling fan to reduce use of central air conditioners)
    - Commissioning and retrocommissioning

We developed a preliminary list of EE measures for Manitoba Hydro's review. The final list included in the study is presented in Chapter 5. Note that non-equipment measures can apply to more than one end use. For example, insulation levels will affect the energy use of both cooling and space heating.

Once we assembled the list of EE measures, the project team assessed their energy-saving characteristics. For each measure we characterized incremental cost, service life, and other performance factors. Following the measure characterization, we performed an economic screening of each measure, which serves as the basis for developing the economic potential.

Representative Measure Data Inputs

To provide an example of the measure data, Table 2-9 and Table 2-10 present samples of the detailed data inputs behind both equipment and non-equipment measures, respectively, for the case of residential natural gas furnaces in single-family homes with natural gas space heating built before 2000. Table 2-9 displays the various efficiency levels available as equipment measures, as well as the corresponding useful life, energy usage, and cost estimates. The columns labeled On Market and Off Market reflect equipment availability due to codes and standards or the entry of new products to the market. The on-market of 2010 indicates that the technology is currently commercially available. In Canada there is no natural gas furnace standard in effect, like it is in the United States. If a standard were in place that required a minimum AFUE 96% in 2015, the off market for AFUE 92% would be 2014.

Table 2-9 Sample Equipment Measures for Natural Gas Furnaces – Single Family Home

Efficiency Level	Useful Life	Equipment Cost	Energy Usage(m3/yr)	On Market	Off Market
AFUE 92%	15	$6,516	1,894	2010	n/a
AFUE 96%	15	$6,800	1,787	2010	n/a

Table 2-10 lists some of the non-equipment measures affecting natural gas furnaces in an existing single-family home. All measures are evaluated for cost effectiveness based on the lifetime benefits relative to the cost of the measure. The total savings are calculated for each year of the model and depend on the base year saturation of the measure, the applicability[4] of the measure, and the savings as a percentage of the relevant energy end uses.

Table 2-10 Sample Non-Equipment Measures – Single Family Home, Existing

End Use	Measure	Saturation in 2010[5]	Applica-bility	Lifetime (yrs)	Measure Installed Cost	Energy Savings (%)
Heating	Furnace – Gas, Maintenance	32%	100%	4	$122	4.6%
Heating	Insulation, Ducting	15%	100%	25	$341	3.3%
Heating	Ducting, Repair and Sealing	12%	100%	20	$365	13.6%
Heating	Insulation, Infiltration Control	24%	100%	12	$259	6.8%
Heating	Insulation, Ceiling	36%	90%	30	$993	31.6%
Heating	Insulation, Wall Cavity	50%	100%	30	$998	20.8%
Heating	Insulation, Attic Hatch	15%	50%	18	$69	1.4%
Heating	Doors, Storm and Thermal	38%	100%	12	$311	1.4%
Heating	Windows, ENERGY STAR	61%	100%	25	$7,298	24.7%
Heating	Thermostat, Clock/Programmable	61%	75%	11	$111	6.6%

Screening Measures for Cost-Effectiveness

Only measures that are cost-effective are included in economic and achievable potential. Therefore, for each individual measure, LoadMAP performs an economic screen. This study uses the total resource cost (TRC) test that compares the lifetime benefits (both energy and peak demand) of each applicable measure with its installed cost, which includes material, labor, and administration of a delivery mechanism, such as an energy efficiency program. The lifetime benefits are calculated by multiplying the annual energy and demand savings for each measure

[4] The applicability factors take into account whether the measure is applicable to a particular building type and whether it is feasible to install the measure. For instance, attic fans are not applicable to homes without attics, and in some homes with attics, it may not be feasible to install an attic fan because of lack of space.

[5] Note that saturation levels reflected for the base year change over time as more measures are adopted.

by all appropriate avoided costs for each year, and discounting the dollar savings to the present value equivalent. The analysis uses each measure's values for savings, costs, and lifetimes that were developed as part of the measure characterization process described above. For economic screening of measures, incentives are not included because they represent a simple transfer from one party to another, but have no effect on the overall measure cost.

The LoadMAP model performs this screening dynamically, taking into account changing savings and cost data over time. Thus, some measures pass the economic screen for some — but not all — of the years in the forecast.

It is important to note the following about the economic screen:

- The economic evaluation of every measure in the screen is conducted relative to a baseline condition. For instance, in order to determine the kilowatt-hour (kWh) savings potential of a measure, kWh consumption with the measure applied must be compared to the kWh consumption of a baseline condition.
- The economic screening was conducted only for measures that are applicable to each building type and vintage; thus if a measure is deemed to be irrelevant to a particular building type and vintage, it is excluded from the respective economic screen.

Table 2-11 shows the results of the economic screen for a natural gas furnace for selected years, as well as results for two interior lighting technologies. In 2012/13, the most cost-effective option is AFUE 92%. The table also shows how the economic choice for two of the lighting technology options varies over the study period. For the interior screw-in lighting CFLs are the cost effective technology until 2020/21, when LED lamps become cost effective. If the measure passes the screen (has a benefit-to-cost (B/C) ratio greater than or equal to 1.0), the measure is included in economic potential. Otherwise, it is screened out for that year. If multiple equipment measures have B/C ratios greater than or equal to 1.0, the most efficient technology is selected by the economic screen.

Table 2-11 Economic Screen Results for Selected Residential Equipment Measures

Technology	2012/13	2017/18	2022/23	2027/28	2031/32
Natural Gas Furnace	AFUE 92%	AFUE 92%	AFUE 92%	AFUE 92%	AFUE 92%
Interior Lighting Screw-in	CFL	CFL	LED	LED	LED
Interior Lighting Linear Fluorescent	T5	T5	T5	T5	T5

Energy-Efficiency Potential

The approach we used for this study adheres to the approaches and conventions outlined in the National Action Plan for Energy-Efficiency (NAPEE) Guide for Conducting Potential Studies (November 2007).[6] The NAPEE Guide represents the most credible and comprehensive industry practice for specifying energy-efficiency potential. As described in Chapter 1, four types of potentials were developed as part of this effort: Technical potential, Economic potential, Achievable High potential and Achievable Low potential.

The calculation of Technical and Economic potential is a straightforward algorithm. To develop estimates for **Achievable potential**, we develop market adoption rates for each measure that specify the percentage of customers that will select the highest–efficiency economic option. The Achievable High adoption rates are based on the ramp rates from the Northwest Power &

[6] National Action Plan for Energy Efficiency (2007). *National Action Plan for Energy Efficiency Vision for 2025: Developing a Framework for Change*. www.epa.gov/eeactionplan.

Conservation Council's Sixth Plan as a starting point[7]. The NWPCC has been running programs in the Pacific Northwest for many years, and the portfolio of programs reflects a similar profile of market maturity. The Achievable Low adoption rates start with the Achievable High rates and decrement them by 40% to 75% based on where measures lie in the time horizon of the study or whether they are already familiar inclusions in existing programs. Finally, reasonableness checks are applied by comparing the adoption rates to those from other relevant potential studies and market research.

The overall energy efficiency potential results are available in Chapter 6, and the results by sector are given in Chapter 7.

Data Development

This section details the data sources used in this study, followed by a discussion of how these sources were applied.

Data Sources

The data sources are organized into the following categories:

- Utility-provided data
- EnerNOC' databases and analysis tools
- Energy efficiency measure data
- Other secondary data and reports

Utility-provided Data

In order to appropriately characterize the market in Manitoba Hydro, we asked Manitoba Hydro to provide the following:

- Utility 2010/11 billing data — customers, usage, revenue
- Number of customers and electricity sales by sector and segment (residential, commercial, industrial)
- Coincident peak demand by rate class
- Energy and peak demand forecasts, at the sector level
- Number of customers and natural gas sales by sector and segment (residential, commercial, industrial)
- Customer growth forecast
- Price history and forecast
- Income and household size forecasts
- Cooling and heating degree day history and forecasts
- Recent saturation surveys for residential and commercial customers
- Avoided costs (peak capacity and energy)
- Discount rate
- Escalation rate
- T&D line loss factors
- Program data

[7] The potential factors from the Inland Power and Light service territory were used since it was a better reflection of Manitoba Hydro's service territory.

  - Description of existing energy efficiency programs
  - Description of existing demand-response programs
- Recent energy efficiency potential studies

EnerNOC Databases, Analysis Tools, and Reports

EnerNOC maintains several databases and modeling tools that we use for forecasting and potential studies.

- **Energy Market Profiles Database.** For more than 10 years, EnerNOC staff have maintained profiles of end-use consumption for the residential, commercial, and industrial sectors. These profiles include market size, fuel shares, unit consumption estimates, and annual energy use by fuel (electricity and natural gas), customer segment and end use for 10 regions in the U.S. The Energy Information Administration surveys (RECS, CBECS and MECS) as well as state-level statistics and local customer research provide the foundation for these regional profiles.
- **Building Energy Simulation Tool (BEST)**. EnerNOC's BEST is a derivative of the DOE 2.2 building simulation model, used to estimate base-year UECs and EUIs, as well as measure savings for the HVAC-related measures.
- **Database of Energy Efficiency Measures (DEEM)**. EnerNOC maintains a database of energy efficiency measures for residential, commercial, and industrial segments across the U.S. This is analogous to the DEER database developed for California. EnerNOC updates the database on a regular basis as it conducts new energy efficiency potential studies. The updates draws upon reliable sources including the California Database for Energy Efficient Resources (DEER), the EIA Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case, RS Means cost data, and Grainger Catalog Cost data.
- **EnergyShape™ Database**. database of load shapes includes the following: Residential – electric load shapes for 10 regions, 3 housing types, 13 end uses; Commercial – electric load shapes for 9 regions, 54 building types, 10 end uses; Industrial – electric load shapes, whole facility only, 19 2-digit SIC codes, as well as various 3-digit and 4-digit SIC codes.
- **Recent Studies**. EnerNOC has conducted numerous studies of EE potential in the last five years. We checked our input assumptions and analysis results against the results from these other studies, which include AmerenUE, Los Angeles Department of Water and Power, Consolidated Edison of New York, Avista Utilities, the State of New Mexico, Seattle City Light, and Tennessee Valley Authority. In addition, we used the information about impacts of building codes and appliance standards from a recent report for the Institute for Energy Efficiency.

Other Secondary Data and Reports

Finally, a variety of secondary data sources and reports were used for this study. The main sources are identified below.

- **Natural Resources Canada's Commercial and Institutional Building Energy Use Survey (CIBEUS)**. This survey was conducted by Statistics Canada in 2001. It provides energy intensities, energy consumption data, and energy efficiency characteristics for commercial and institutional buildings.
- **California Statewide Surveys**. California has conducted among the most comprehensive surveys of residential and commercial customers in the world. The Residential Appliance Saturation Survey (RASS) and the Commercial End Use Survey (CEUS) are comprehensive market research studies conducted by the California Energy Commission. These databases provide a wealth of information on appliance use in homes and businesses. RASS is based on information from almost 25,000 homes and CEUS is based on information from a stratified random sample of almost 3,000 businesses in California.

- **Annual Energy Outlook**. The Annual Energy Outlook (AEO), conducted each year by the U.S. Energy Information Administration (EIA), presents yearly projections and analysis of energy topics. For this study, we used data from the 2011 AEO.
- **Electric Power Research Institute – Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.**, also known as the EPRI National Potential Study (2009). In 2009, EPRI hired EnerNOC to conduct an assessment of the national potential for energy efficiency, with estimates derived for the four DOE regions.
- **EPRI End-Use Models (REEPS and COMMEND).** These models provide the elasticities we apply to electricity prices, household income, home size and heating and cooling.
- **Northwest Power and Conservation Council Sixth Plan workbooks.** To develop its Power Plan, the Council maintains workbooks with detailed information about measures.

Data Application

We now discuss how the data sources described above were used for each step of the study.

Data Application for Market Characterization

To construct the high-level market characterization of electricity and natural gas use by households/floor space for the residential, commercial, and industrial sectors, we applied data from Manitoba Hydro, the Annual Energy Outlook, and EnerNOC's Energy Market Profiles Database:

- Historical customer billing data by sector (e.g., residential, commercial, and industrial)
- Manitoba Hydro's 2009 Residential Customer Survey and other utility-provided data to allocate residential customers by housing type
- Manitoba Hydro-provided data and Energy Market Profiles Database to allocate sales and square footage by building type for the commercial sector
- Manitoba Hydro-provided data on energy use by industry type, Energy Market Profiles Database and AEO data to allocate sales and employment for the industrial sector

Data Application for Market Profiles

To develop the market profiles for each segment, we used the following general approach:

1. Used Manitoba Hydro's control totals for each segment. These include market size, segment-level annual electricity use, natural gas use and annual intensity.
2. Used Manitoba Hydro-provided saturation survey data and Energy Market Profiles Database to incorporate information on existing appliance and equipment saturations, appliance and equipment characteristics, and building characteristics.
3. Incorporated secondary data sources to supplement and corroborate the data from items 1 and 2 above.
4. Compared and cross-checked with regional data obtained as part of the EPRI National Potential Study and with the Energy Market Profiles Database, as well as previous energy efficiency potential studies.
5. Ensured calibration to control totals for annual electricity and natural gas sales in each sector and segment.
6. Worked with Manitoba Hydro staff to vet the data against their knowledge and experience.

The specific data elements for the market profiles, together with the key data sources, are shown in Table 2-12.

Table 2-12 Data Applied for the Market Profiles

Model Inputs	Description	Key Sources
Market size	Base-year residential dwellings commercial floor space, and industrial employment	Utility billing data Utility data Energy Market Profiles NRCAN STATCAN IC AEO
Annual intensity	Residential: Annual energy use (kWh/household) Commercial: Annual energy use (kWh/sq ft) Industrial: Annual energy use (kWh/employee)	Utility data Energy Market Profiles CIBEUS AEO Previous studies
Appliance/equipment saturations	Fraction of dwellings with an appliance/technology Percentage of C&I floor space/employment with equipment/technology	Residential Customer Survey Commercial Survey Gas Potential Study Energy Market Profiles CIBEUS Previous studies
UEC/EUI for each end-use technology	UEC: Annual electricity use for a technology in dwellings that have the technology EUI: Annual electricity use per square foot/employee for a technology in floor space that has the technology	Manitoba Hydro's conditional demand model Other: Engineering analysis Energy Market Profiles AEO Results from previous studies
Appliance/equipment vintage distribution	Age distribution for each technology	Utility saturation surveys Previous studies
Efficiency options for each technology	List of available efficiency options and annual energy use for each technology	Manitoba Hydro measure database DEEM DEER NWPCC workbooks Annual Energy Outlook Previous studies
Peak factors	Share of technology energy use that occurs during the peak hour	Utility data EnergyShape database

Data Application for Baseline Forecast

Table 2-13 summarizes the LoadMAP model inputs required for the baseline forecast. These inputs are required for each segment within each sector, as well as for new construction and existing dwellings/buildings.

Table 2-13 Data Needs for the Baseline Forecast and Potentials Estimation in LoadMAP

Model Inputs	Description	Key Sources
Customer growth forecasts	Forecasts of new construction in residential and C&I sectors	Manitoba Hydro customer growth forecast AEO 2011 growth forecast Industry Canada
Equipment purchase shares for baseline forecast	For each equipment/technology, purchase shares for each efficiency level; specified separately for existing equipment replacement and new construction	Shipments data from AEO AEO 2011 forecast assumptions[8] Appliance/efficiency standards analysis
Electricity and gas prices	Forecast of average electricity and gas prices	Manitoba Hydro price forecasts
Utilization model parameters	Price elasticities, elasticities for other variables (income, weather)	EPRI's REEPS and COMMEND models Manitoba Hydro forecasting data Environment Canada AEO 2011

In addition, we implemented assumptions for known future equipment standards as of January, 2011, as shown in Table 2-14 through Table 2-17.

[8] We developed baseline purchase decisions using the Energy Information Agency's *Annual Energy Outlook* report (2011), which utilizes the National Energy Modeling System (NEMS) to produce a self-consistent supply and demand economic model. We calibrated equipment purchase options to match manufacturer shipment data for recent years and then held values constant for the study period. This removes any effects of naturally occurring conservation or effects of future DSM programs that may be embedded in the AEO forecasts.

Table 2-14 Residential Electric Equipment Standards

Today's Efficiency or Standard Assumption | 1st Standard (relative to today's standard) | 2nd Standard (relative to today's standard)

End Use	Technology	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Cooling	Central AC	SEER 13													
	Room AC	EER 9.8			EER 11.0										
	Evaporative Central AC	Conventional													
	Evaporative Room AC	Conventional													
Cooling/Heating	Heat Pump	SEER 13.0/HSPF 7.7				SEER 14.0/HSPF 8.0									
Space Heating	Electric Resistance	Electric Resistance													
Water Heating	Water Heater (<=55 gallons)	EF 0.90				EF 0.95									
	Water Heater (>55 gallons)	EF 0.90				Heat Pump Water Heater									
Lighting	Screw-in/Pin Lamps	Incandescent			Advanced Incandescent - tier 1						Advanced Incandescent - tier 2				
	Linear Fluorescent	T8													
Appliances	Refrigerator/2nd Refrigerator	NAECA Standard			25% more efficient										
	Freezer	NAECA Standard			25% more efficient										
	Dishwasher	Conventional (355		14% more efficient (307 kWh/yr)											
	Clothes Washer	Conventional (MEF 1.26 for top loader)				MEF 1.72 for top loader			MEF 2.0 for top loader						
	Clothes Dryer	Conventional (EF 3.01)				5% more efficient (EF 3.17)									
	Range/Oven	Conventional													
	Microwave	Conventional													
Electronics	Personal Computer	Conventional/Energy Star													
	Monitor	Conventional													
	Laptop Computer	Conventional/Energy Star													
	TV	Conventional/Energy Star													
	Copier/Printer/Fax	Conventional													
	DVD/VCR/Audio	Conventional													
	Devices and Gadgets	Conventional													
Miscellaneous	Pool Pump	Conventional													
	Well Pump	Conventional													
	Furnace Fan	Conventional													

Table 2-15 Residential Natural Gas Equipment Standards

End Use	Technology	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heating	Furnace	EF 0.90														
	Boiler	EF 0.80		EF 0.82												
	Supplemental Heat	AFUE 0.74														
Water Heating	Water Heater	EF 0.67														
Appliances	Clothes Dryer	Conventional														
	Range/Oven	Conventional														
Miscellaneous	Pool Heater	Conventional														
	Gas Barbeque	Conventional														

Table 2-16 Commercial Electric Equipment Standards

Today's Efficiency or Standard Assumption
1st Standard (relative to today's standard)
2nd Standard (relative to today's standard)

End Use	Technology	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cooling	Chillers	2007 ASHRAE 90.1														
	Roof Top Units	EER 11.0/11.2														
	Other Cooling	EER 9.8														
Space Heating	Electric Heating	Conventional														
Ventilation	Ventilation	Constant Air Volume/Variable Air Volume														
Lighting	Screw-in/Pin Lamps	Incandescent			Advanced Incandescent - tier 1						Advanced Incandescent - tier 2					
	Linear Fluorescent	T12	T8													
	High Intensity Discharge	Metal Halide														
Water Heating	Water Heater	EF 0.97														
Refrigeration	Walk-in Refrigerator/Freezer	EISA 2007 Standard														
	Reach-in Refrigerator	EPACT 2005 Standard														
	Glass Door Display	EPACT 2005 Standard														
	Open Display Case	EPACT 2005 Standard														
	Vending Machines	EPACT 2005 Standard														
	Icemaker	2010 Standard														
Office Equipment	Desktop Computer	Conventional/Energy Star														
	Laptop Computer	Conventional/Energy Star														
Miscellaneous	Non-HVAC Motors	62.3% Efficiency					70% Efficiency									

Table 2-17 Commercial Gas Equipment Standards

Today's Efficiency or Standard Assumption
1st Standard (relative to today's standard)
2nd Standard (relative to today's standard)

End Use	Technology	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heating	Furnace	AFUE 76%														
	Boiler	EF 0.76	EF 0.8			EF 0.84										
Water Heating	Water Heater	Conventional	EF 0.80						EF 0.92							
Miscellaneous	Pool Heater	Conventional														

Energy Efficiency Measure Data Application

Table 2-18 details the data sources used for measure characterization.

Table 2-18 Data Needs for the Measure Characteristics in LoadMAP

Model Inputs	Description	Key Sources
Energy Impacts	The annual reduction in consumption attributable to each specific measure. Savings were developed as a percentage of the energy end use that the measure affects.	Manitoba Hydro Measure Database BEST EPRI National Study DEEM DEER Other secondary sources
Peak Demand Impacts	Savings during the peak demand periods are specified for each measure. These impacts relate to the energy savings and depend on the extent to which each measure is coincident with the system peak.	Manitoba Hydro Measure Database BEST EnergyShape
Costs	Equipment Measures: Includes the full cost of purchasing and installing the equipment on a per-unit, per-square-foot, or per employee basis for the residential, commercial, and industrial sectors, respectively. Non-equipment measures: Existing buildings – full installed cost. New Construction - the costs may be either the full cost of the measure, or as appropriate, it may be the incremental cost of upgrading from a standard level to a higher efficiency level.	Manitoba Hydro Measure Database DEEM DEER Other secondary sources
Measure Lifetimes	Estimates derived from the technical data and secondary data sources that support the measure demand and energy savings analysis.	Manitoba Hydro Measure Database DEEM DEER Other secondary sources
Applicability	Estimate of the percentage of either dwellings in the residential sector or square feet/employment in the C&I sectors where the measure is applicable and where it is technically feasible to implement.	DEEM DEER Other secondary sources
On Market and Off Market Availability	Expressed as years for equipment measures to reflect when the equipment technology is available or no longer available in the market.	Natural Resources Canada, Office of Energy Efficiency Appliance, building codes, and standards analysis

Data Application for Cost-effectiveness Screening

To perform the cost-effectiveness screening, a number of economic assumptions were needed. All cost and benefit values were escalated for inflation at an annualized forecast GDP growth rate of 1.86%. Discount rates, line loss factors, avoided capacity, and avoided energy costs were provided by Manitoba Hydro. Administrative costs were assumed to be 10% of incremental costs for purposes of the measure level economic screen.

Achievable Potential Estimation

To estimate potentials, three sets of parameters were required to account for the decision making behavior of humans in the efficiency marketplace.

- **Adoption rates for non-equipment measures**. Equipment measures are installed when existing units fail. Non-equipment measures do not have this natural periodicity, so rather than installing all available non-equipment measures in the first year of the forecast (instantaneous potential), they are phased in according to adoption schedules that vary based on cost and complexity. The adoption rates used in this analysis take several factors into account to determine how quickly the market can absorb these measures. Typically, measures that cause disruption to the building, such as wall insulation in existing buildings, receive longer adoption curves, while those with drop-in installations, such as programmable thermostats in new buildings, receive shorter ones. High capital cost measures will also receive longer adoption curves than ones with low capital cost. These adoption rates are used within LoadMAP to generate the Technical and Economic potentials. In general, the rates align with the diffusion of similar equipment measures.
- **Achievable High adoption rates (MARs).** These factors are applied to Economic potential to estimate the upper bound: Achievable High. These estimate customer adoption of economic measures when delivered through efficiency programs under ideal market, implementation, and customer preference conditions. Information channels are assumed to be established and efficient for marketing, educating consumers, and coordinating with trade allies and delivery partners. The Achievable High adoption rates are based on the ramp rates from the Northwest Power & Conservation Council's Sixth Plan as a starting point. The NWPCC has been running programs in the Pacific Northwest for many years, and the portfolio of programs reflects a similar profile of market maturity. Achievable High potential establishes a maximum target for the EE savings that an administrator can hope to achieve through its EE programs and involves incentives that represent a substantial portion of the incremental cost combined with high administrative and marketing costs.
- **Achievable Low adoption rates (PIFs).** These factors are applied to Achievable High potential to calculate Achievable Low potential, decrementing them by a range of 40% to 75% based on where measures lie in the time horizon of the study or whether they are already familiar inclusions in existing programs. These rates reflect expected program participation given significant barriers to customer acceptance, non-ideal implementation conditions, and limited program budgets. This represents a lower bound on achievable potential

MARs and PIFs are presented in Appendix E.

CHAPTER | 3

MARKET CHARACTERIZATION AND MARKET PROFILES

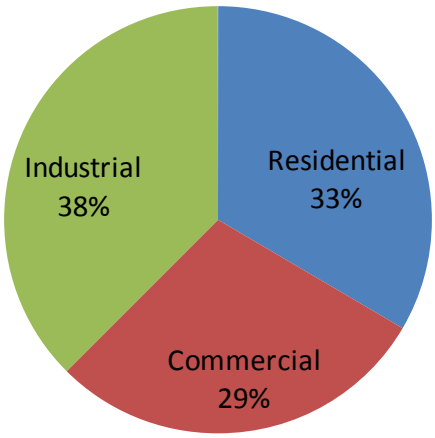
In this section, we describe how customers in Manitoba use electricity and natural gas in the base year of the study, 2010/11. It begins with a high-level summary of energy use by sector and then delves into each sector in detail.

Energy Use Summary

Manitoba Hydro is one of the largest electric and natural gas distribution utilities in Canada. It serves approximately 537,000 electric customers throughout Manitoba and 265,000 natural gas customers in Southern Manitoba. The utility had a total net income of $150 million for the 2010-11 fiscal year.9 The top industries in the service territory are chemical products, primary metals, petroleum, and food products.

Total electricity use for the residential, commercial and industrial sectors for Manitoba Hydro in 2010/11 was 20,213 GWh.[10] As shown in Figure 3-1, the largest sector is industrial, accounting for 38%, or 7,576 GWh. The remaining use is split between the residential and commercial and sectors, at 6,952 GWh and 5,685 GWh respectively.

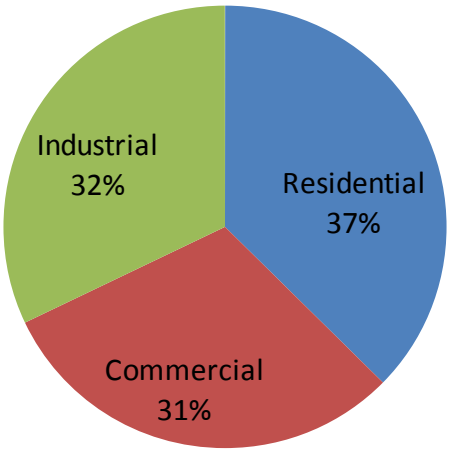
Figure 3-1 Sector-Level Electricity Use, 2010/11



Total gas use for the residential, commercial and industrial sectors in 2010 was 1,585 MMm3. As shown in Figure 3-2, the largest sector is residential, accounting for 37%, or 590 MMm3. The remaining use is closely split between the industrial (32%) and commercial (31%) sectors, at 509 MMm3 and 486 MMm3 respectively.

[9] http://www.hydro.mb.ca/corporate/ar/2010/publish/index.html#/12/
[10] Energy given "at-the-meter," i.e. does not include line losses.

Figure 3-2 Sector-Level Gas Use, 2010/11



Residential Sector

This section characterizes the residential market at a high level, and then provides a profile of how customers in each segment use electricity and gas by end use. The customer information for electricity will be presented first, followed by the gas information.

Electricity Use

Total residential electricity use in 2010/11 was 6,952 GWh. Customer information for each segment are shown in

Table 3-1, , Figure 3-3, and Figure 3-4.The single-family segment as a whole used the vast majority (89%) of the total residential sector electricity in 2010/11 as a result of the largest number of customers. The largest individual segment was the single family, gas heat, pre-2000, non-low income segment which comprised approximately 26% of the total usage. This segment also has the largest number of customers (35%).

Table 3-1 Residential Sector Electricity Usage by Segment Type

Segment Name	Home Type	Heating	Geographic location	Vintage	Income	Ave. Elec Custs	Elec Use (GWh)
SFGasPre-2000	SF	GasHeat	GasAvailable	Pre-2000	Non-LowIncome	155,115	1,802
SFGas2000+	SF	GasHeat	GasAvailable	2000-present	Non-LowIncome	15,235	239
SFGasPre-2000LI	SF	GasHeat	GasAvailable	Pre-2000	LowIncome	42,779	359
SFGas2000+LI	SF	GasHeat	GasAvailable	2000-present	LowIncome	566	7
SFElecGAPre-2000	SF	ElectricHeat	GasAvailable	Pre-2000	Non-LowIncome	39,441	1,145
SFElecGA2000+	SF	ElectricHeat	GasAvailable	2000-present	Non-LowIncome	7,312	226
SFElecGAPre-2000LI	SF	ElectricHeat	GasAvailable	Pre-2000	LowIncome	10,279	253
SFElecGA2000+LI	SF	ElectricHeat	GasAvailable	2000-present	LowIncome	1,329	32
SFElecSNGPre-2000	SF	ElectricHeat	SouthNoGas	Pre-2000	Non-LowIncome	32,608	966
SFElecSNG2000+	SF	ElectricHeat	SouthNoGas	2000-present	Non-LowIncome	4,293	145
SFElecSNGPre-2000LI	SF	ElectricHeat	SouthNoGas	Pre-2000	LowIncome	9,801	233
SFElecSNG2000+LI	SF	ElectricHeat	SouthNoGas	2000-present	LowIncome	643	13
SFElecNNGPre-2000	SF	ElectricHeat	NorthNoGas	Pre-2000	Non-LowIncome	6,038	171
SFElecNNG2000+	SF	ElectricHeat	NorthNoGas	2000-present	Non-LowIncome	522	15
SFElecNNGPre-2000LI	SF	ElectricHeat	NorthNoGas	Pre-2000	LowIncome	1,099	32
SFElecNNG2000+LI	SF	ElectricHeat	NorthNoGas	2000-present	LowIncome	70	2
SFElecNGReserve	SF	ElectricHeat	ReserveNoGas	All	All	15,136	468
SFOthAll	SF	Other	All	All	All	10,921	184
MFGas	MF	GasHeat	All	All	Non-LowIncome	13,232	124
MFGasLI	MF	GasHeat	All	All	LowIncome	6,806	48
MFElec	MF	ElectricHeat	All	All	Non-LowIncome	5,679	94
MFElecLI	MF	ElectricHeat	All	All	LowIncome	2,418	38
MFElecNGReserve	MF	ElectricHeat	ReserveNoGas	All	All	722	19
MFOthAll	MF	Other	All	All	All	4,901	31
AptGas	Apt	GasHeat	All	All	Non-LowIncome	1,358	8
AptGasLI	Apt	GasHeat	All	All	LowIncome	1,090	5
AptElec	Apt	ElectricHeat	All	All	Non-LowIncome	12,738	129
AptElecLI+	Apt	ElectricHeat	All	All	LowIncome	7,885	57
AptOthAll	Apt	Other	All	All	All	33,604	111
Total						**443,618**	**6,952**

Figure 3-3 Residential Electric Customers by Segment, 2010-2011 (% of customers)

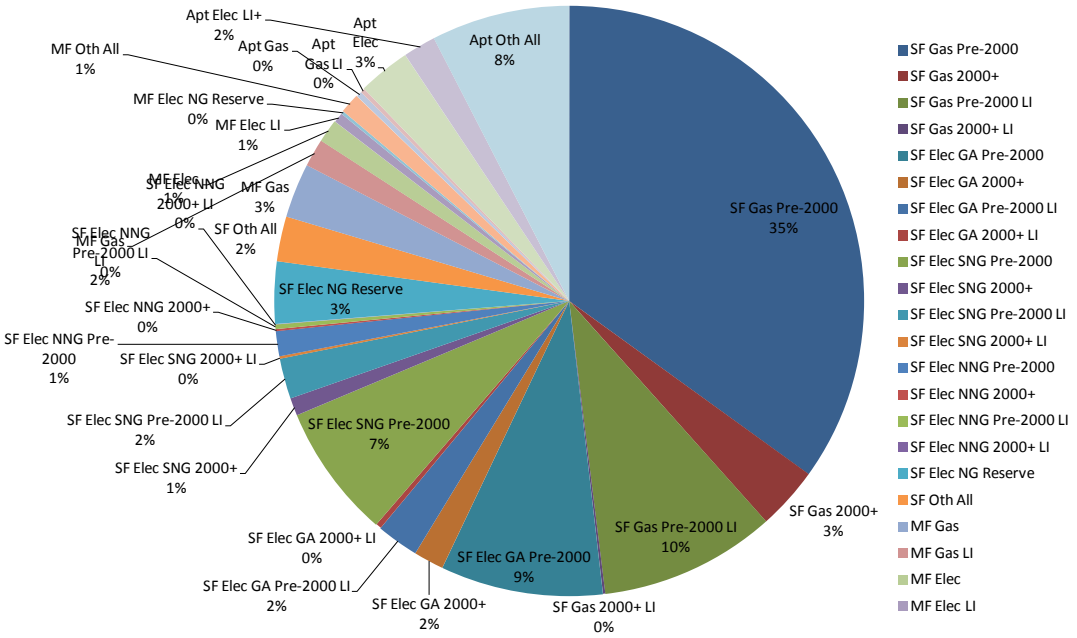
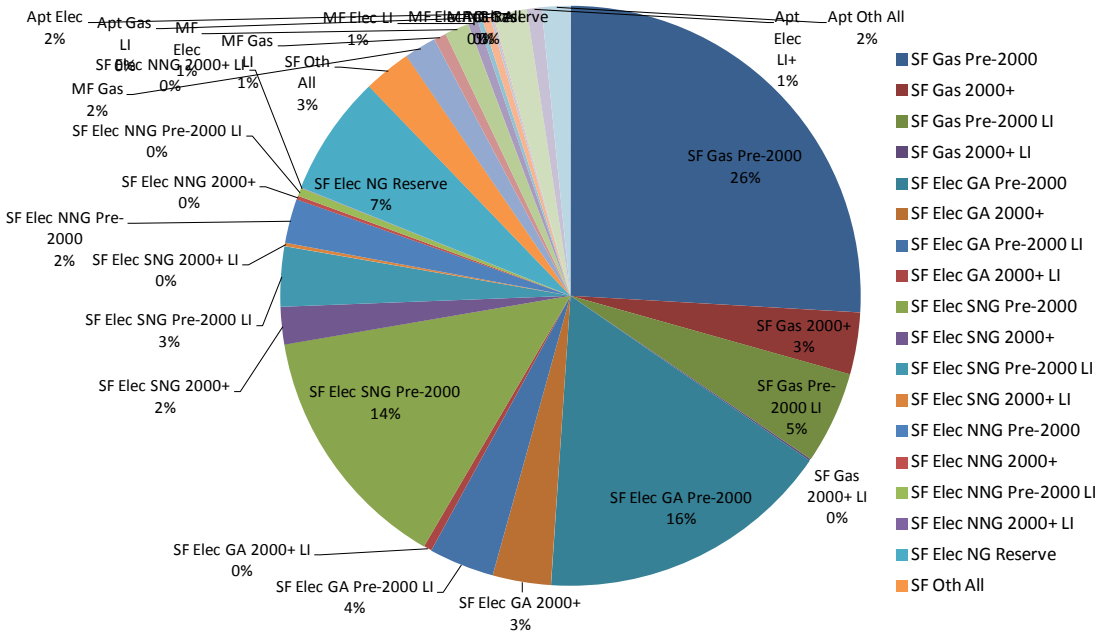


Figure 3-4 Residential Electric Use by Segment, 2010-2011 (% of electricity sales)



As we describe in the previous chapter, the market profiles provide the foundation upon which we develop the baseline forecast. The electric market profile for the residential sector as a whole is presented in Table 3-2. The residential market profiles for each housing segment are presented in Appendix A.

Table 3-2 Electric Market Profile for the Residential Sector

Average Market Profiles

End Use	Technology	Saturation	UEC (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	59.6%	922	550	244
Cooling	Room AC	18.6%	391	73	32
Cooling	Geothermal Heat Pump	1.6%	205	3	1
Cooling	Evaporative Central AC	0.0%	307	0	0
Space Heating	Electric Resistance	12.7%	11,502	1,461	648
Space Heating	Electric Furnace	18.9%	14,621	2,760	1,225
Space Heating	Electric Boiler	1.3%	11,462	147	65
Space Heating	Geothermal Heat Pump	1.6%	9,254	151	67
Space Heating	Supplemental Heat	27.3%	621	170	75
HVAC Other	Central Exhaust	10.3%	344	35	16
HVAC Other	Electronic Air Cleaner	9.8%	1,080	105	47
HVAC Other	Humidifier	18.2%	519	94	42
HVAC Other	Dehumidifier	29.5%	502	148	66
Water Heating	Water Heater	45.2%	3,341	1,510	670
Water Heating	Water Heater - Tankless	0.2%	2,517	4	2
Interior Lighting	Screw-in	100.0%	887	887	394
Interior Lighting	Linear Fluorescent	66.9%	101	68	30
Exterior Lighting	Screw-in	100.0%	206	206	91
Appliances	Clothes Washer	86.7%	391	339	150
Appliances	Clothes Dryer	82.9%	838	695	308
Appliances	Dishwasher	65.7%	305	200	89
Appliances	Refrigerator	99.8%	802	800	355
Appliances	Freezer	78.4%	672	527	234
Appliances	Second Refrigerator	43.2%	1,226	529	235
Appliances	Second Freezer	17.8%	824	147	65
Appliances	Stove	95.0%	613	582	258
Appliances	Microwave	95.5%	92	88	39
Electronics	Personal Computers	77.0%	302	233	103
Electronics	Monitor	77.0%	56	43	19
Electronics	Laptops	43.2%	85	37	16
Electronics	TVs	190.8%	194	371	165
Electronics	Printer/Fax/Copier	84.0%	41	35	15
Electronics	Set-top Boxes/DVR	134.7%	323	435	193
Miscellaneous	Pool Pump	3.2%	2,779	88	39
Miscellaneous	Pool Heater	0.6%	11,208	70	31
Miscellaneous	Hot Tub / Spa	10.2%	1,931	197	87
Miscellaneous	Well Pump	12.4%	551	69	30
Miscellaneous	Furnace Fan	75.1%	1,225	920	408
Miscellaneous	Sewage Pump	9.8%	39	4	2
Miscellaneous	Sump Pump	14.1%	48	7	3
Miscellaneous	Pressure Pump	10.2%	776	79	35
Miscellaneous	Sauna	1.7%	2,456	41	18
Miscellaneous	Car Block Heaters	71.7%	135	97	43
Miscellaneous	Car Warmers	6.7%	237	16	7
Miscellaneous	Electric Vehicles	0.0%	1,707	0	0
Miscellaneous	Miscellaneous	100.0%	650	650	289
	Total			**15,671**	**6,952**

Figure 3-5 presents the electric end-use breakout for the residential sector as a whole. Space conditioning—including heating, cooling and HVAC other — accounts for over a third of total energy use. Appliances and miscellaneous are the next largest uses, with 25% and 14% of total energy use,

respectively. Water heating, lighting, and electronics (personal computers, televisions, video game consoles, etc.), make up the remaining use. Note that the miscellaneous end use includes furnace fans, pool pumps, well pumps, car block heaters, and other "plug" loads (hair dryers, power tools, coffee makers, toaster ovens, etc.).

Figure 3-5 Residential Electricity Use by End Use, 2010/11

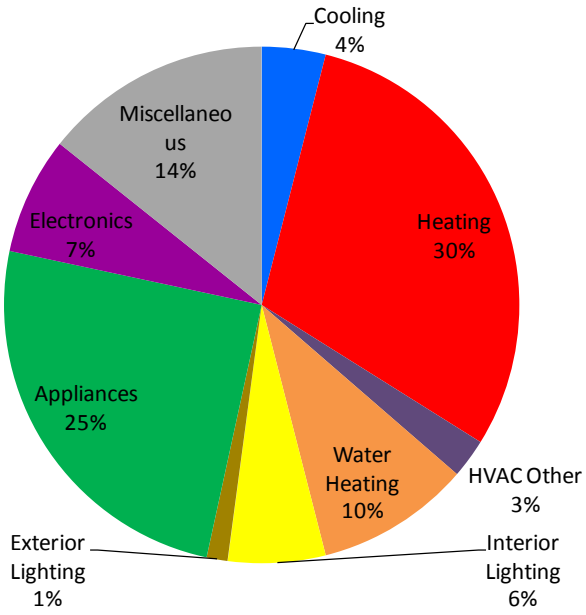
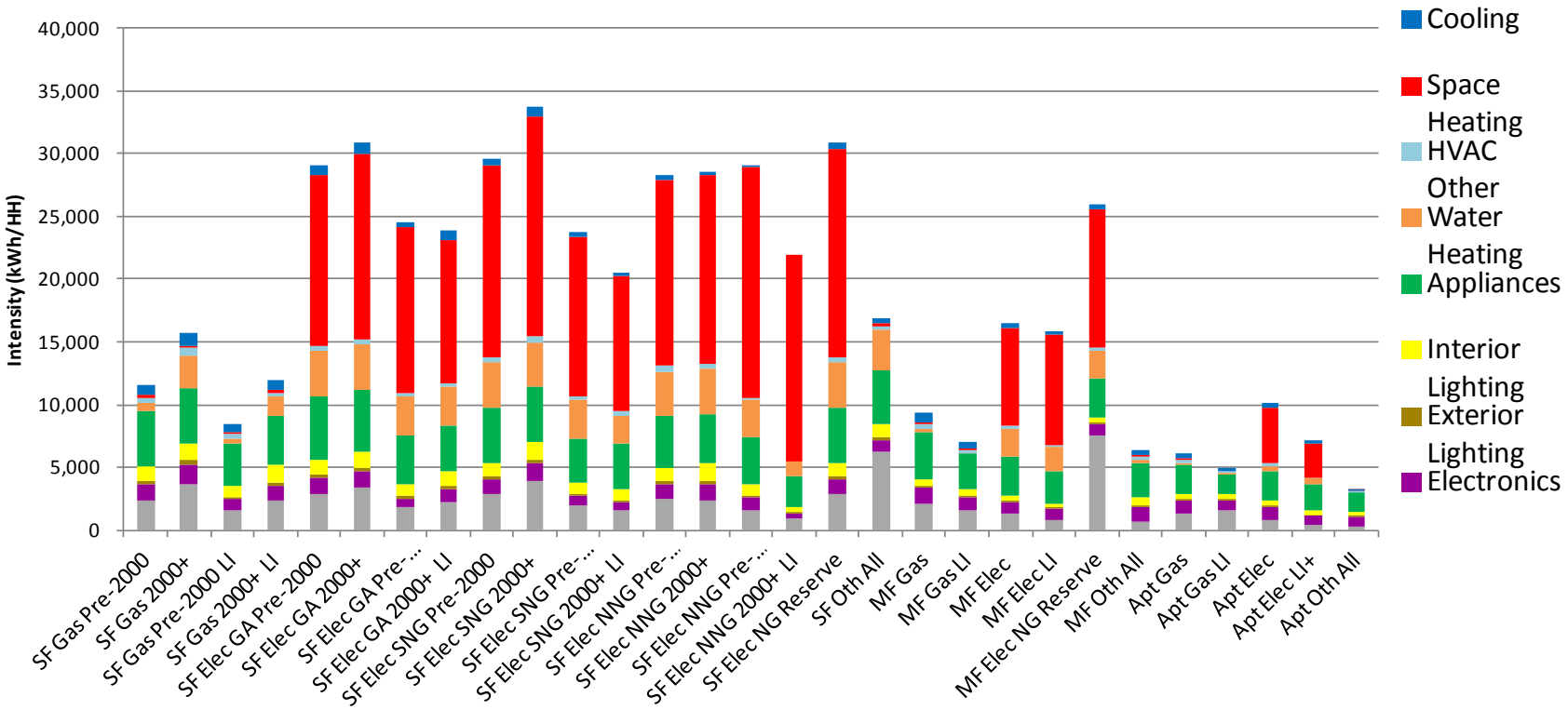


Figure 3-6 presents the end-use shares of residential electricity use for each housing type. Most end uses other than space conditioning have a fairly constant share across segments.

Figure 3-6 End-Use Shares of Total Electricity Use by Housing Type, 2010/11



Natural Gas Use

Total residential gas use in 2010/11 was 590 MMm3. Information for each customer segment is shown in Table 3-3, Figure 3-7, and Figure 3-8. Similar to electricity, the single-family segment as a whole used the vast majority (over 90%) of the total residential sector natural gas in 2010-2011 as a result of the largest number of customers.

Table 3-3 Residential Sector Gas Usage by Segment Type

Segment Name	Home Type	Heating	Geographic location	Vintage	Income	Ave. Natural Gas Cust	Natural Gas Use (MMm3)
SFGasPre-2000	SF	Gas Heat	Gas Available	Pre-2000	Non-Low Income	155,115	402.58
SFGas2000+	SF	Gas Heat	Gas Available	2000-present	Non-Low Income	15,235	32.99
SFGasPre-2000LI	SF	Gas Heat	Gas Available	Pre-2000	Low Income	42,779	104.24
SFGas2000+LI	**SF**	Gas Heat	Gas Available	2000-present	Low Income	566	1.61
SFElecGAPre-2000	SF	Electric Heat	Gas Available	Pre-2000	Non-Low Income	39,441	3.49
SFElecGA2000+	SF	Electric Heat	Gas Available	2000-present	Non-Low Income	7,312	0.41
SFElecGAPre-2000LI	SF	Electric Heat	Gas Available	Pre-2000	Low Income	10,279	0.95
SFOthAll	SF	Other	All	All	All	10,921	1.15
MFGas	MF	Gas Heat	All	All	Non-Low Income	13,232	26.03
MFGasLI	MF	Gas Heat	All	All	Low Income	6,806	14.25
MFElec	MF	Electric Heat	All	All	Non-Low Income	5,679	0.01
MFOthAll	MF	Other	All	All	All	4,901	0.77
AptGas	Apt	Gas Heat	All	All	Non-Low Income	1,358	1.04
AptGasLI	Apt	Gas Heat	All	All	Low Income	1,090	0.64
Total						**314,713**	**590.14**

Figure 3-7 Residential Natural Gas Customers by Segment, 2010/11 (% of customers)

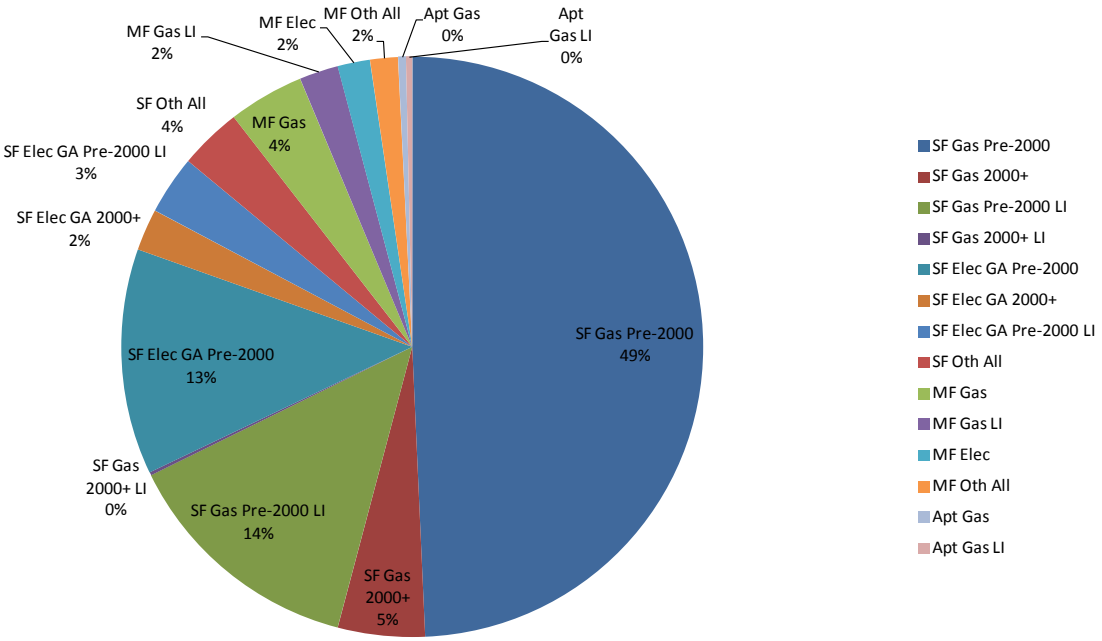
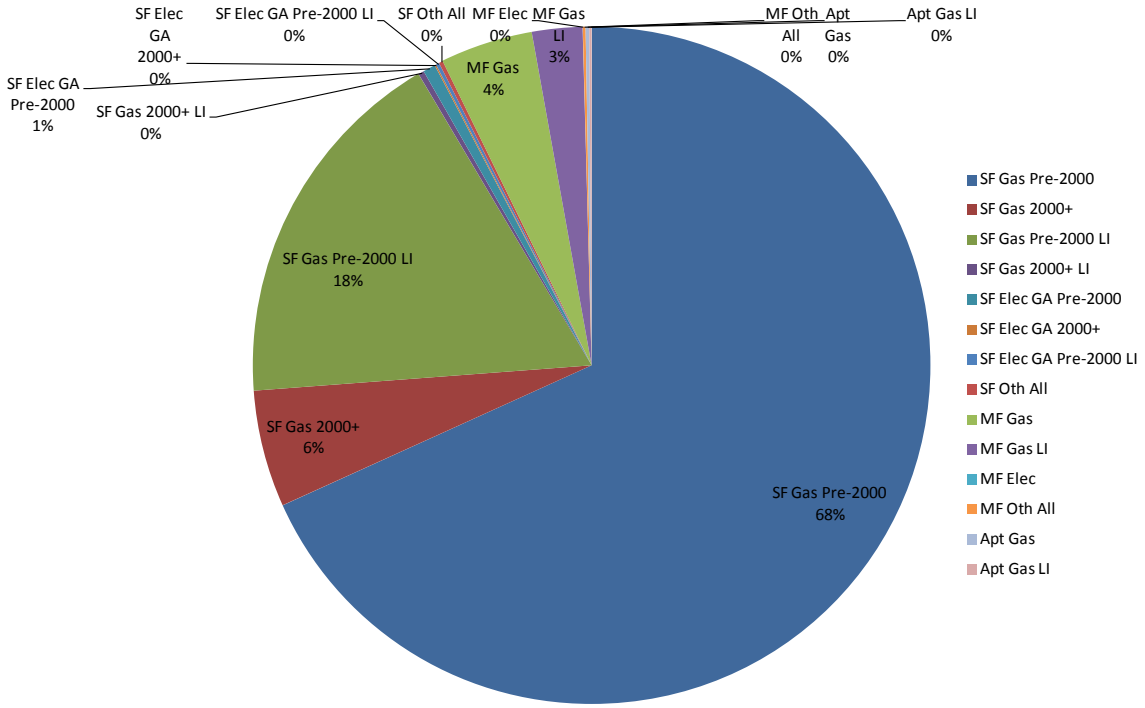


Figure 3-8 Residential Natural Gas Use by Segment, 2010/11 (% of gas sales)



The natural gas market profile for the residential sector as a whole is presented in Table 3-4. The residential market profiles for each housing segment are presented in Appendix A.

Table 3-4 Natural Gas Market Profile for the Residential Sector

Average Market Profiles

End Use	Technology	Saturation	UEC (m3)	Intensity (m3/HH)	Usage (MMm3)
Space Heating	Gas Furnace	72.0%	1,896	1,365	429.6
Space Heating	Gas Boiler	3.0%	3,618	109	34.4
Space Heating	Supplemental Heat	8.1%	390	32	9.9
Water Heating	Water Heater	59.2%	502	297	93.5
Appliances	Clothes Dryer	5.3%	178	9	2.9
Appliances	Stove	4.8%	274	13	4.1
Miscellaneous	Pool Heater	2.4%	1,539	37	11.7
Miscellaneous	Gas Barbeque	2.9%	127	4	1.2
Miscellaneous	Miscellaneous	87.5%	10	9	2.7
	Total			**1,875**	**590.1**

Figure 3-9 presents the natural gas end-use breakout for the residential sector as a whole. The space heating end use accounts for over three-quarters of total natural gas use. Water heating is the next largest use with 16% of total natural gas use. Appliances and miscellaneous (pool heaters, gas barbeque grills, farming equipment, etc.) make up the remaining use totaling to just under 5%.

Figure 3-10 presents the end-use shares of residential natural gas use for each housing type

Figure 3-9 Residential Natural Gas Use by End Use, 2010/11

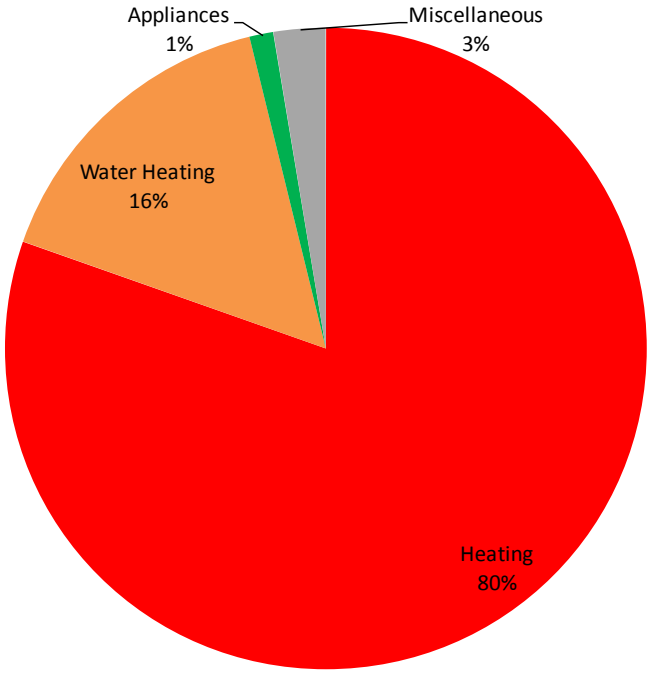
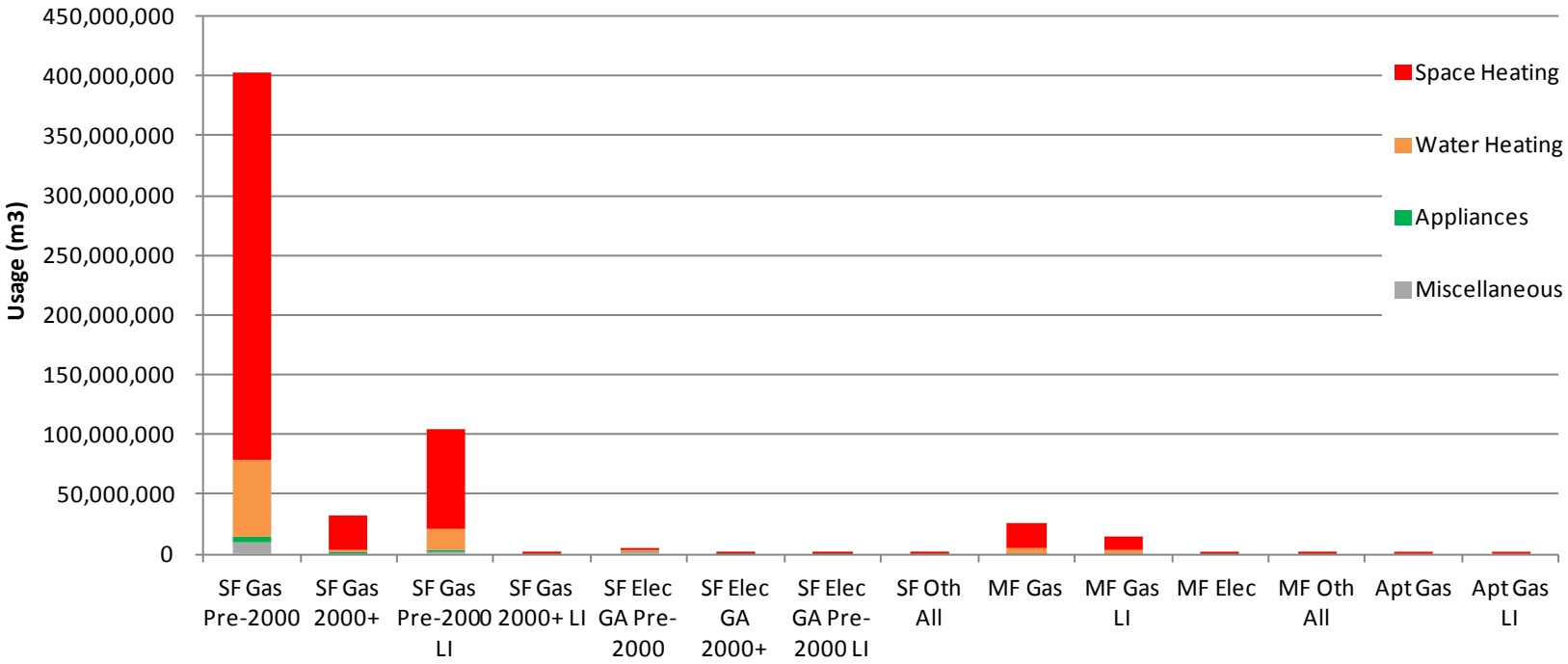


Figure 3-10 End-Use Shares of Total Natural Gas Use by Housing Type, 2010/11



Commercial Sector

This section characterizes the commercial market at the segment level, and then provides a profile of how each segment uses electricity and natural gas by end use.

Electricity Use

Total electricity use in the commercial sector in 2010/11 was 5,685 GWh. Manitoba Hydro provided estimates of floor space for each of the segments. Floor space is used to normalize energy use and develop intensity in terms of GWh per square foot of floor space. Total commercial floor space is estimated at 388 million square feet, implying an average intensity of 14.6 kWh per square foot per year.

Table 3-5 presents the floor space, intensity estimates, and annual electricity use for each building type. The largest segments by energy usage are large office, large retail, and bulk apartments. The largest segments by floor space are bulk apartments and services. Groceries and restaurants have the highest intensity due to the large amount of refrigeration and cooking. Small warehouses, small education and services have the lowest intensities.

Table 3-5 Commercial Sector Electric Market Characterization Results, 2010/11

Segment	Floor Space (MSqFt)	Intensity (GWh/sq ft)	Sales (GWh)
Large Office	31.9	18.9	603.4
Small Office	25.3	14.7	372.8
Restaurant	7.7	40.9	315.8
Large Retail	21.9	27.2	595.2
Small Retail	30.1	11.5	344.6
Grocery	7.7	41.4	319.2
Large Warehouse	15.7	17.9	280.7
Small Warehouse	23.6	6.9	162.9
Large Education	19.6	10.4	203.0
Small Education	17.3	8.4	144.8
Large Health	13.6	21.5	290.9
Small Health	3.4	12.2	41.4
Lodging	18.5	17.1	315.2
Bulk apartments	41.3	13.1	541.2
Services	37.1	8.1	301.1
Large Recreation Facility	15.9	17.9	284.6
Small Recreation Facility	17.8	10.1	180.0
Large Miscellaneous	5.4	10.2	54.6
Small Miscellaneous	34.8	9.6	333.6
Total	**388.4**	**14.6**	**5,684.9**

Table 3-6 shows the electric market profile for the commercial sector as a whole, representing a composite of all the building types. Overall, about 77% of commercial electric floor space is cooled. About 19% of commercial electric floor space is heated using electric equipment, either some form of resistance heating or heat pumps. Linear fluorescent lighting is the largest single energy-consuming technology in the commercial sector, closely followed by screw-in lamps. Roof top AC, ventilation, high intensity discharge lighting are the next largest uses. Market profiles for each building type are presented in Appendix A.

Table 3-6 Commercial Sector Composite Electric Market Profile, 2010

Average Market Profiles

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	3.7%	5.93	0.22	85.1
Cooling	Water-Cooled Chiller	12.4%	5.50	0.68	265.1
Cooling	Roof top AC	36.5%	4.04	1.47	572.6
Cooling	Roof top Heat Pump	6.7%	3.76	0.25	98.0
Cooling	Other Cooling	17.9%	2.75	0.49	190.9
Heating	Roof top Heat Pump	6.7%	4.66	0.31	121.4
Heating	Electric Heating	12.0%	5.15	0.62	240.6
Ventilation	Ventilation	100.0%	1.10	1.10	429.0
Water Heating	Water Heating	40.8%	1.59	0.65	252.4
Interior Lighting	Screw-in	64.2%	2.91	1.87	725.2
Interior Lighting	High-Bay Fixtures	38.0%	1.02	0.39	149.7
Interior Lighting	Linear Fluorescent	89.7%	2.47	2.21	859.1
Exterior Lighting	Screw-in	17.5%	0.62	0.11	42.1
Exterior Lighting	HID	61.1%	1.16	0.71	275.3
Exterior Lighting	Linear Fluorescent	29.0%	0.17	0.05	19.2
Refrigeration	Walk-in Refrigerator	25.7%	1.35	0.35	135.4
Refrigeration	Reach-in Refrigerator	10.1%	0.22	0.02	8.6
Refrigeration	Glass Door Display	31.3%	1.50	0.47	181.9
Refrigeration	Open Display Case	6.7%	1.05	0.07	27.3
Refrigeration	Icemaker	19.9%	0.25	0.05	19.5
Refrigeration	Vending Machine	2.8%	0.25	0.01	2.7
Food Preparation	Oven	18.3%	0.30	0.06	21.6
Food Preparation	Fryer	18.3%	0.40	0.07	28.6
Food Preparation	Dishwasher	27.0%	0.49	0.13	51.5
Food Preparation	Hot Food Container	18.3%	0.14	0.03	9.7
Office Equipment	Desktop Computer	84.7%	0.74	0.62	242.1
Office Equipment	Laptop	84.7%	0.11	0.09	35.4
Office Equipment	Server	31.9%	0.40	0.13	49.8
Office Equipment	Monitor	84.7%	0.14	0.12	44.9
Office Equipment	Printer/Copier/Fax	77.0%	0.11	0.08	31.8
Office Equipment	POS Terminal	35.7%	0.08	0.03	11.6
Misc	Non-HVAC Motors	55.1%	1.07	0.59	228.5
Misc	Pool Pump	3.9%	0.04	0.00	0.5
Misc	Pool Heater	1.0%	0.06	0.00	0.2
Misc	Misc	100.0%	0.59	0.59	227.3
Total				**14.64**	**5,684.9**

Figure 3-11 shows the breakdown of annual commercial electricity usage by end use. Space conditioning (cooling, heating and ventilation) and lighting (interior and exterior) are the largest end uses, consuming 35% and 37% of commercial building energy use, respectively.

Figure 3-11 Commercial Electricity Use by End Use, 2010-2011

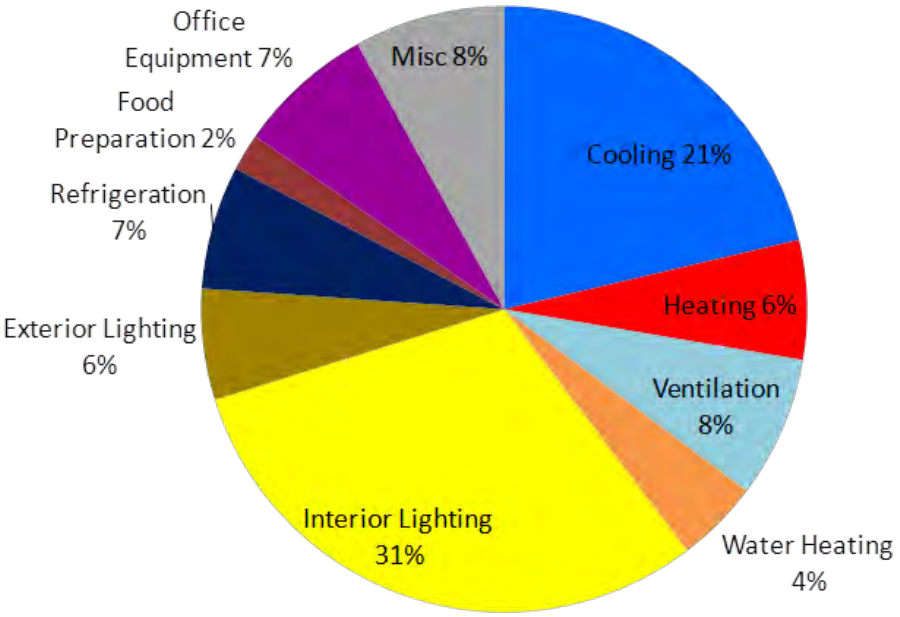
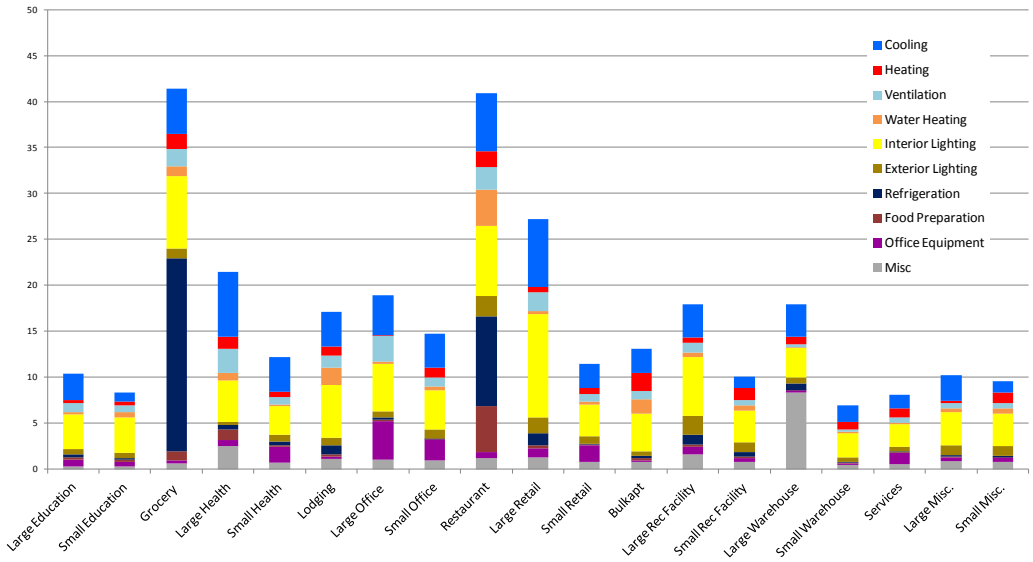


Figure 3-12 illustrates how the end-use composition of electricity use varies by building type. Observations include the following:

- Lighting and cooling are major end uses across all building types
- Refrigeration has a large share in grocery stores and restaurants
- Office equipment has substantial use in large offices, small offices, small retail, and services.
- Miscellaneous is highest in large warehouse and large health since this end use includes grain elevators and medical equipment, respectively.

Figure 3-12 Commercial End Use Electric Intensities by Building Type, 2010-2011



Natural Gas Use

Total commercial natural gas use in 2010/11 was 486 MMm3. Table 3-7 presents the floor space, intensity estimates, and annual gas use for each building type. The three largest segments by intensity are large miscellaneous, restaurant, and large health. The three largest segments by sales are large office, large health, and services.

Table 3-7 Commercial Sector Gas Market Characterization Results, 2010/11

Segment	Floor Space (MSqFt)	Intensity (m3/sq ft)	Sales (MMm3)
Large Office	31.9	2.0	64.1
Small Office	20.4	1.2	23.6
Restaurant	6.1	4.4	26.6
Large Retail	21.9	1.5	32.1
Small Retail	22.9	1.2	26.9
Grocery	4.1	1.1	4.7
Large Warehouse	14.8	1.2	17.6
Small Warehouse	20.9	1.0	21.1
Large Education	16.6	1.5	24.6
Small Education	14.5	1.3	19.4
Large Health	12.4	3.2	39.4
Small Health	3.1	2.4	7.7
Lodging	15.8	1.2	18.2
Bulk apartments	31.8	0.8	24.0
Services	29.2	1.3	37.7
Large Recreation Facility	14.8	2.0	29.2
Small Recreation Facility	11.6	0.8	8.8
Large Miscellaneous	5.4	5.6	30.1
Small Miscellaneous	23.9	1.3	30.2
Total	**322.0**	**1.5**	**485.9**

Table 3-8 shows the natural gas market profile for the commercial sector as a whole, representing a composite of all the building types. Overall, about 86% of commercial natural gas floor space is heated. Furnaces are the largest single energy-consuming technology in the commercial sector, followed by boilers, and water heating.

Market profiles for each building type are presented in Appendix A. Note that for modeling purposes in the natural gas analysis, LoadMAP requires total floor space (i.e. electric square footage) instead of gas square footage to normalize energy use. Therefore, the inputs to LoadMAP were adjusted and calibrated to reflect total square footage instead of gas square footage (as shown in Appendix A). The total energy usage for each segment corresponds to the values in Table 3-7.

Table 3-8 Commercial Sector Composite Natural Gas Market Profile, 2010/11

Average Market Profiles

End Use	Technology	Saturation	EUI (m3)	Intensity (m3/Sqft)	Usage (MMm3)
Heating	Furnace	72.1%	1.10	0.79	255.2
Heating	Boiler	14.7%	2.24	0.33	105.9
Water Heating	Water Heating	55.1%	0.48	0.26	84.6
Cooking	Oven	14.3%	0.07	0.01	3.4
Cooking	Fryer	14.3%	0.09	0.01	4.3
Cooking	Broiler	14.3%	0.09	0.01	4.3
Cooking	Griddle	14.3%	0.07	0.01	3.2
Cooking	Range	14.3%	0.08	0.01	3.8
Cooking	Steamer	14.3%	0.12	0.02	5.3
Misc	Pool Heater	1.2%	0.16	0.00	0.6
Misc	Misc	10.7%	0.45	0.05	15.3
	Total			**1.51**	**485.9**

Figure 3-13 illustrates the overall natural gas use by end use in the commercial sector as a whole. Space heating and water heating are the largest end uses, consuming 74% and 18% of commercial building natural gas use, respectively.

Figure 3-13 Commercial Natural Gas Use by End Use, 2010-2011

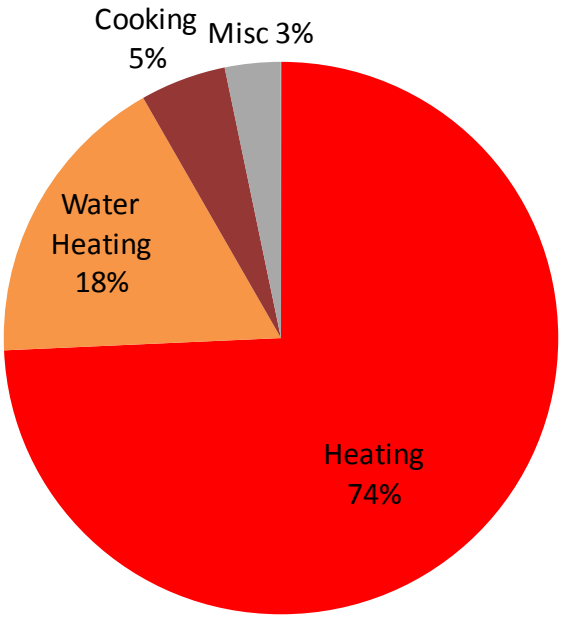
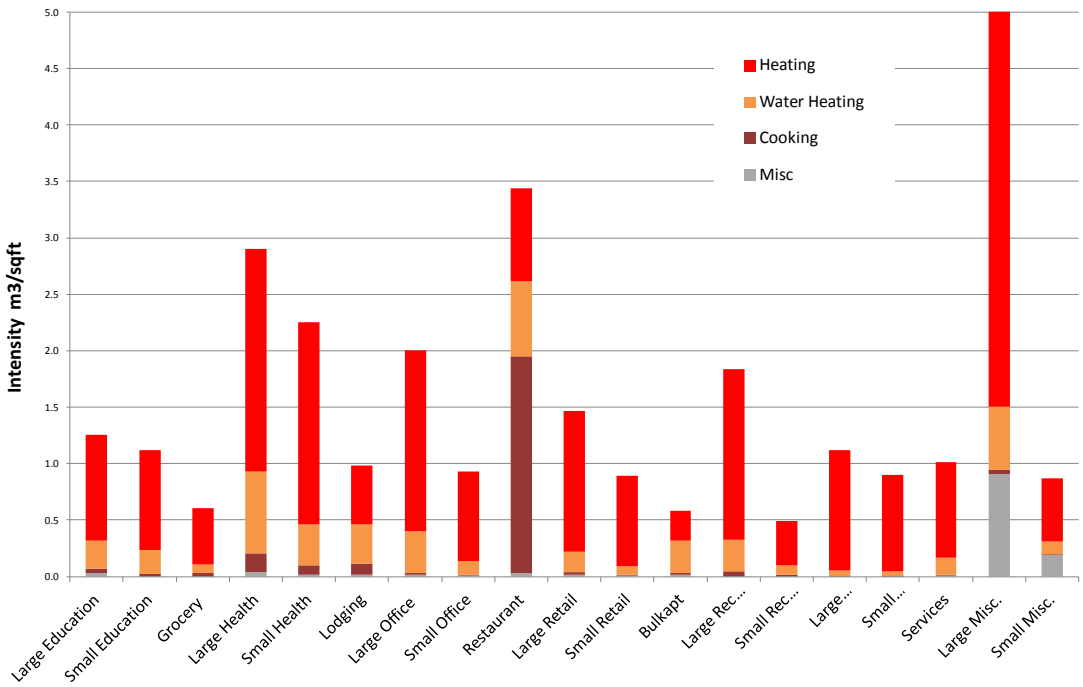


Figure 3-14 illustrates how the end-use composition of gas use varies by building type. Heating is the major end use across all building types. Cooking is a substantial use in restaurants.

Figure 3-14 Commercial End Use Gas Intensities by Building Type, 2010-2011



Industrial Sector

This section characterizes the industrial market at the segment level, and then provides a profile of how each segment uses electricity and natural gas by end use.

Electricity Use

The industrial sector, at 7,576 GWh in 2010/11, accounts for over one-third of total electricity sales. Table 3-9 presents the number of employees, intensity estimates, and annual electric use for each segment. Chemicals and primary metals are the two largest industries accounting for 58% of total industrial sales in 2010/11.

Table 3-9 Industrial Sector Electric Market Characterization Results, 2010/11

Segment	Employees	Intensity (kWh/emp)	Sales (GWh)
Mining	247	561,538	138
Food and Beverage	7,303	62,875	459
Pulp and Paper	1,760	164,545	290
Chemical	359	6,196,865	2,224
Petroleum	69	11,323,529	781
Primary Metals	3,844	561,538	2,159
Misc. Industrial	775	592,262	459
Other Agriculture	5,414	113,710	616
Other Industrial	3,962	113,710	451
Total	**23,734**	**319,215**	**7,576**

As with the residential and commercial sectors, the industrial market profiles characterize electricity use in terms of end use and technology for the base year 2010/11. Table 3-10 shows the composite market profiles for the industrial sector.

Market profiles for each segment are presented in Appendix A

Table 3-10 Industrial Composite Electric Market Profile, 2010/11

Average Market Profiles			
End Use	**Technology**	**Usage (GWh)**	**Intensity (kWh/Employee)**
Cooling	Air-Cooled Chiller	23.2	978
Cooling	Water-Cooled Chiller	69.8	2,941
Cooling	Roof top AC	238.5	10,048
Cooling	Other Cooling	17.4	732
Heating	Electric Heating	77.5	3,267
Ventilation	Ventilation	30.5	1,283
Interior Lighting	Screw-in	41.4	1,745
Interior Lighting	High-Bay Fixtures	24.1	1,013
Interior Lighting	Linear Fluorescent	382.8	16,129
Exterior Lighting	Screw-in	0.0	0
Exterior Lighting	HID	83.6	3,521
Exterior Lighting	Linear Fluorescent	0.0	0
Pumps	Pumps	431.4	18,176
Fans & Blowers	Fans & Blowers	337.7	14,228
Compressed Air	Compressed Air	269.6	11,360
Conveyors	Conveyors	371.3	15,643
Other Motors	Other Motors	1,313.7	55,352
Process Heating	Process Heating	1,287.7	54,254
Process Cooling and Refrigeration	Process Cooling and Refrigeratic	361.0	15,212
Electro-Chemical Processes	Electro-Chemical Processes	1,861.2	78,417
Other Process	Other Process	116.1	4,892
Misc	Misc	237.9	10,024
	Total	**7,576.3**	**319,215**

Figure 3-15 presents the end-use breakout for the industrial sector in 2010/11. The machine drive end use is the largest overall for the industrial sector, accounting for 35% of energy use. Note that a wide range of industrial equipment, such as air compressors and refrigeration compressors, pumps, and fans are included within the machine drive category. Electro-chemical process and process heating account for 25% and 17% of energy use, respectively. Lighting, heating, ventilation, and cooling, process cooling, and miscellaneous are all under 10%.

Figure 3-15 Industrial Electricity Use by End Use, 2010/11

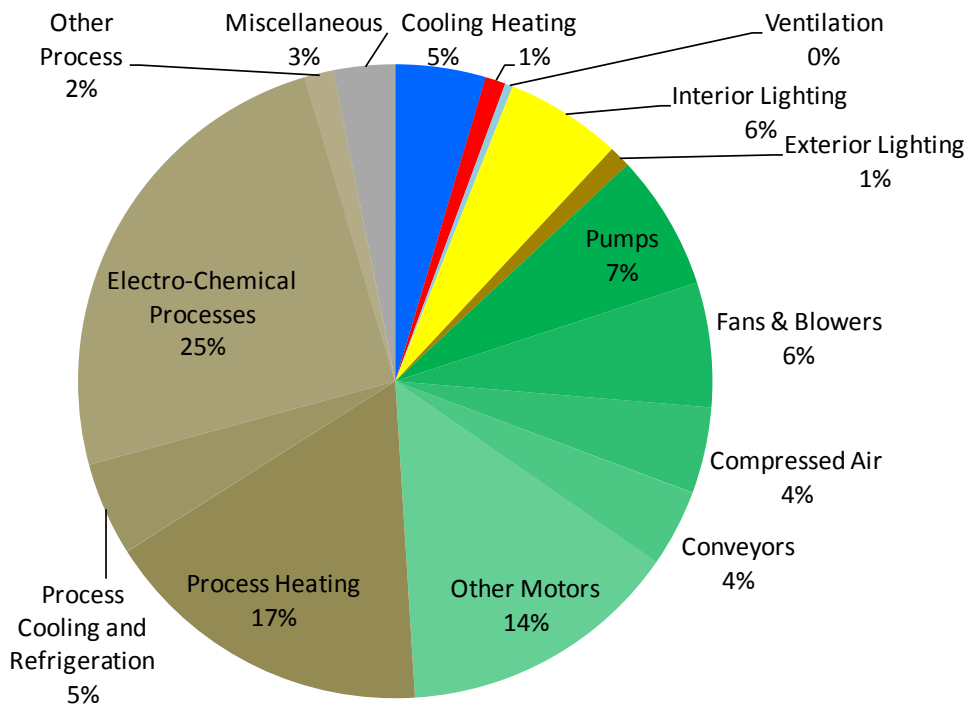
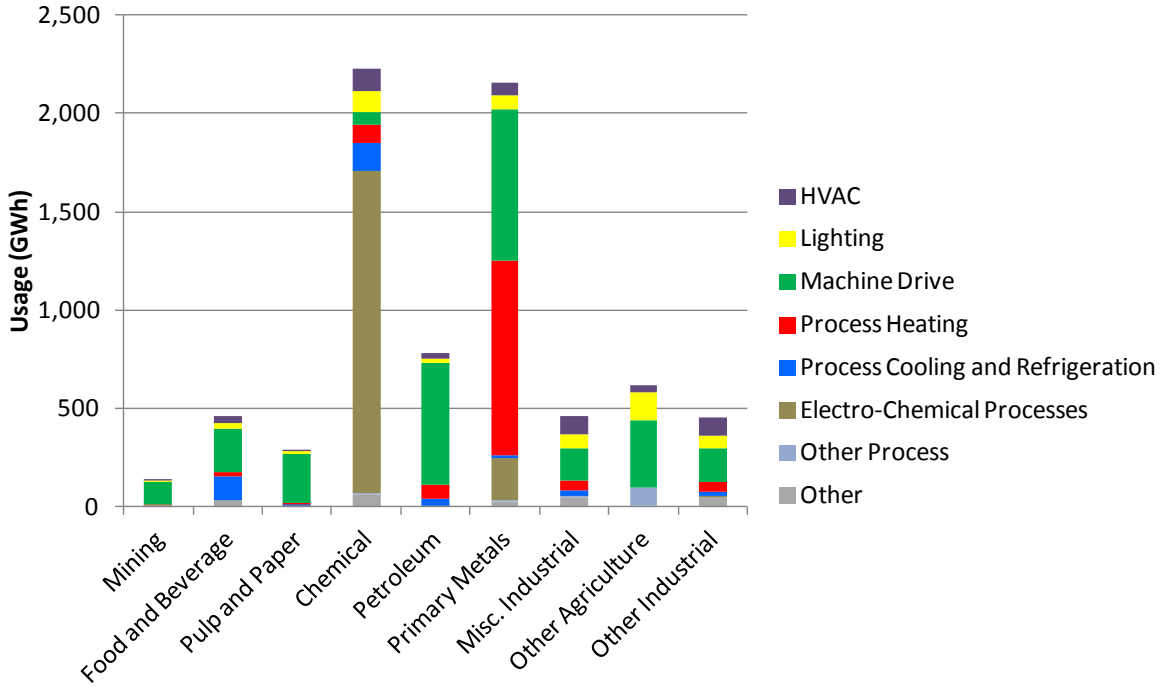


Figure 3-16 show how the major industrial segments used electricity in 2010/11. Machine drives (pumps, fans, blowers, compressed air, etc.) is prevalent among all segments, although electro-chemical process is more dominant in the chemical segment and process heating is more dominant in primary metals.

Figure 3-16 Industrial Electricity Use by End Use and Segment, 2010/11



Natural Gas Use

Total industrial natural gas use in 2010/11 was 509 MMm3. Table 3-11 presents the employees, intensity estimates, and annual gas use for each industrial segment. The three largest segments are chemicals, food and beverage, and miscellaneous industrial.

Table 3-11 Industrial Sector Natural Gas Market Characterization Results, 2010/11

Segment	Employees	Intensity (m3/emp)	Sales (MMm3)
Mining	247	3,692	0.9
Food and Beverage	7,303	23,629	172.6
Pulp and Paper	1,760	2,515	4.4
Chemical	359	419,897	150.7
Petroleum	69	68,875	4.7
Primary Metals	3,844	9,830	37.8
Misc. Industrial	775	92,273	71.5
Other Agriculture	5,414	3,480	18.8
Other Industrial	3,962	11,952	47.4
Total	**23,734**	**21,442**	**508.9**

Table 3-12 shows the natural gas market profile for the industrial sector as a whole, representing a composite of all the building types. Boilers, furnaces, and process heating are the three largest energy consuming technologies in the industrial sector.

Table 3-12 Industrial Sector Composite Natural Gas Market Profile, 2010/11

Average Market Profiles			
End Use	**Technology**	**Usage (10^6 m3)**	**Intensity (m3/Employee)**
Heating	Furnace	128.5	5,416
Heating	Boiler	178.3	7,512
Heating	Other Heating	0.0	0
Process Heating	Process Heating	143.1	6,028
Process Cooling	Process Cooling	1.5	64
Other Process	Other Process	5.0	211
Misc	Misc	52.5	2,211
Total		**508.9**	**21,442**

Figure 3-17 illustrates the overall natural gas use by end use in the industrial sector as a whole. Space heating and process heating are the largest end uses, consuming 60% and 28% of industrial building natural gas use, respectively

Figure 3-17 Industrial Gas Use by End Use, 2010/11

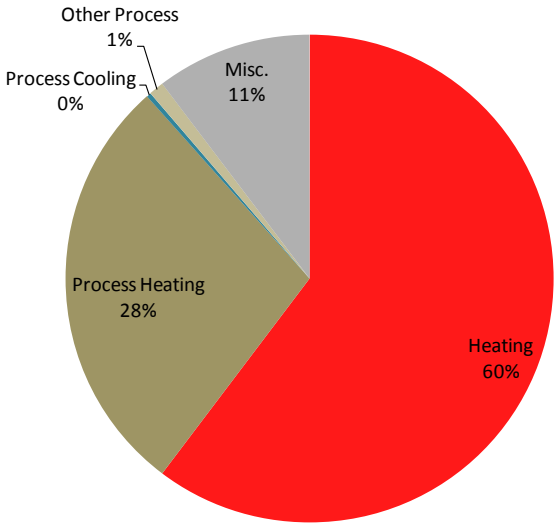
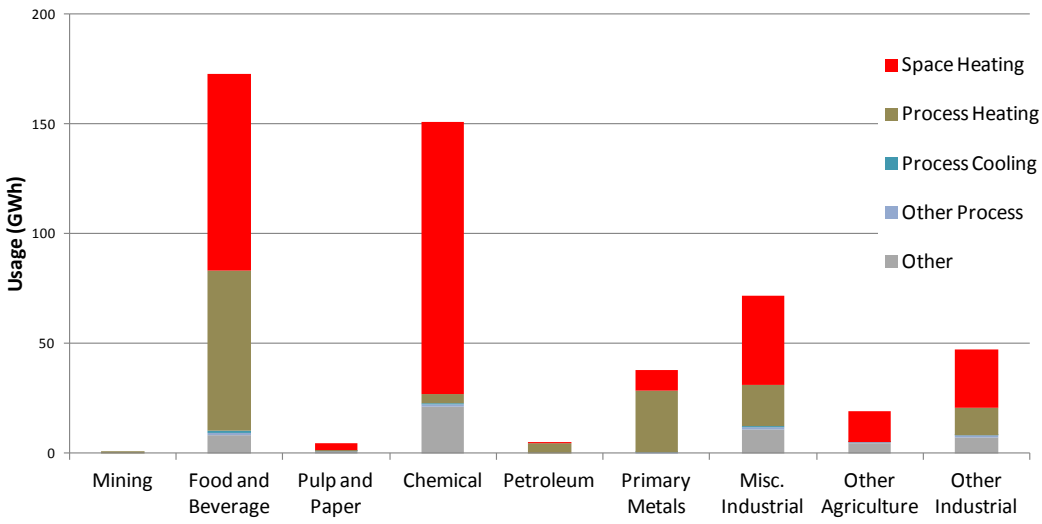


Figure 3-18 illustrates how the end-use composition of gas use varies by building type. Heating is the major end use across most segments. Process heating is a substantial use in food & beverage and primary metals.

Figure 3-18 Industrial Gas Use by End Use and Segment, 2010/11



CHAPTER | 4

BASELINE FORECAST

Prior to developing estimates of energy-efficiency potential, a baseline end-use forecast was developed to quantify how electricity and natural gas are used by end use in the base year and what the consumption is likely to be in the future in absence of new utility programs and naturally occurring efficiency. The baseline forecast serves as the metric against which energy efficiency potentials; technical, economic, and achievable, are measured. The first part of this section focuses on electricity, followed by the forecasts for natural gas.

Baseline Forecast for Electricity

In this section, the baseline end-use forecasts for the residential, commercial and industrial sectors are presented. This is followed by the combined forecast across all sectors.

Residential Sector

The baseline forecast incorporates assumptions about economic growth, electricity prices, and appliance/equipment standards and building codes that are already mandated.

Figure 4-1 presents the baseline forecast at the end-use level for the residential sector as a whole. Overall, residential use increases from 6,952 GWh in 2010/11 to 8,331 GWh in 2031/32, an increase of 20%, or an average growth of 0.9% per year.

Figure 4-1 Residential Baseline Forecast by End Use

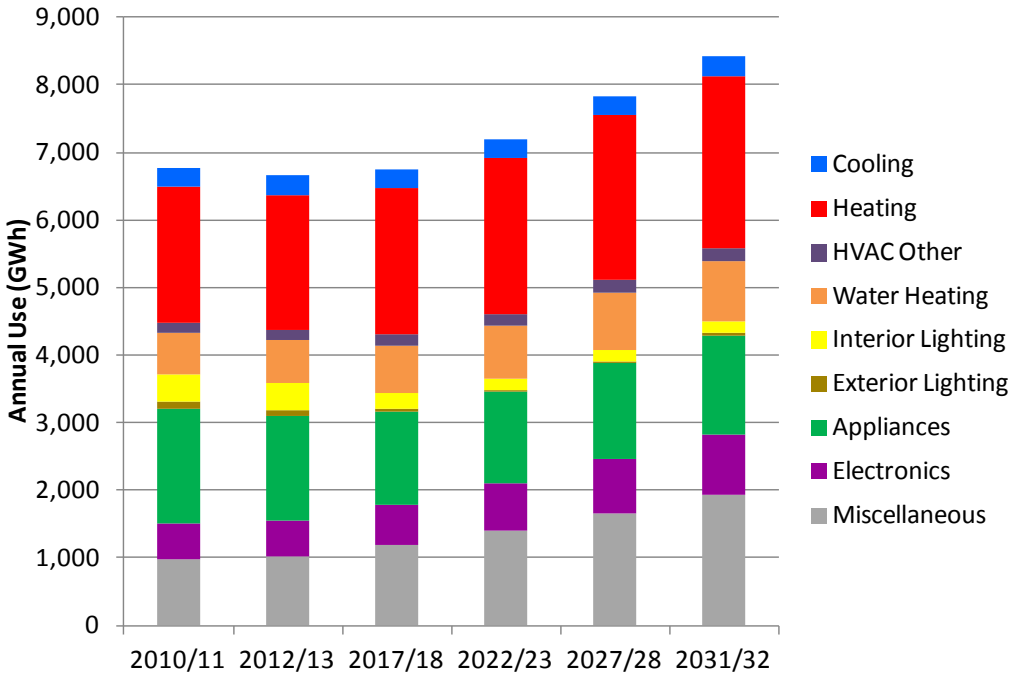


Figure 4-2 presents the forecast of use per household. Most noticeable is that lighting use decreases significantly after 2012, as the lighting standard from EISA comes into effect and as LED lamps begin to gain traction in the later years of the forecast.

Figure 4-2 Residential Baseline Electricity Use per Household by End Use

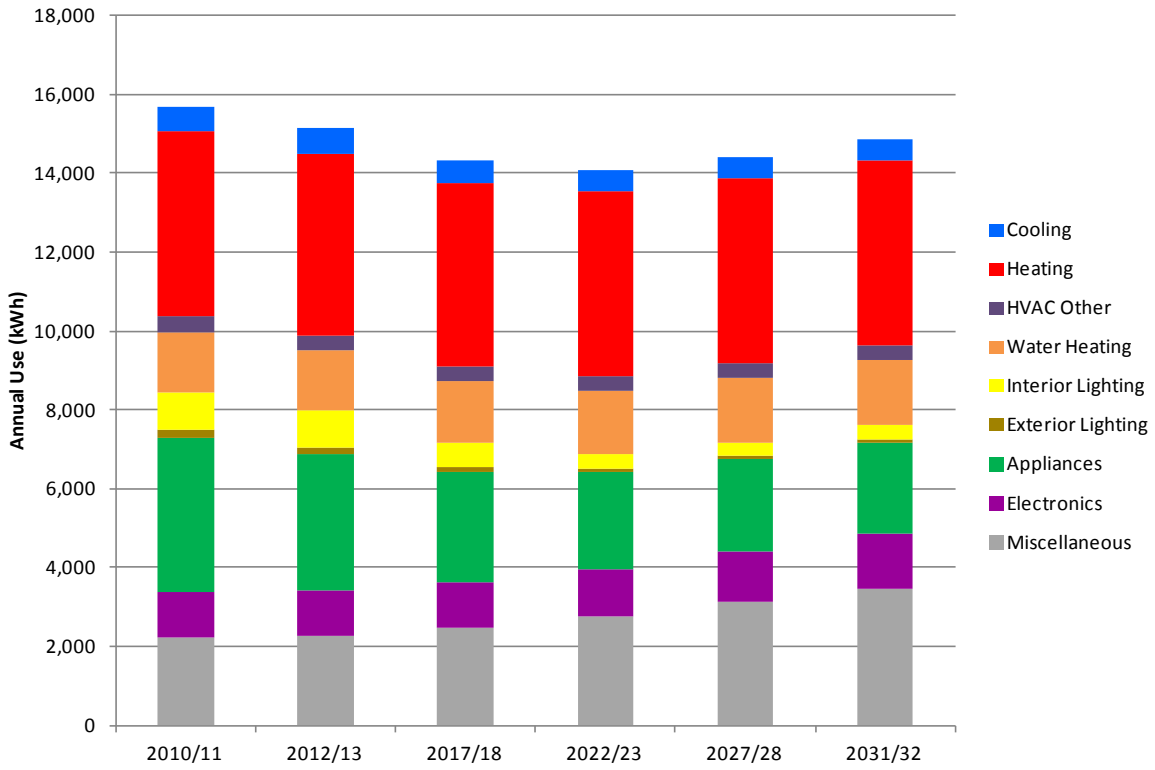


Table 4-1 shows the end-use forecast at the technology level. Specific observations include:

1. The primary reason for the reduction in the interior lighting is the federal lighting standards that have already been implemented in the U.S. and are anticipated in 2014 for Canada. The standard phases general service incandescent lamps out of the market over a three-year period. It causes a decline in interior screw-in lighting use by 58% over the forecast period.
2. Cooling increases over the forecast period due to higher saturations of central AC in new construction, but only slightly due to moderating effect of forthcoming appliance standards.
3. Appliance energy use decrease markedly, reflecting efficiency gains from standards, particularly in refrigeration appliances.
4. Growth in use in electronics is substantial and reflects an increase in the saturation of electronics and the trend toward higher-powered computers. This is tempered somewhat by the higher efficiency of televisions.
5. Growth in miscellaneous use is also substantial. This use includes various plug loads not elsewhere classified (e.g., hair dryers, power tools, coffee makers, etc.). This end use has grown consistently in the past and we incorporate future growth assumptions that are consistent with the Annual Energy Outlook.

Table 4-1 Residential Baseline Electricity Forecast by End Use and Technology (GWh)

End Use	Technology	2010/ 11	2012/ 13	2017/ 18	2022/ 23	2027/ 28	2031/ 32	% Change	Avg. Growth Rate
Cooling	Central AC	244	261	242	240	245	252	3.5%	0.2%
	Evaporative AC	0	0	0	0	0	0	N/A	N/A
	Room AC	32	36	34	33	33	33	3.5%	0.2%
	Geothermal Heat Pump	1	2	2	2	3	3	98.7%	3.3%
Heating	Geothermal Heat Pump	67	65	64	64	63	63	-6.1%	-0.3%
	Furnace	1,225	1,229	1,334	1,435	1,524	1,598	30.5%	1.3%
	Boiler	65	66	75	83	91	98	49.7%	1.9%
	Electric Resistance	648	644	677	709	737	760	17.3%	0.8%
	Supplemental Heat	75	80	95	104	111	115	53.3%	2.0%
HVAC Other	Central Exhaust	16	16	20	23	26	28	78.4%	2.8%
	Electronic Air Cleaner	47	45	48	50	52	53	14.0%	0.6%
	Humidifier	42	41	43	46	47	49	17.6%	0.8%
	Dehumidifier	66	65	67	70	73	75	14.2%	0.6%
Water Heating	Water Heater	670	687	754	821	883	935	39.6%	1.6%
	Water Heater - Tankless	2	2	2	3	3	3	83.4%	2.9%
Interior Lighting	Screw-in	394	389	257	157	159	164	-58.2%	-4.2%
	Linear Fluorescent	30	30	32	34	35	36	20.9%	0.9%
Ext. Light	Screw-in	91	86	61	38	38	39	-57.2%	-4.0%
Appliances	Clothes Washer	150	130	91	63	53	52	-65.7%	-5.1%
	Clothes Dryer	308	288	263	252	255	264	-14.4%	-0.7%
	Dishwasher	89	76	58	54	55	57	-35.7%	-2.1%
	Refrigerator	355	304	237	206	199	204	-42.6%	-2.6%
	Freezer	234	201	158	144	144	150	-35.8%	-2.1%
	Second Refrigerator	235	207	171	155	149	151	-35.5%	-2.1%
	Second Freezer	65	60	52	48	46	47	-28.1%	-1.6%
	Stove	258	263	278	293	307	318	23.2%	1.0%
	Microwave	39	40	43	46	49	51	29.4%	1.2%
Electronics	Personal Computers	103	110	128	149	172	193	86.7%	3.0%
	Monitor	19	20	23	26	31	34	79.2%	2.8%
	Laptops	16	17	21	25	29	32	98.4%	3.3%
	TVs	165	160	157	159	177	197	19.6%	0.9%
	Printer/Fax/Copier	15	17	20	24	27	31	99.5%	3.3%
	Set-top Boxes/DVR	193	190	201	229	264	296	53.2%	2.0%
Misc.	Pool Pump	39	40	43	47	50	53	35.9%	1.5%
	Pool Heater	31	32	36	39	42	45	45.1%	1.8%
	Hot Tub / Spa	87	91	103	115	126	136	55.2%	2.1%
	Well Pump	30	31	35	38	41	44	44.7%	1.8%
	Furnace Fan	408	406	430	454	476	494	20.9%	0.9%
	Sewage Pump	2	2	2	2	2	3	49.9%	1.9%
	Sump Pump	3	3	4	4	5	5	63.9%	2.4%
	Pressure Pump	35	36	39	42	44	47	32.7%	1.3%
	Sauna	18	19	20	22	23	24	31.2%	1.3%
	Car Block Heaters	43	44	47	50	53	55	28.8%	1.2%
	Car Warmers	7	7	7	8	8	8	20.7%	0.9%
	Electric Vehicles	0	1	5	13	39	74	144227 %	34.6%
	Miscellaneous	289	322	432	578	767	962	233.4%	5.7%
Total		**6,952**	**6,859**	**6,912**	**7,199**	**7,755**	**8,331**	**19.8%**	**0.9%**

Commercial Sector

Electricity use in the commercial sector grows modestly at 17% overall during the forecast horizon, an average of 0.8% per year. Usage starts at 5,685 GWh in 2010/11, decreases until 2015/16 and then increases to 6,672 GWh in 2031/32. Figure 4-3 and Table 4-2 present the baseline forecast at the end-use level for the commercial sector as a whole. Most end uses show modest growth over the forecast period. The exceptions are interior lighting, which declines due to the lighting standards, and refrigeration, which is affected by the standards for refrigeration.

Figure 4-3 Commercial Baseline Electricity Forecast by End Use

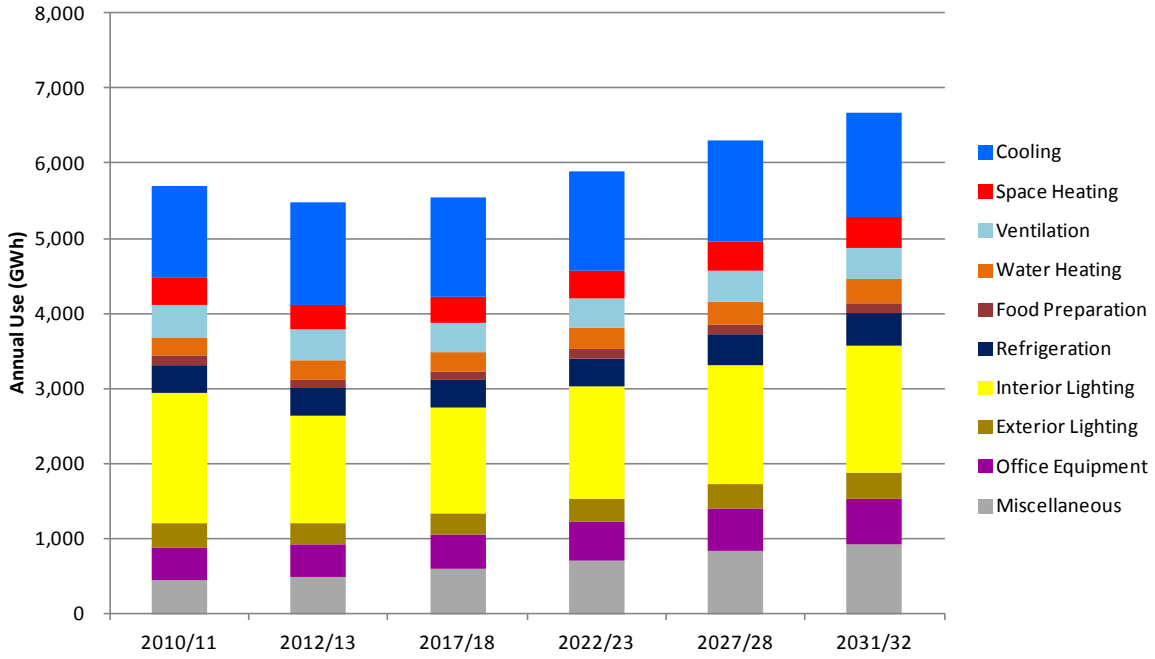


Table 4-2 Commercial Electricity Consumption by End Use (GWh)

End Use	2010/ 11	2012/ 13	2017/ 18	2022/ 23	2027/ 28	2031/ 32	% Change	Avg. Growth Rate
Cooling	1,212	1,361	1,326	1,323	1,347	1,394	15%	0.7%
Heating	362	338	347	364	386	404	12%	0.5%
Ventilation	429	412	384	394	411	425	-1%	0.0%
Water Heating	252	253	266	283	301	315	25%	1.1%
Food Preparation	111	110	111	118	127	135	21%	0.9%
Refrigeration	375	374	368	379	405	437	17%	0.7%
Interior Lighting	1,734	1,425	1,403	1,503	1,597	1,679	-3%	-0.2%
Exterior Lighting	337	286	284	305	326	344	2%	0.1%
Office Equipment	416	423	457	512	566	610	47%	1.8%
Miscellaneous	457	493	595	707	828	929	104%	3.4%
Total	**5,685**	**5,475**	**5,541**	**5,887**	**6,294**	**6,672**	**17%**	**0.8%**

Table 4-3 presents the commercial sector forecast by technology. Interior screw-in lighting decreases significantly over the forecast period as a result of the lighting standard.

Table 4-3 Commercial Baseline Electricity Forecast by End Use and Technology (GWh)

End Use	Technology	2010/ 11	2012/ 13	2017/ 18	2022/ 23	2027/ 28	2031/ 32	% Change
Cooling	Air-Cooled Chiller	85	96	95	94	94	96	12.7%
	Water-Cooled Chiller	265	299	297	297	293	298	12.5%
	Roof top AC	573	636	608	598	613	638	11.4%
	Roof top Heat Pump	98	110	106	109	115	120	22.8%
	Other Cooling	191	221	220	225	232	241	26.4%
Space Heating	Roof top Heat Pump	121	110	105	109	116	123	1.0%
	Electric Heating	241	228	241	256	270	281	16.9%
Ventilation	Ventilation	429	412	384	394	411	425	-1.0%
Water Heating	Water Heating	252	253	266	283	301	315	24.8%
	Dishwasher	51	50	47	49	53	56	8.5%
Food Preparation	Oven	22	22	24	26	29	30	40.5%
	Fryer	29	29	32	35	38	41	42.0%
	Hot Food Container	10	9	7	7	8	8	-13.9%
Refrigeration	Walk-in Refrigerator	135	128	110	104	109	120	-11.7%
	Reach-in Refrigerator	9	8	8	8	8	9	6.5%
	Glass Door Display	182	186	191	199	209	221	21.4%
	Open Display Case	27	29	31	35	38	42	51.9%
	Icemaker	19	20	23	26	30	34	72.4%
	Vending Machine	3	3	5	7	10	13	382.0%
Interior Lighting	Screw-in	725	501	451	467	499	531	-26.8%
	Linear Fluorescent	859	836	879	960	1,018	1,064	23.9%
	High-Bay Fixtures	150	88	72	76	80	83	-44.3%
Exterior Lighting	Screw-in	42	40	38	39	42	44	5.5%
	Linear Fluorescent	19	20	24	29	34	38	96.8%
	HID	275	226	222	236	250	262	-5.0%
Office Equipment	Monitor	45	45	48	53	57	61	35.2%
	Desktop Computer	242	247	260	286	310	329	35.8%
	Laptop	35	36	38	42	45	48	35.9%
	Server	50	53	66	83	101	117	134.6%
	Printer/Copier/Fax	32	31	33	36	39	41	29.3%
	POS Terminal	12	11	11	12	13	14	21.0%
Miscellaneous	Pool Pump	1	1	1	1	1	1	28.5%
	Pool Heater	0	0	0	0	0	0	40.2%
	Miscellaneous	227	255	333	422	518	601	164.5%
	Non-HVAC Motors	228	237	261	285	308	327	43.2%
Total		**5,685**	**5,475**	**5,541**	**5,887**	**6,294**	**6,672**	**17.4%**

Industrial Sector

Figure 4-4 and Table 4-4 present the baseline forecast at the end-use level for the industrial sector as a whole. Overall, industrial annual energy use increases from 7,576 GWh in 2010/11 to 9,687 GWh in 2031/32, a 28% increase, or 1.2% average growth per year.

Figure 4-4 Industrial Baseline Electricity Forecast by End Use

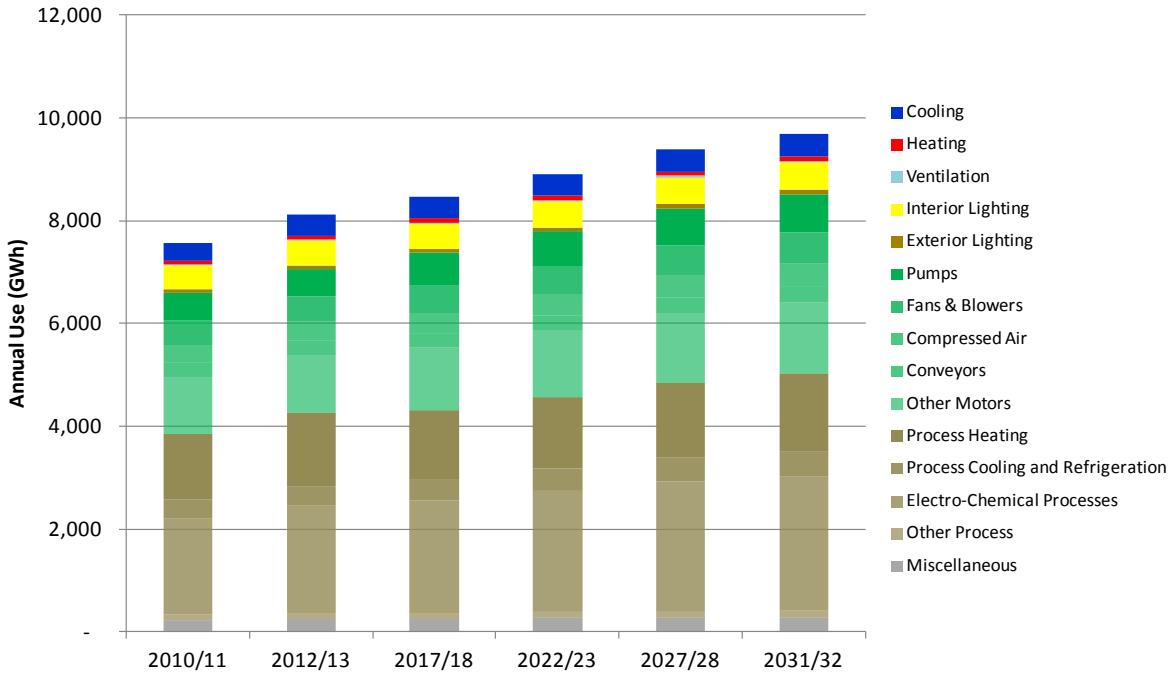


Table 4-4 Industrial Electricity Consumption by End Use (GWh)

End Use	2010/ 11	2012/ 13	2017/ 18	2022/ 23	2027/ 28	2031/ 32	% Change	Avg. Growth Rate
Cooling	349	413	417	426	437	443	27%	1.1%
Heating	78	75	77	80	83	84	9%	0.4%
Ventilation	30	31	31	32	32	33	8%	0.4%
Interior Lighting	448	465	477	494	511	522	16%	0.7%
Exterior Lighting	84	86	87	89	91	92	10%	0.5%
Pumps	524	525	638	677	720	747	43%	1.7%
Fans & Blowers	481	493	527	549	573	587	22%	0.9%
Compressed Air	333	348	389	412	437	453	36%	1.5%
Conveyors	296	308	285	293	301	306	3%	0.2%
Other Motors	1,089	1,116	1,227	1,288	1,355	1,397	28%	1.2%
Process Heating	1,288	1,421	1,322	1,393	1,468	1,513	18%	0.8%
Process Cooling and Refrig.	361	384	419	440	462	476	32%	1.3%
Electro-chemical processes	1,861	2,089	2,192	2,350	2,519	2,623	41%	1.6%
Other Process	116	118	121	124	127	129	11%	0.5%
Miscellaneous	238	250	256	265	275	281	18%	0.8%
Total	**7,576**	**8,122**	**8,462**	**8,910**	**9,392**	**9,687**	**28%**	**1.2%**

Electric Baseline Forecast Summary

Table 4-5 and Figure 4-5 provide a summary of the baseline forecast by sector and for Manitoba Hydro as a whole.

Table 4-5 Baseline Forecast Summary (GWh)

Sector	2010/11	2012/13	2017/18	2022/23	2027/28	2031/32	% Change	Avg. Growth Rate
Residential	6,952	6,859	6,912	7,199	7,755	8,331	19.8%	0.9%
Commercial	5,685	5,475	5,541	5,887	6,294	6,672	17.4%	0.8%
Industrial	7,576	8,122	8,462	8,910	9,392	9,687	27.9%	1.2%
Total	**20,213**	**20,455**	**20,915**	**21,997**	**23,441**	**24,690**	**22.1%**	**1.0%**

Figure 4-5 Baseline Forecast Summary (GWh)

Baseline Forecast for Natural Gas

In this section, the baseline natural gas forecasts for the residential, commercial and industrial sectors are presented. This is followed by the combined forecast across all sectors.

Residential Sector

The baseline forecast incorporates assumptions about economic growth, natural gas prices, and appliance/equipment standards and building codes that are already mandated.

Figure 4-6 presents the baseline forecast at the end-use level for the residential sector as a whole. Overall, residential use increases from 590 MMm3 in 2010/11 to 551 MMm3 in 2031/32, an decrease of 7%, or an average growth of -0.3% per year.

Figure 4-6 Residential Baseline Forecast by End Use

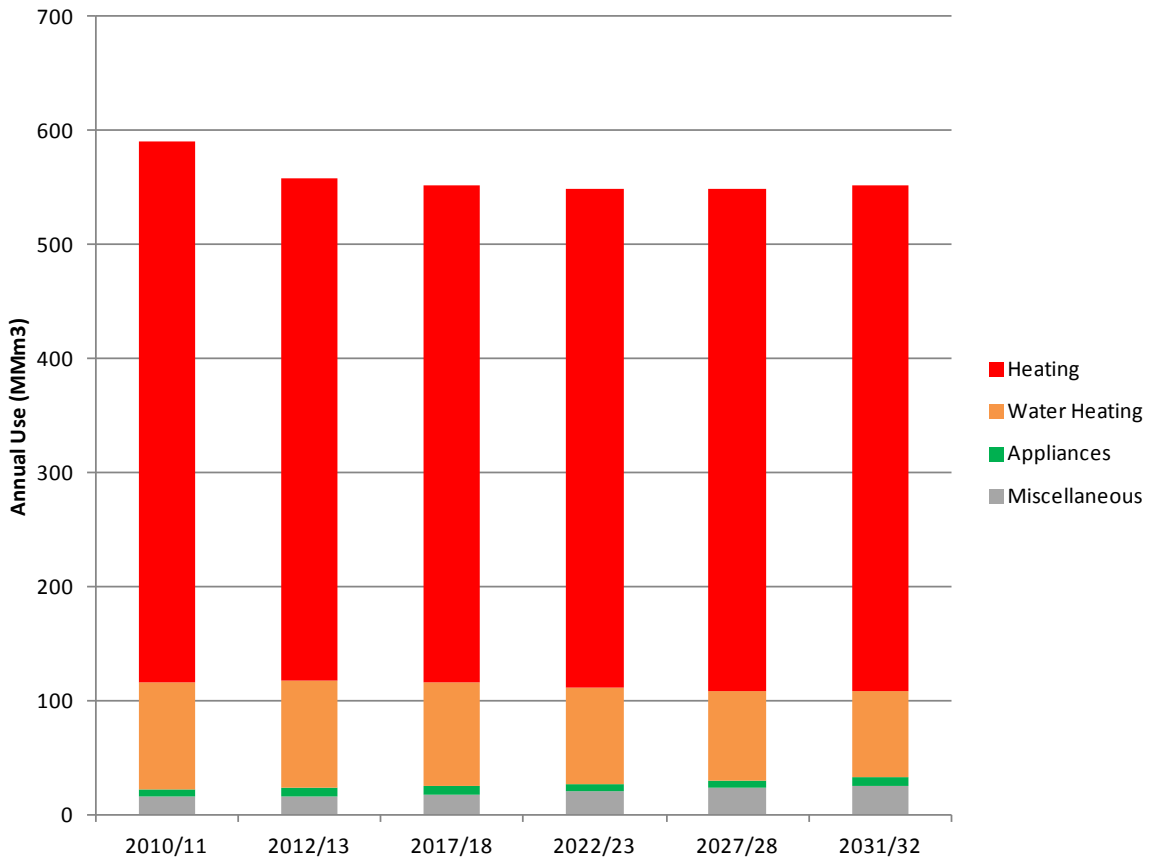


Figure 4-7 presents the forecast of use per household. Most noticeable is that lighting use decreases significantly after 2012, as the lighting standard from EISA comes into effect and as LED lamps begin to gain traction in the later years of the forecast.

Figure 4-7 Residential Baseline Natural Gas Use per Household by End Use

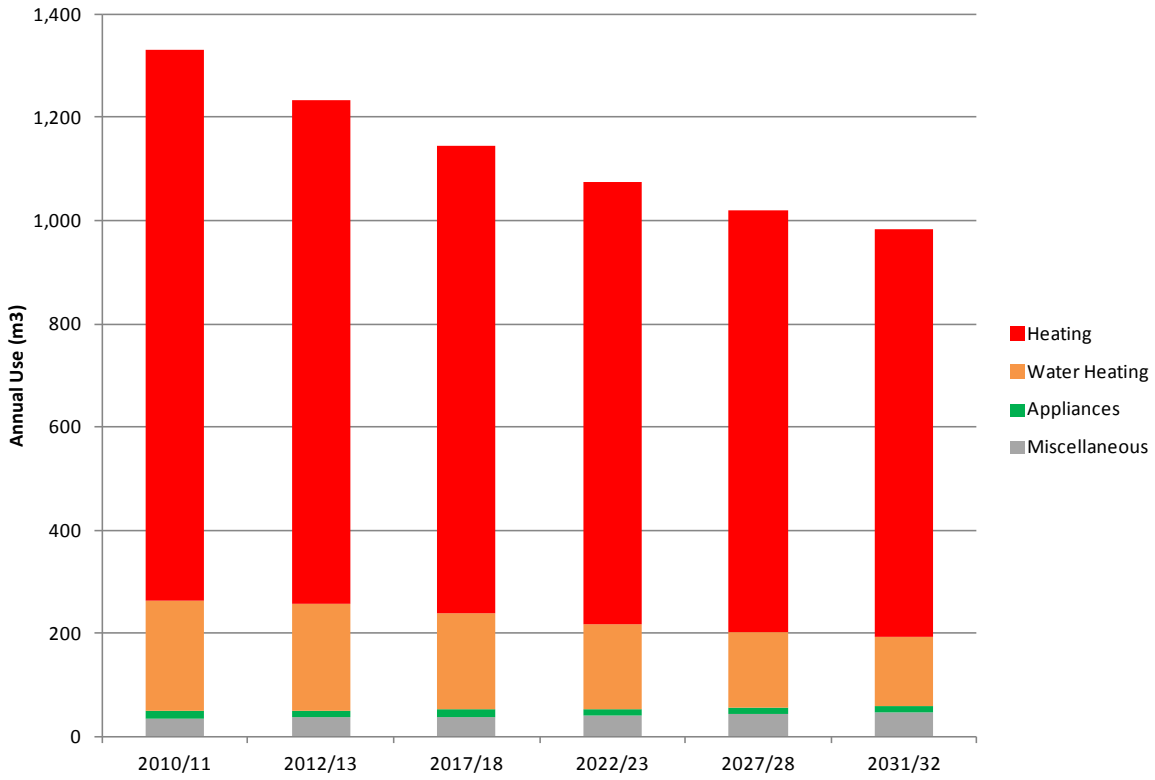


Table 4-6 shows the end-use forecast at the technology level. Specific observations include:

1. The primary reason for the reduction in the baseline forecast beginning in 2012 is the federal furnace standards. It causes a decline in furnace use by 7% over the forecast period.
2. Water heating use also decreases by 20% due to standards for water heating technology.

Table 4-6 Residential Baseline Natural Gas Forecast by End Use and Technology (MMm3)

End Use	Technology	2010/11	2012/13	2017/18	2022/23	2027/28	2031/32	% Change	Avg. Growth Rate
Heating	Furnace	430	400	395	396	399	402	-6.5%	-0.3%
	Boiler	34	32	31	31	31	31	-11.4%	-0.6%
	Supplemental Heat	10	9	10	10	11	11	12.9%	0.6%
Water Heating	Water Heater	94	94	91	85	79	75	-19.6%	-1.0%
Appliances	Stove	4	4	5	5	5	6	40.5%	1.6%
	Clothes Dryer	3	3	2	2	2	2	-41.4%	-2.5%
Miscellaneous	Pool Heater	12	12	14	16	18	20	74.9%	2.7%
	Gas Barbeque	1	1	1	2	2	2	97.4%	3.2%
	Miscellaneous	3	3	3	3	3	3	-2.5%	-0.1%
Total		**590**	**559**	**552**	**549**	**549**	**551**	**-6.5%**	**-0.3%**

Commercial Sector

Natural gas use in the commercial sector grows modestly at 8% overall during the forecast horizon, an average of 0.4% per year. Usage starts at 486 MMm3 in 2010/11, decreases until 2014 and then increases to 525 MMm3 in 2031/32. Figure 4-8 and Table 4-7 present the baseline forecast at the end-use level for the commercial sector as a whole. Most end uses show modest growth over the forecast period.

Figure 4-8 Commercial Baseline Natural Gas Forecast by End Use

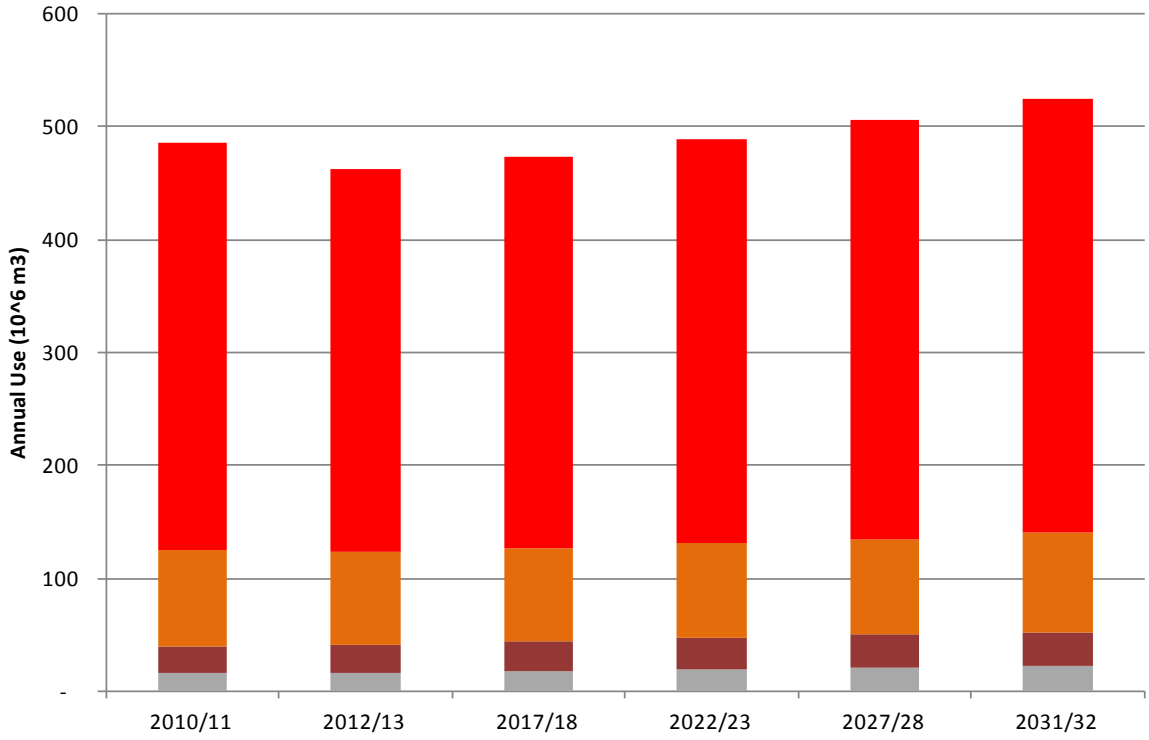


Table 4-7 Commercial Natural Gas Consumption by End Use (MMm3)

End Use	2010/11	2012/13	2017/18	2022/23	2027/28	2031/32	% Change	Avg. Growth Rate
Space Heating	361	339	346	357	370	384	6%	0.3%
Water Heating	85	82	83	85	85	88	4%	0.2%
Food Preparation	24	25	26	27	29	31	26%	1.1%
Miscellaneous	16	16	18	19	21	22	38%	1.5%
Total	**486**	**462**	**473**	**489**	**505**	**525**	**8%**	**0.4%**

Table 4-3 presents the commercial sector forecast by technology.

Table 4-8 Commercial Baseline Natural Gas Forecast by End Use and Technology (MMm3)

End Use	Technology	2010/11	2012/13	2017/18	2022/23	2027/28	2031/32	% Change	Avg. Growth Rate
Space Heating	Furnace	255	241	249	256	264	274	7.2%	0.3%
	Boiler	106	98	97	101	106	110	4.1%	0.2%
	Other Heating	-	-	-	-	-	-	NA	NA
Water Heating	Water Heating	85	82	83	85	85	88	4.2%	0.2%
Food Preparation	Oven	3	3	4	4	4	4	27.9%	1.2%
	Fryer	4	4	5	5	5	5	27.5%	1.2%
	Broiler	4	4	5	5	5	6	30.2%	1.3%
	Griddle	3	3	3	4	4	4	29.3%	1.2%
	Range	4	4	4	4	5	5	30.1%	1.3%
	Steamer	5	5	5	6	6	6	17.0%	0.7%
Miscellaneous	Pool Heater	1	1	1	1	1	1	23.3%	1.0%
	Miscellaneous	15	16	17	19	20	21	38.2%	1.5%
Total		**486**	**462**	**473**	**489**	**505**	**525**	**8.0%**	**0.4%**

Industrial Sector

Figure 4-9 and Table 4-9 present the baseline forecast at the end-use level for the industrial sector as a whole. Overall, industrial annual natural gas use increases from 509 MMm3 in 2010/11 to 579 MMm3 in 2031/32, a 14% increase, or 0.6% average growth per year.

Figure 4-9 Industrial Baseline Natural Gas Forecast by End Use

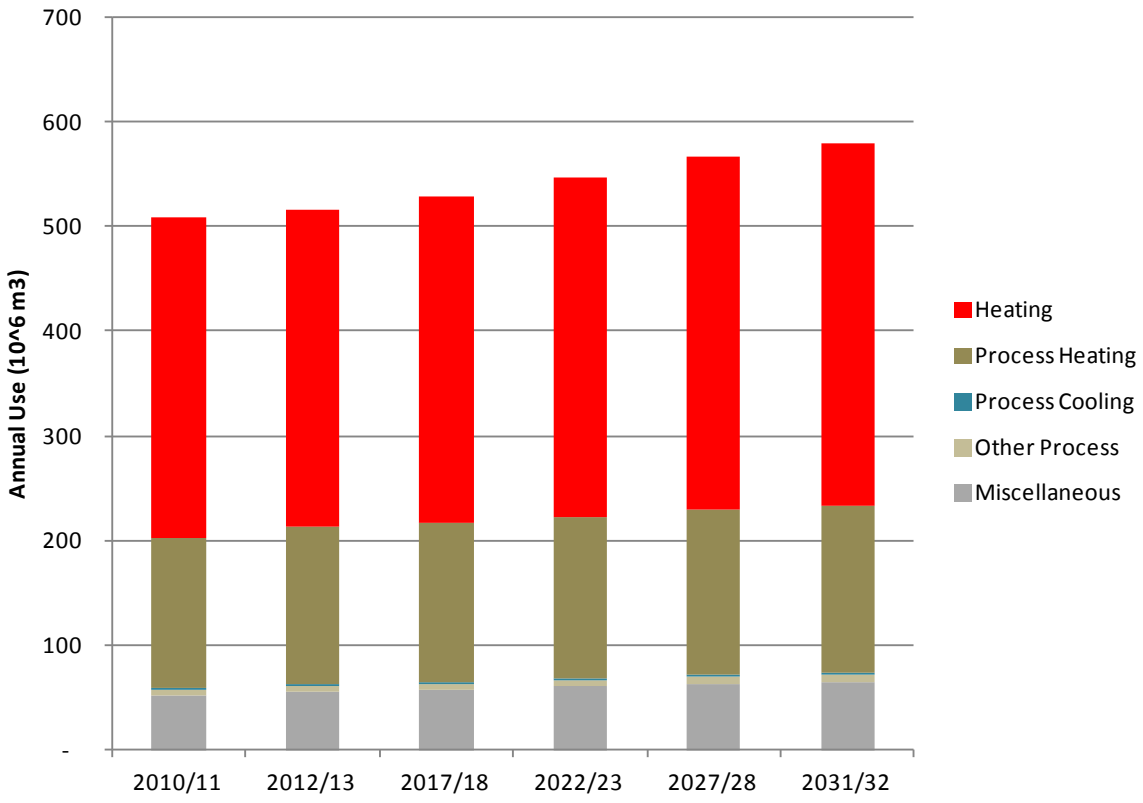


Table 4-9 Industrial Natural Gas Consumption by End Use (MMm3)

End Use	2010/11	2012/13	2017/18	2022/23	2027/28	2031/32	% Change	Avg. Growth Rate
Heating	307	304	313	325	337	345	12%	0.6%
Process Heating	143	151	151	155	158	161	12%	0.6%
Process Cooling	2	2	2	2	2	2	13%	0.6%
Other Process	5	5	5	6	6	6	19%	0.8%
Miscellaneous	52	56	58	61	63	65	24%	1.0%
Total	**509**	**517**	**529**	**547**	**567**	**579**	**14%**	**0.6%**

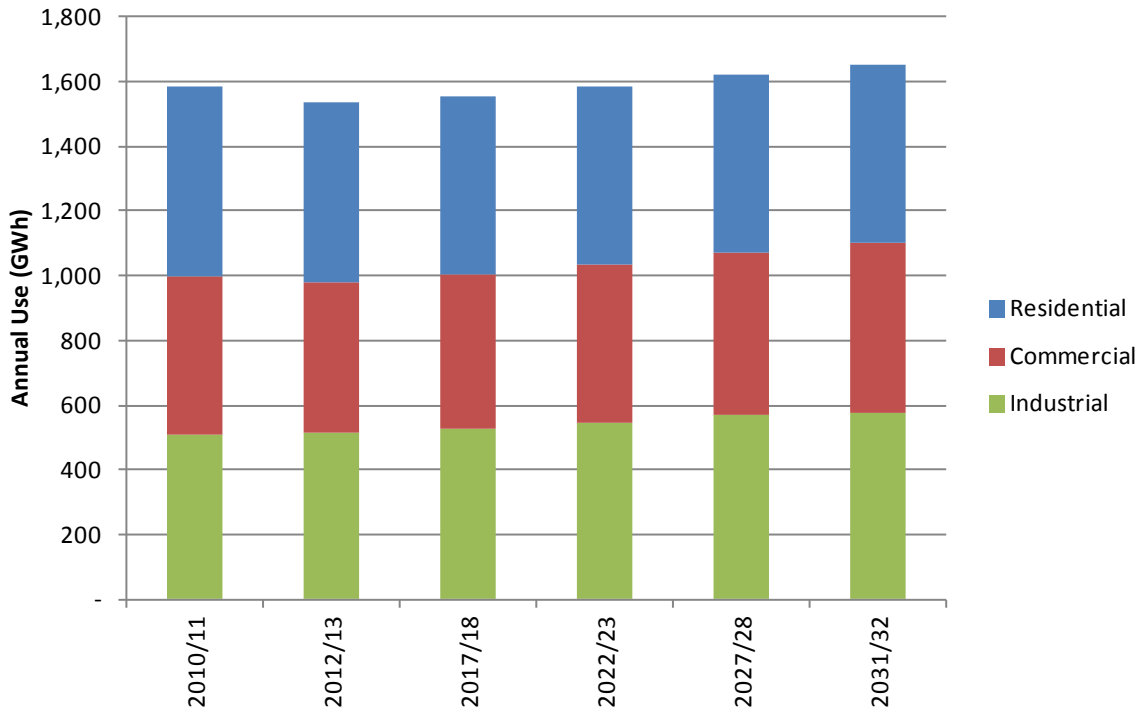
Natural Gas Baseline Forecast Summary

Table 4-10 and Figure 4-10 provide a summary of the baseline forecast by sector and for Manitoba Hydro as a whole.

Table 4-10 Baseline Forecast Summary (MMm3)

Sector	2010/11	2012/13	2017/18	2022/23	2027/28	2031/32	% Change	Avg. Growth Rate
Residential	590	559	552	549	549	551	-6.5%	-0.3%
Commercial	486	462	473	489	505	525	8.0%	0.4%
Industrial	509	517	529	547	567	579	13.7%	0.6%
Total	**1,585**	**1,537**	**1,554**	**1,586**	**1,621**	**1,655**	**4.4%**	**0.2%**

Figure 4-10 Baseline Forecast Summary (MMm3)



CHAPTER | 5

ENERGY EFFICIENCY MEASURES

List of Energy Efficiency Measures

The first step of the energy efficiency measure analysis is to identify the list of all relevant energy efficiency measures that should be considered for the potential assessment. For this study, EnerNOC prepared a preliminary list of measures for Manitoba Hydro to review. After incorporating feedback, we populated the full databases for the three sectors.

Sources for the measure assumptions were drawn from Manitoba Hydro' programs, EnerNOC's building modeling tool BEST, and EnerNOC's other measure databases from previous studies and program work.

- **Residential Measures**. The residential measures span all end uses and vary significantly in the manner in which they impact energy consumption. Table 5-1 shows the residential equipment measure options and the segments for which they were modeled. Table 5-2 shows the residential non-equipment measure options. All residential measures considered for this study are described in Appendix B.
- **Commercial Measures**. Table 5-3 and Table 5-4 present a summary of the commercial equipment and non-equipment measures, respectively. The measures shown were modeled for nearly all of the commercial building types, both new and existing, with only a few exceptions. For instance, hotel guestroom controls were only modeled for the lodging sector. All commercial measures considered for this study are described in Appendix C.
- **Industrial Measures**. Table 5-5 presents a summary of the industrial equipment and non-equipment measures, respectively. All industrial measures considered for this study are described in Appendix D.

Table 5-1 Summary of Residential Equipment Measures

End Use	Technology	Efficiency Option	Single Family (existing & new)	Multi Family (existing & new)	Mobile Home (existing & new)
Cooling	Central AC	SEER 13	X	X	X
Cooling	Central AC	SEER 14 (Energy Star)	X	X	X
Cooling	Central AC	SEER 15 (CEE Tier 2)	X	X	X
Cooling	Central AC	SEER 16 (CEE Tier 3)	X	X	X
Cooling	Central AC	Ductless Minisplit	X	X	X
Cooling	Central AC	SEER 21	X	X	X
Cooling	Room AC	EER 9.8	X	X	X
Cooling	Room AC	EER 10.8 (Energy Star)	X	X	X
Cooling	Room AC	EER 11.0	X	X	X
Cooling	Room AC	EER 12.0	X	X	X
Combined Heating/Cooling	Air-Source Heat Pump	SEER 13	X	X	X
Combined Heating/Cooling	Air-Source Heat Pump	SEER 14 (Energy Star)	X	X	X
Combined Heating/Cooling	Air-Source Heat Pump	SEER 15 (CEE Tier 2)	X	X	X
Combined Heating/Cooling	Air-Source Heat Pump	SEER 16 (CEE Tier 3)	X	X	X
Combined Heating/Cooling	Air-Source Heat Pump	Ductless Minisplit	X	X	X
Combined Heating/Cooling	Geothermal Heat Pump	EER 14.1	X	X	X
Combined Heating/Cooling	Geothermal Heat Pump	EER 16	X	X	X
Combined Heating/Cooling	Geothermal Heat Pump	EER 18	X	X	X
Combined Heating/Cooling	Geothermal Heat Pump	EER 30	X	X	X
Space Heating	Electric Resistance	Standard	X	X	X
Space Heating	Electric Furnace	Standard	X	X	X
Water Heating	Water Heater	EF 0.9	X	X	X
Water Heating	Water Heater	EF 0.95	X	X	X
Water Heating	Water Heater	EF 2.3 (HP)	X	X	X
Water Heating	Water Heater	Solar	X	X	X
Interior Lighting	Screw-in	Incandescent	X	X	X
Interior Lighting	Screw-in	Infrared Halogen	X	X	X
Interior Lighting	Screw-in	Infrared Halogen (2020)	X	X	X
Interior Lighting	Screw-in	CFL	X	X	X
Interior Lighting	Screw-in	LED	X	X	X
Interior Lighting	Linear Fluorescent	T12	X	X	X
Interior Lighting	Linear Fluorescent	T8	X	X	X
Interior Lighting	Linear Fluorescent	Super T8	X	X	X
Interior Lighting	Linear Fluorescent	T5	X	X	X
Interior Lighting	Linear Fluorescent	LED	X	X	X
Exterior Lighting	Screw-in	Incandescent	X	X	X
Exterior Lighting	Screw-in	Infrared Halogen	X	X	X
Exterior Lighting	Screw-in	Infrared Halogen (2020)	X	X	X
Exterior Lighting	Screw-in	CFL	X	X	X
Exterior Lighting	Screw-in	LED	X	X	X
Appliances	Clothes Washer	Standard (1.26)	X	X	X
Appliances	Clothes Washer	Energy Star (1.72)	X	X	X
Appliances	Clothes Washer	AHAM (MEF 1.72)	X	X	X
Appliances	Clothes Washer	Energy Star (MEF 2.0)	X	X	X
Appliances	Clothes Washer	AHAM (MEF 2.0)	X	X	X
Appliances	Clothes Washer	Compact (MEF 2.79)	X	X	X
Appliances	Clothes Dryer	Baseline	X	X	X
Appliances	Clothes Dryer	High Efficiency	X	X	X
Appliances	Clothes Dryer	Baseline (2015+)	X	X	X
Appliances	Clothes Dryer	High Efficiency (2015+)	X	X	X
Appliances	Dishwasher	Standard (EF 0.46)	X	X	X

Table 5-1 Summary of Residential Equipment Measures (continued)

End Use	Technology	Efficiency Option	Single Family (existing & new)	Multi Family (existing & new)	Mobile Home (existing & new)
Appliances	Dishwasher	Standard (EF 0.63)	X	X	X
Appliances	Dishwasher	Energy Star (EF 0.69)	X	X	X
Appliances	Dishwasher	Energy Star (EF 0.73)	X	X	X
Appliances	Dishwasher	AHAM (EF 0.73)	X	X	X
Appliances	Dishwasher	Ultra Efficient (EF 1.1)	X	X	X
Appliances	Refrigerator	Standard	X	X	X
Appliances	Refrigerator	Energy Star	X	X	X
Appliances	Refrigerator	High Efficiency	X	X	X
Appliances	Refrigerator	AHAM (2014)	X	X	X
Appliances	Refrigerator	High Efficiency (2014)	X	X	X
Appliances	Freezer	Standard	X	X	X
Appliances	Freezer	Energy Star	X	X	X
Appliances	Freezer	High Efficiency	X	X	X
Appliances	Freezer	AHAM (2014)	X	X	X
Appliances	Freezer	High Efficiency (2014)	X	X	X
Appliances	Second Refrigerator	Standard	X	X	X
Appliances	Second Refrigerator	Energy Star	X	X	X
Appliances	Second Refrigerator	High Efficiency	X	X	X
Appliances	Second Refrigerator	AHAM (2014)	X	X	X
Appliances	Second Refrigerator	High Efficiency (2014)	X	X	X
Appliances	Stove	Baseline	X	X	X
Appliances	Stove	Convection	X	X	X
Appliances	Stove	Halogen Burner	X	X	X
Appliances	Stove	Induction	X	X	X
Appliances	Microwave	Standard	X	X	X
Electronics	Personal Computer	Standard	X	X	X
Electronics	Personal Computer	Energy Star	X	X	X
Electronics	TV	Standard	X	X	X
Electronics	TV	Energy Star (3.1)	X	X	X
Electronics	TV	Energy Star (4.1)	X	X	X
Electronics	TV	Energy Star (5.1)	X	X	X
Electronics	Printer/Fax/Copier	Standard	X	X	X
Electronics	Printer/Fax/Copier	Energy Star	X	X	X
Electronics	Set-top Boxes/DVR/Audio	Standard	X	X	X
Electronics	Set-top Boxes/DVR/Audio	Energy Star (2009)	X	X	X
Electronics	Set-top Boxes/DVR/Audio	Energy Star (2011)	X	X	X
Electronics	Devices and Gadgets	Standard	X	X	X
Miscellaneous	Pool Pump	Standard	X	X	X
Miscellaneous	Pool Pump	High Efficiency	X	X	X
Miscellaneous	Pool Pump	Two-Speed	X	X	X
Miscellaneous	Pool Heater	Electric Resistance	X	X	X
Miscellaneous	Pool Heater	Heat Pump (COP = 5.0)	X	X	X
Miscellaneous	Pool Heater	Solar	X	X	X
Miscellaneous	Hot Tub / Spa	Standard	X	X	X
Miscellaneous	Hot Tub / Spa	Efficient Pumps	X	X	X
Miscellaneous	Hot Tub / Spa	Improved Controls and Pumps	X	X	X
Miscellaneous	Well Pump	Baseline (40% EF)	X	X	X
Miscellaneous	Well Pump	High Efficiency (60% EF)	X	X	X
Miscellaneous	Furnace Fan	Standard	X	X	X
Miscellaneous	Furnace Fan	ECM	X	X	X
Miscellaneous	Miscellaneous	Miscellaneous	X	X	X

Table 5-2 Summary of Residential Non-equipment Measures

Measure	Single Family Existing	Single Family New Construction	Multi Family Existing	Multi Family New Construction	Mobile Home Existing	Mobile Home New Construction
Central AC - Maintenance	X	X	X	X	X	X
Attic Fan - Installation	X	X	X	X	X	X
Attic Fan - Photovoltaic	X	X	X	X	X	X
Ceiling Fan - Installation	X	X	X	X	X	X
Whole-House Fan - Installation	X	X	X	X	X	X
Central Heat Pump - Maintenance	X	X	X	X	X	X
Dehumidifier	X	X	X	X	X	X
Thermostat - Clock/Programmable	X	X	X	X	X	X
Ducting - Repair and Sealing	X	X	X	X	X	X
Insulation - Ducting	X	X	X	X	X	X
Insulation - Infiltration Control	X	X	X	X	X	X
Insulation - Ceiling	X	X	X	X	X	X
Insulation - Foundation		X		X		X
Insulation - Wall Cavity		X		X		X
Insulation - Wall Sheathing		X		X		X
Doors - Storm and Thermal	X	X	X	X	X	X
Windows - ENERGY STAR	X	X	X	X	X	X
Windows - Install reflective film	X	X	X	X	X	X
Roofs - High Reflectivity	X	X	X	X	X	X
Interior Lighting - Occupancy Sensor	X	X	X	X	X	X
Exterior Lighting - Photovoltaic - Installation	X	X	X	X	X	X
Exterior Lighting - Photosensor Control	X	X	X	X	X	X
Exterior Lighting - Timeclock Installation	X	X	X	X	X	X
Water Heater - Faucet Aerators	X	X	X	X	X	X
Water Heater - Pipe Insulation	X	X	X	X	X	X
Water Heater - Low-Flow Showerheads	X	X	X	X	X	X
Water Heater - Tank Blanket/Insulation	X	X	X	X	X	X
Water Heater - Thermostat Setback	X	X	X	X	X	X
Water Heater - Timer	X	X	X	X	X	X
Water Heater - Hot Water Saver	X	X	X	X	X	X
Water Heater - Drainwater Heat Recovery		X		X		X
Refrigerator - Remove Second Unit	X	X	X	X	X	X
Refrigerator - Maintenance	X	X	X	X	X	X
Freezer - Remove Second Unit	X	X	X	X	X	X
Freezer - Maintenance	X	X	X	X	X	X
Home Electronics - Reduce Standby Wattage	X	X	X	X	X	X
Pool - Pump Timer	X	X	X	X	X	X
Spa - Pump Timer	X	X	X	X	X	X
Home Energy Management System	X	X	X	X	X	X
Advanced New Construction Design		X		X		X
ENERGY STAR Homes		X		X		X
Energy Efficient Manufactured Home						X

Table 5-3 Summary of Commercial Equipment Measures

End Use	Technology	Efficiency Option
Cooling	Air-Cooled Chiller	1.5 kw/ton, COP 2.3
Cooling	Air-Cooled Chiller	1.3 kw/ton, COP 2.7
Cooling	Air-Cooled Chiller	1.26 kw/ton, COP 2.8
Cooling	Air-Cooled Chiller	1.0 kw/ton, COP 3.5
Cooling	Air-Cooled Chiller	0.97 kw/ton, COP 3.6
Cooling	Water-Cooled Chiller	0.75 kw/ton, COP 4.7
Cooling	Water-Cooled Chiller	0.60 kw/ton, COP 5.9
Cooling	Water-Cooled Chiller	0.58 kw/ton, COP 6.1
Cooling	Water-Cooled Chiller	0.55 kw/Ton, COP 6.4
Cooling	Water-Cooled Chiller	0.51 kw/ton, COP 6.9
Cooling	Water-Cooled Chiller	0.50 kw/Ton, COP 7.0
Cooling	Water-Cooled Chiller	0.48 kw/ton, COP 7.3
Cooling	Roof Top AC	EER 9.2
Cooling	Roof Top AC	EER 10.1
Cooling	Roof Top AC	EER 11.2
Cooling	Roof Top AC	EER 12.0
Cooling	Roof Top AC	Ductless Minisplit
Cooling	Other Cooling	EER 9.8
Cooling	Other Cooling	EER 10.0
Cooling	Other Cooling	EER 10.2
Cooling	Other Cooling	EER 10.4
Cooling	Other Cooling	EER 10.6
Cooling	Other Cooling	EER 10.8
Cooling	Other Cooling	EER 12.0
Heating	Electric Heating	Standard
Cooling/Heating	Roof Top Heat Pump	EER 9.3
Cooling/Heating	Roof Top Heat Pump	EER 10.3
Cooling/Heating	Roof Top Heat Pump	EER 11.0
Cooling/Heating	Roof Top Heat Pump	EER 11.7
Cooling/Heating	Roof Top Heat Pump	EER 12.0
Cooling/Heating	Roof Top Heat Pump	Ductless Minisplit
Cooling/Heating	Roof Top Heat Pump	Geothermal
Ventilation	Ventilation	Constant Volume
Ventilation	Ventilation	Constant Volume with ECM
Ventilation	Ventilation	Variable Air Volume
Ventilation	Ventilation	Variable Air Volume with ECM
Water Heating	Water Heating	EF .97
Water Heating	Water Heating	EF .98
Water Heating	Water Heating	EF 2.3
Interior Lighting	Screw-in	Incandescent
Interior Lighting	Screw-in	90W Halogen PAR-38
Interior Lighting	Screw-in	70W HIR PAR-38
Interior Lighting	Screw-in	CFL
Interior Lighting	Screw-in	LED
Interior Lighting	High-Bay Fixtures	Metal Halides
Interior Lighting	High-Bay Fixtures	LED
Interior Lighting	High-Bay Fixtures	T8
Interior Lighting	High-Bay Fixtures	High Pressure Sodium
Interior Lighting	High-Bay Fixtures	T5
Interior Lighting	Linear Fluorescent	T12
Interior Lighting	Linear Fluorescent	LED
Interior Lighting	Linear Fluorescent	T8
Interior Lighting	Linear Fluorescent	Super T8
Exterior Lighting	Screw-in	Incandescent
Exterior Lighting	Screw-in	90W Halogen PAR-38
Exterior Lighting	Screw-in	70W HIR PAR-38
Exterior Lighting	Screw-in	CFL
Exterior Lighting	Screw-in	LED
Exterior Lighting	HID	Metal Halides
Exterior Lighting	HID	LED
Exterior Lighting	HID	T8
Exterior Lighting	HID	High Pressure Sodium
Exterior Lighting	HID	T5

End Use	Technology	Efficiency Option
Exterior Lighting	Linear Fluorescent	T12
Exterior Lighting	Linear Fluorescent	LED
Exterior Lighting	Linear Fluorescent	T8
Exterior Lighting	Linear Fluorescent	Super T8
Exterior Lighting	Linear Fluorescent	T5
Refrigeration	Walk-in Refrigerator	14600 kWh/yr
Refrigeration	Walk-in Refrigerator	10800 kWh/yr
Refrigeration	Walk-in Refrigerator	10000 kWh/yr
Refrigeration	Walk-in Refrigerator	9000 kWh/yr
Refrigeration	Reach-in Refrigerator	3100 kWh/yr
Refrigeration	Reach-in Refrigerator	2500 kWh/yr
Refrigeration	Reach-in Refrigerator	2400 kWh/yr
Refrigeration	Reach-in Refrigerator	1500 kWh/yr
Refrigeration	Glass Door Display	15500 kWh/yr
Refrigeration	Glass Door Display	14480 kWh/yr
Refrigeration	Glass Door Display	11700 kWh/yr
Refrigeration	Glass Door Display	8400 kWh/yr
Refrigeration	Glass Door Display	6800 kWh/yr
Refrigeration	Open Display Case	7000 kWh/yr
Refrigeration	Open Display Case	6535 kWh/yr
Refrigeration	Open Display Case	5350 kWh/yr
Refrigeration	Open Display Case	5300 kWh/yr
Refrigeration	Open Display Case	4350 kWh/yr
Refrigeration	Icemaker	7.0 kWh/100 lbs
Refrigeration	Icemaker	6.3 kWh/100 lbs
Refrigeration	Icemaker	6.0 kWh/100 lbs
Refrigeration	Icemaker	5.5 kWh/100 lbs
Refrigeration	Vending Machine	3400 kWh/year
Refrigeration	Vending Machine	2400 kWh/year
Refrigeration	Vending Machine	1700 kWh/year
Food Preparation	Oven	Standard
Food Preparation	Oven	Energy Star
Food Preparation	Fryer	Standard
Food Preparation	Fryer	Energy Star
Food Preparation	Dishwasher	Standard
Food Preparation	Dishwasher	Energy Star
Food Preparation	Hot Food Container	Standard
Food Preparation	Hot Food Container	Energy Star
Office Equipment	Desktop Computer	Standard
Office Equipment	Desktop Computer	Energy Star
Office Equipment	Laptop	Standard
Office Equipment	Laptop	Energy Star
Office Equipment	Server	Standard
Office Equipment	Server	Energy Star
Office Equipment	Monitor	Standard
Office Equipment	Monitor	Energy Star
Office Equipment	Printer/Copier/Fax	Standard
Office Equipment	Printer/Copier/Fax	Energy Star
Office Equipment	POS Terminal	Standard
Office Equipment	POS Terminal	Efficient
Miscellaneous	Non-HVAC Motors	Standard (EPAct)
Miscellaneous	Non-HVAC Motors	Standard (EPAct 2015)
Miscellaneous	Non-HVAC Motors	High Efficiency
Miscellaneous	Non-HVAC Motors	High Efficiency (2015)
Miscellaneous	Non-HVAC Motors	Premium (NEMA)
Miscellaneous	Non-HVAC Motors	Premium (NEMA 2015)
Miscellaneous	Pool Pump	Standard
Miscellaneous	Pool Pump	High Efficiency
Miscellaneous	Pool Pump	Two-Speed
Miscellaneous	Pool Heater	Standard
Miscellaneous	Pool Heater	Heat Pump
Miscellaneous	Pool Heater	Solar
Miscellaneous	Miscellaneous	Standard

Table 5-4 Summary of Commercial Non-equipment Measures

Measure	Existing	New
Chiller - VSD	X	X
Chiller - Condenser Water Temperature Reset	X	X
Chiller - Economizer	X	X
Chiller - Thermal Energy Storage	X	X
Air-Cooled Chiller - High Efficiency Fans	X	X
Water-Cooled Chiller - Cooling Tower, High-Efficiency Fans	X	X
Water-Cooled Chiller - Condenser Water Temperature Reset	X	X
Heat Pump - Maintenance	X	X
RTU - Maintenance	X	X
Ventilation - Variable Speed Control	X	X
Ventilation - CO2 Controlled	X	X
Ventilation - Exhaust Hood Sensor Control	X	X
Fans - Energy-Efficient Motors	X	X
Pumps - High-Efficiency Motors	X	X
Pumps - Variable Speed Control	X	X
Insulation - Ducting	X	X
Insulation - Ceiling	X	X
Insulation - Wall Cavity	X	X
HVAC - Duct Repair and Sealing	X	X
Roofs - Cool Roof	X	X
Windows - High Efficiency	X	X
Energy Management System	X	X
Thermostat - Clock/Programmable	X	X
Hotel - Guest Room Controls	X	X
Interior Lighting - LED Exit Lighting	X	X
Interior Lighting - Occupancy Sensors	X	X
Interior Lighting - Task Lighting	X	X
Interior Lighting - Time Clocks and Timers (lighting)	X	X
Interior Lighting - Fluorescent Delamp and Install Reflectors	X	X
Interior Fluorescent - Bi-Level Fixture w/Occupancy Sensor	X	X
Interior Fluorescent - Photocell-Controlled Dimming Ballasts	X	X
Indoor Lighting - Daylighting Controls	X	X
Lighting Retrocommissioning	X	
Water Heating - Heat Trap	X	X
Water Heating - Faucet Aerators and Low Flow Nozzles	X	X
Water Heating - Pipe Insulation	X	X
Water Heating - Tank Blanket	X	X
Water Heating - Hot Water Saver	X	X
Water Heating - High Efficiency Circulation Pump	X	X
Water Heating - Install Timer	X	X
Water Heating - Thermostat Setback	X	X
Water Heating - Solar Water Heating System	X	X
Refrigerator - Decommissioning and Recycling	X	X
Refrigerator - Anti-Sweat Heater	X	X
Refrigerator - Door Gasket Replacement	X	X
Open Display Case - Night Covers	X	X
Display Case - LED Lighting	X	X
Vending Machine - Controller	X	X
Office Electronics - Plug Load Occupancy Sensors	X	X
Office Electronics - ENERGY STAR Power Supplies	X	X
Non-HVAC Motors - Variable Speed Control	X	X
Pool Pump - Timer	X	X

Table 5-5 Summary of Industrial Equipment Measures

End Use	Technology	Efficiency Option	Food Products (existing & new)	Paper Products (existing & new)	Chemical Products (existing & new)	Primary Metals (existing & new)	Other (existing & new)
Cooling	Roof Top AC	EER 9.2	X	X	X	X	X
Cooling	Roof Top AC	EER 10.1	X	X	X	X	X
Cooling	Roof Top AC	EER 11.2	X	X	X	X	X
Cooling	Roof Top AC	EER 12.0	X	X	X	X	X
Cooling	Roof Top AC	Ductless Minisplit	X	X	X	X	X
Cooling	Other Cooling	EER 9.8	X	X	X	X	X
Cooling	Other Cooling	EER 10.0	X	X	X	X	X
Cooling	Other Cooling	EER 10.2	X	X	X	X	X
Cooling	Other Cooling	EER 10.4	X	X	X	X	X
Cooling	Other Cooling	EER 10.6	X	X	X	X	X
Cooling	Other Cooling	EER 10.8	X	X	X	X	X
Cooling	Other Cooling	EER 12.0	X	X	X	X	X
Heating	Electric Heating	Standard	X	X	X	X	X
Cooling/Heating	Roof Top Heat Pump	EER 9.3	X	X	X	X	X
Cooling/Heating	Roof Top Heat Pump	EER 10.3	X	X	X	X	X
Cooling/Heating	Roof Top Heat Pump	EER 11.0	X	X	X	X	X
Cooling/Heating	Roof Top Heat Pump	EER 11.7	X	X	X	X	X
Cooling/Heating	Roof Top Heat Pump	EER 12.0	X	X	X	X	X
Cooling/Heating	Roof Top Heat Pump	Ductless Minisplit	X	X	X	X	X
Cooling/Heating	Roof Top Heat Pump	Geothermal	X	X	X	X	X
Ventilation	Ventilation	Constant Volume	X	X	X	X	X
Ventilation	Ventilation	Constant Volume with ECM	X	X	X	X	X
Ventilation	Ventilation	Variable Air Volume	X	X	X	X	X
Ventilation	Ventilation	Variable Air Volume with ECM	X	X	X	X	X
Interior Lighting	Screw-in	Incandescent	X	X	X	X	X
Interior Lighting	Screw-in	90W Halogen PAR-38	X	X	X	X	X
Interior Lighting	Screw-in	70W HIR PAR-38	X	X	X	X	X
Interior Lighting	Screw-in	CFL	X	X	X	X	X
Interior Lighting	Screw-in	LED	X	X	X	X	X
Interior Lighting	High-Bay Fixtures	Metal Halides	X	X	X	X	X
Interior Lighting	High-Bay Fixtures	LED	X	X	X	X	X
Interior Lighting	High-Bay Fixtures	T8	X	X	X	X	X
Interior Lighting	High-Bay Fixtures	High Pressure Sodium	X	X	X	X	X
Interior Lighting	High-Bay Fixtures	T5	X	X	X	X	X
Interior Lighting	Linear Fluorescent	T12	X	X	X	X	X
Interior Lighting	Linear Fluorescent	LED	X	X	X	X	X
Interior Lighting	Linear Fluorescent	T8	X	X	X	X	X
Interior Lighting	Linear Fluorescent	Super T8	X	X	X	X	X
Exterior Lighting	Screw-in	Incandescent	X	X	X	X	X
Exterior Lighting	Screw-in	90W Halogen PAR-38	X	X	X	X	X
Exterior Lighting	Screw-in	70W HIR PAR-38	X	X	X	X	X
Exterior Lighting	Screw-in	CFL	X	X	X	X	X
Exterior Lighting	Screw-in	LED	X	X	X	X	X
Exterior Lighting	HID	Metal Halides	X	X	X	X	X
Exterior Lighting	HID	LED	X	X	X	X	X
Exterior Lighting	HID	T8	X	X	X	X	X
Exterior Lighting	HID	High Pressure Sodium	X	X	X	X	X
Exterior Lighting	HID	T5	X	X	X	X	X
Exterior Lighting	Linear Fluorescent	T12	X	X	X	X	X
Exterior Lighting	Linear Fluorescent	LED	X	X	X	X	X
Exterior Lighting	Linear Fluorescent	T8	X	X	X	X	X
Exterior Lighting	Linear Fluorescent	Super T8	X	X	X	X	X
Exterior Lighting	Linear Fluorescent	T5	X	X	X	X	X

Table 5-5 Summary of Industrial Equipment Measures (Continued)

End Use	Technology	Efficiency Option	Food Products (existing & new)	Paper Products (existing & new)	Chemical Products (existing & new)	Primary Metals (existing & new)	Other (existing & new)
Motors	1-5 HP	Standard (EPACT)	X	X	X	X	X
Motors	1-5 HP	Standard (NEMA)	X	X	X	X	X
Motors	1-5 HP	High Efficiency	X	X	X	X	X
Motors	1-5 HP	Premium	X	X	X	X	X
Motors	6-20 HP	Standard (EPACT)	X	X	X	X	X
Motors	6-20 HP	Standard (EISA)	X	X	X	X	X
Motors	6-20 HP	High Efficiency	X	X	X	X	X
Motors	6-20 HP	Premium	X	X	X	X	X
Motors	21-50 HP	Standard (EPACT)	X	X	X	X	X
Motors	21-50 HP	Standard (EISA)	X	X	X	X	X
Motors	21-50 HP	High Efficiency	X	X	X	X	X
Motors	21-50 HP	Premium	X	X	X	X	X
Motors	51-100 HP	Standard (EPACT)	X	X	X	X	X
Motors	51-100 HP	Standard (EISA)	X	X	X	X	X
Motors	51-100 HP	High Efficiency	X	X	X	X	X
Motors	51-100 HP	Premium	X	X	X	X	X
Motors	101-200 HP	Standard (EPACT)	X	X	X	X	X
Motors	101-200 HP	Standard (EISA)	X	X	X	X	X
Motors	101-200 HP	High Efficiency	X	X	X	X	X
Motors	101-200 HP	Premium	X	X	X	X	X
Motors	201-500 HP	Standard (EPACT)	X	X	X	X	X
Motors	201-500 HP	Standard (EISA)	X	X	X	X	X
Motors	201-500 HP	High Efficiency	X	X	X	X	X
Motors	201-500 HP	Premium	X	X	X	X	X
Motors	501-1000 HP	Standard	X	X	X	X	X
Motors	501-1000 HP	High Efficiency	X	X	X	X	X
Motors	501-1000 HP	Premium	X	X	X	X	X
Motors	1000+ HP	Standard	X	X	X	X	X
Motors	1000+ HP	High Efficiency	X	X	X	X	X
Motors	1000+ HP	Premium	X	X	X	X	X
Process Heating	Process Heating	Standard	X	X	X	X	X
Miscellaneous	Miscellaneous	Standard	X	X	X	X	X

Table 5-6 Summary of Industrial Non-Equipment Measures

Measure	Food Products (existing & new)	Paper Products (existing & new)	Chemical Products (existing & new)	Primary Metals (existing & new)	Other (existing & new)
Central Chiller - Chiller Water Reset	X	X	X	X	X
Central Chiller - Economizer	X	X	X	X	X
Central Chiller - High Efficiency Fans	X	X	X	X	X
Central Chiller - Maintenance	X	X	X	X	X
Central Chiller - Temprature Reset	X	X	X	X	X
Central Chiller - VSD	X	X	X	X	X
RTU - Maintenance	X	X	X	X	X
Heat Pump - Maintenance	X	X	X	X	X
Ventilation - C02 Controls	X	X	X	X	X
HVAC - Duct Insulation	X	X	X	X	X
HVAC - Duct Repair and Sealing	X	X	X	X	X
Insulation - Ceiling	X	X	X	X	X
Insulation - Wall Cavity	X	X	X	X	X
Roofs - High Reflectivity	X	X	X	X	X
Clock/Programmable Thermostat	X	X	X	X	X
Energy Management System	X	X	X	X	X
Lighting Controls	X	X	X	X	X
Bi-Level Fixture w/Occupancy Sensor	X	X	X	X	X
Daylighting Controls - Photocell Controlled Dimming Ballasts	X	X	X	X	X
Delamp and Install Reflectors	X	X	X	X	X
LED Exit Lighting	X	X	X	X	X
Occupancy Sensors	X	X	X	X	X
Task Lighting	X	X	X	X	X
Time Clocks and Timers	X	X	X	X	X
Air Compressor Demand Reduction	X	X	X	X	X
Air Compressor Equipment2		X		X	
Cold Storage Retrofit	X				
Cold Storage Tuneup	X				
Efficient Centrifugal Fan		X			
Energy Project Management	X	X	X	X	X
Fan Energy Management	X	X	X	X	X
Fan Equipment Upgrade	X	X	X	X	X
Fan System Optimization	X	X	X	X	X
Food: Refrig Storage Tuneup	X				
Groc Dist Retrofit	X				
Groc Dist Tuneup	X				
Integrated Plant Energy Management	X	X	X	X	X
Motors: Rewind 20-50 HP	X	X	X	X	X
Motors: Rewind 51-100 HP	X	X	X	X	X
Motors: Rewind 101-200 HP	X	X	X	X	X
Motors: Rewind 201-500 HP	X	X	X	X	X
Motors: Rewind 501-1000 HP	X	X	X	X	X
Motors: Rewind 1000+ HP	X	X	X	X	X
Material Handling VFD2		X			
Paper: Efficient Pulp Screen		X			
Paper: Large Material Handling		X			
Paper: Material Handling		X			
Paper: Premium Control Large Material		X			
Paper: Premium Fan		X			

Table 5-6 Summary of Industrial Non-Equipment Measures (Continued)

Measure	Food Products (existing & new)	Paper Products (existing & new)	Chemical Products (existing & new)	Primary Metals (existing & new)	Other (existing & new)
Plant Energy Management	X	X	X	X	X
Pump Energy Management	X	X	X	X	X
Pump Equipment Upgrade	X	X	X	X	X
Pump System Optimization	X	X	X	X	X
Synchronous Belts	X	X	X	X	X
Transformers-New	X	X	X	X	X
Transformers-Retrofit	X	X	X	X	X
Machine Drive - Pumping System Controls	X	X	X	X	X
Machine Drive - Pumping System Maintenance	X	X	X	X	X
Machine Drive - Pumping System Optimization	X	X	X	X	X
Refrigeration System Controls	X	X	X	X	X
Refrigeration System Maintenance	X	X	X	X	X
Refrigeration System Optimization	X	X	X	X	X
Process Heating	X	X	X	X	X
Metal: New Arc Furnace				X	
Process - Compressed Air System Controls	X	X	X	X	X
Process - Compressed Air System Maintenance	X	X	X	X	X
Process - Compressed Air System Optimization and Improvements	X	X	X	X	X
Process - Fan System Controls	X	X	X	X	X
Process - Fan System Maintenance	X	X	X	X	X
Process - Fan System Optimization	X	X	X	X	X
Custom Utility Programs - Cooling	X	X	X	X	X
Custom Utility Programs - Int Lighting	X	X	X	X	X
Custom Utility Programs - Motors	X	X	X	X	X
Custom Utility Programs - Misc	X	X	X	X	X

Results of the Economic Screen

Table 5-7 summarizes the number of equipment and non-equipment measures evaluated for each segment within each sector.

Table 5-7 Number of Measures Evaluated

	Residential	Commercial	Industrial	Total Number of Measures
Equipment Measures Evaluated	102	126	85	**313**
Non-Equipment Measures Evaluated	42	52	74	**168**
Total Measures Evaluated	**144**	**178**	**159**	**481**

Appendix B gives results for the economic screening process by segment, vintage, end use and measure for the residential sector. Appendices C and D shows the equivalent information for the commercial and industrial sectors, respectively.

CHAPTER | 6

ENERGY EFFICIENCY POTENTIAL FOR ELECTRICITY

This chapter presents the results of the energy-efficiency analysis for electricity. First, the overall potential is presented, followed by results for each sector.

Overall Energy Efficiency Potential

Table 6-1 presents the baseline forecasts of energy consumption, as well as the levels of electric energy-efficiency potential across sectors. As discussed in detail in Chapter 4, the baseline forecast across all sectors increases over the 20-year study period of 2012/13 to 2031/32. The growth is highest in the residential sector, although all sectors have somewhat tempered forecasts due to appliance and equipment standards, building codes, and a sluggish economy in the near term. Key findings related to potentials are summarized below.

- **Achievable - Low potential** forms a lower point on the range of achievable potential. Across all sectors, this metric is 1,338 GWh in 2017/18 and increases to 4,520 GWh by 2031/32. This represents 6.2% of the baseline forecast in 2017/18 and 17.7% in 2031/32.
- **Achievable - High potential** forms the upper bound on the range of achievable potential. It is 1,869 GWh in 2017/18, which represents 8.7% of the baseline forecast. By 2031/32, the cumulative savings are 5,709 GWh, 22.3% of the baseline forecast.
- **Economic potential**, which reflects the savings when all cost-effective measures are taken, is 2,862 GWh in 2017/18. This represents 13.4% of the baseline energy forecast. By 2031/32, economic potential reaches 7,234 GWh, 28.3% of the baseline energy forecast.
- **Technical potential**, which reflects the adoption of all energy efficiency measures regardless of cost-effectiveness, is a theoretical upper bound on savings. In 2017/18, energy savings are 3,506 GWh, or 16.4% of the baseline energy forecast. By 2031/32, technical potential reaches 8,379 GWh, 32.8% of the baseline energy forecast.

Figure 6-1 summarizes the energy-efficiency savings for the different levels of potential relative to the baseline forecast. Table 6-1 displays the energy-efficiency forecasts.

Table 6-1 Summary of Energy Efficiency Potential

	2012/13	2017/18	2022/23	2027/28	2031/32
Baseline Forecast (GWh)	20,703	21,430	22,932	24,343	25,569
Energy Savings (Cumulative GWh)					
Achievable - Low	50	1,338	2,864	3,903	4,520
Achievable - High	94	1,869	3,766	5,033	5,709
Economic	721	2,862	5,155	6,525	7,234
Technical	904	3,506	6,061	7,570	8,379
Energy Savings (% of Baseline)					
Achievable - Low	0.24%	6.24%	12.49%	16.03%	17.68%
Achievable - High	0.45%	8.72%	16.42%	20.67%	22.33%
Economic	3.48%	13.35%	22.48%	26.80%	28.29%
Technical	4.36%	16.36%	26.43%	31.10%	32.77%

Figure 6-1 Summary of Achievable Potential Energy Savings

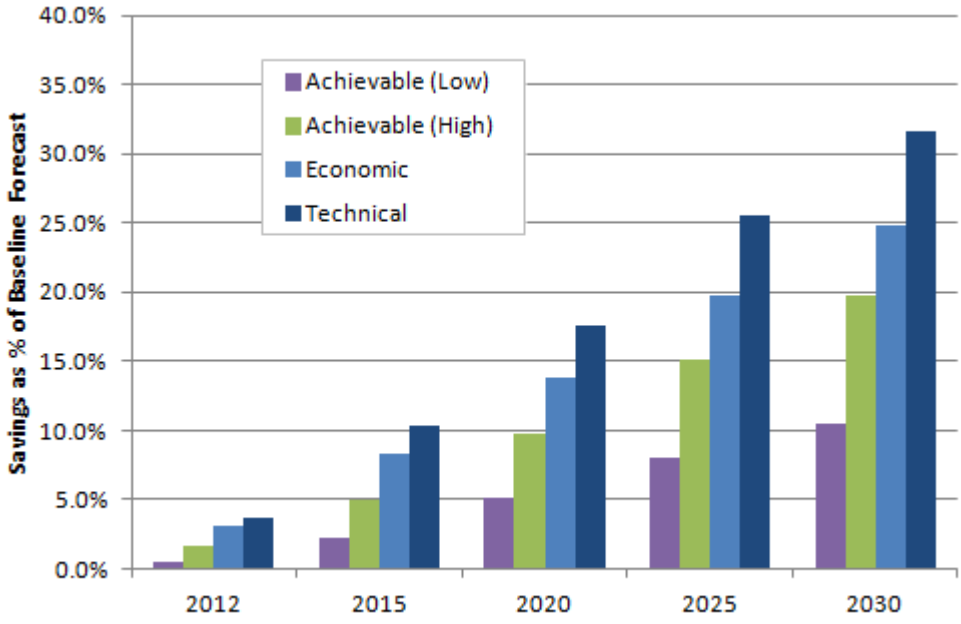
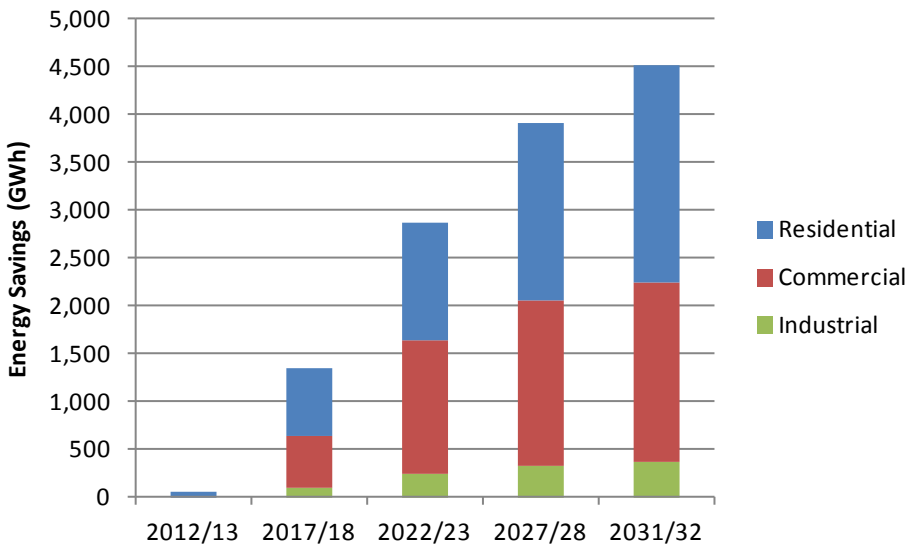


Table 6-2 and Figure 6-2 summarize the range of achievable potential by sector. The residential sector accounts for the largest portion of the savings, followed by the commercial and then the industrial sectors.

Table 6-2 Achievable Energy-efficiency Potential by Sector (GWh)

	2012/13	2017/18	2022/23	2027/28	2031/32
Achievable - Low Savings (GWh)					
Residential	50	693	1,225	1,843	2,283
Commercial	0	540	1,387	1,732	1,867
Industrial	0	104	252	328	370
Total	**50**	**1,337**	**2,864**	**3,903**	**4,520**
Achievable - High Savings (GWh)					
Residential	91	780	1,410	2,082	2,503
Commercial	2	820	1,782	2,222	2,395
Industrial	1	268	575	729	812
Total	**94**	**1,868**	**3,767**	**5,033**	**5,710**

Figure 6-2 Achievable Low Potential by Sector



Residential Sector

Table 6-3 presents estimates for the four types of potential. Figure 6-3 depicts the potential energy savings estimates graphically.

- **Achievable - Low potential** projects 693 GWh of energy savings in 2017/18, 10% of the baseline forecast. This increases to 2,283 GWh, 27% of the baseline forecast, in 2031/32.
- **Achievable - High potential** is 780 GWh in 2017/18, which represents 11% of the baseline forecast. By 2031/32, the cumulative energy savings are 2,503, 30% of the baseline forecast.
- **Economic potential,** which reflects the savings when all cost-effective measures are taken, is 1,030 GWh in 2017/18. This represents 15% of the baseline energy forecast. By 2031/32, economic potential reaches 2,745 GWh, 33% of the baseline energy forecast.
- **Technical potential,** which reflects the adoption of all energy efficiency measures regardless of cost is a theoretical upper bound on savings. In 2017/18, energy savings are 1,395 GWh, or 20% of the baseline energy forecast. By 2031/32, technical potential reaches 5,132 GWh, 38% of the baseline energy forecast.

Figure 6-4 shows the forecasts under the four types of potential along with the baseline forecast.

Table 6-3 Electricity Energy Efficiency Potential for the Residential Sector

	2012/13	2017/18	2022/23	2027/28	2031/32
Baseline Forecast (GWh)	**6,859**	**6,912**	**7,199**	**7,755**	**8,331**
Energy Savings (GWh)					
Realistic Achievable Potential	50	693	1,225	1,843	2,283
Maximum Achievable Potential	91	780	1,410	2,082	2,503
Economic Potential	203	1,030	1,706	2,354	2,745
Technical Potential	300	1,395	2,136	2,806	3,199
Energy Savings (% of Baseline)					
Realistic Achievable Potential	0.7%	10.0%	17.0%	23.8%	27.4%
Maximum Achievable Potential	1.3%	11.3%	19.6%	26.8%	30.0%
Economic Potential	3.0%	14.9%	23.7%	30.4%	32.9%
Technical Potential	4.4%	20.2%	29.7%	36.2%	38.4%

Figure 6-3 Residential Energy Efficiency Potential Savings

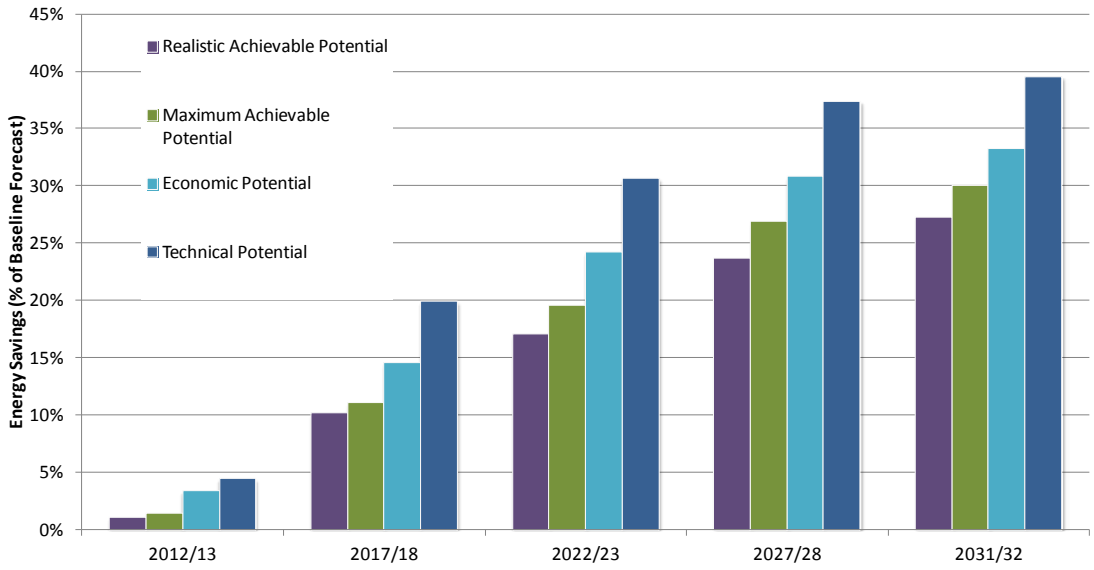
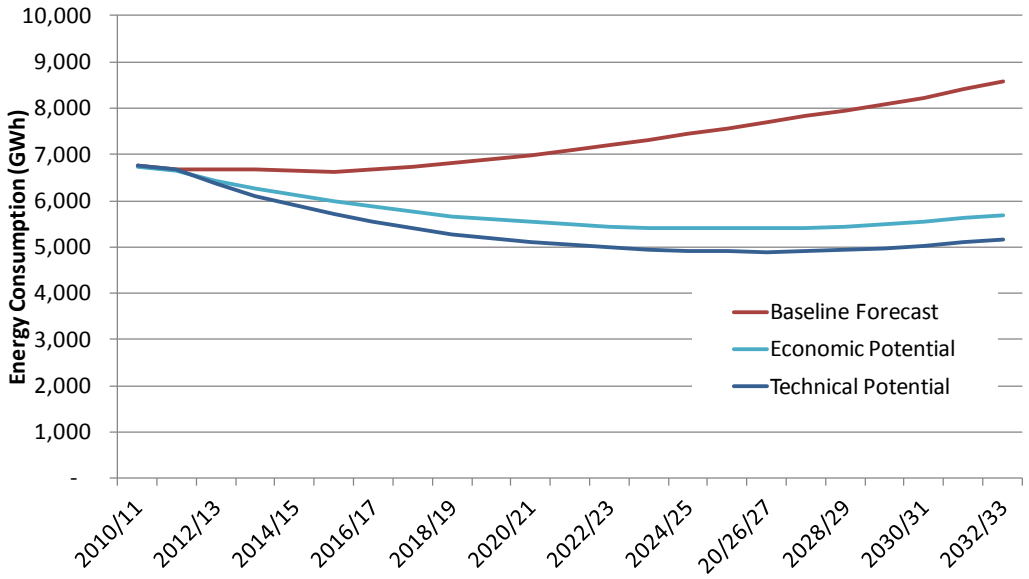


Figure 6-4 Residential Energy Efficiency Potential Forecast



Residential Potential by End Use, Technology, and Measure Type

Table 6-4 provides estimates of savings for each end use and type of potential. Focusing first on technical and economic potential, there are significant savings that are both possible and economic in numerous end uses:

- **Water Heating** offers the highest technical potential, which reflects the across the board-installation of solar water heating. However, solar water heating does not become cost-effective, using the study's assumptions of equipment cost and avoided cost, during the forecast period. The technology with the next highest efficiency is the heat pump water heater (HPWH). HPWH's are cost effective throughout the entire study, and drive high economic potentials as a result. Also included in water heating potentials are measures such as faucet aerators and low flow showerheads.
- **Cooling** offers the second-highest technical potential, which reflects across-the-board installation of SEER 21 units in homes with central air conditioning, installation of room AC units with a EER of 12 in homes with room AC, central AC maintenance, installation of various insulation measures, installation of high-efficiency windows, and AC duct repair and maintenance. However, these most efficient equipment options do not pass the economic screen at any point during the forecast, nor do the higher levels of insulation. This results in economic potential that is less than half of technical potential.
- **Combined Heating/Cooling,** or heat pumps, has similar potential to Cooling, and follows similar dynamics. The Valley has a large number of all-electric homes with air-source heat pumps, and therefore offers large amounts of energy efficiency potential in this category. The technical potential implements ductless mini splits as the highest efficiency air-source heat pump and EER 30 systems as the highest efficiency geothermal heat pump.
- **Home electronics** also offer substantial savings opportunities. Technical potential reflects the purchase of ENERGY STAR units for all technologies.
- **Interior lighting** offers the largest potential savings in the earlier half of the time horizon. The lighting standard begins its phase-in starting in 2012, which coincides with the availability in the market place of advanced incandescent lamps that meet the minimum efficacy standard. The baseline forecast assumes that people will install both advanced incandescent and CFLs in screw-in lighting applications, and that traditional incandescent will still make up one fifth of the market for specialty lighting and other applications that are

exempt from the lighting standard. For technical potential, LED lamps are the most efficient option, starting in 2012. However, LED lamps do not pass the economic screen until late in the time horizon, so CFLs dominate for most of the earlier years.

- **Appliances** also have significant technical potential savings. This reflects both the replacement of failed white-goods appliances with the highest-efficiency option and removal of second refrigerators in appliance recycling programs.

Table 6-4 Residential Savings by End Use and Potential Type (GWh)

End Use	Case	2012/13	2017/18	2022/23	2027/28	2031/32
Cooling	Achievable Low Potential	2	31	63	97	117
	Achievable High Potential	4	32	66	99	119
	Economic Potential	7	33	68	102	122
	Technical Potential	19	76	132	169	186
Heating	Achievable Low Potential	26	322	654	1,016	1,239
	Achievable High Potential	43	332	680	1,042	1,264
	Economic Potential	73	342	709	1,072	1,293
	Technical Potential	86	377	779	1,165	1,388
HVAC Other	Achievable Low Potential	0	1	4	12	19
	Achievable High Potential	0	4	12	23	30
	Economic Potential	2	13	24	34	39
	Technical Potential	2	15	25	35	39
Water Heating	Achievable Low Potential	6	137	239	342	437
	Achievable High Potential	9	152	295	433	532
	Economic Potential	13	190	375	522	618
	Technical Potential	40	292	486	639	707
Interior Lighting	Achievable Low Potential	3	35	34	78	104
	Achievable High Potential	16	60	54	104	119
	Economic Potential	64	135	84	118	124
	Technical Potential	74	180	94	95	120
Exterior Lighting	Achievable Low Potential	2	13	14	26	32
	Achievable High Potential	5	19	18	30	34
	Economic Potential	15	34	24	32	35
	Technical Potential	19	49	32	35	39
Appliances	Achievable Low Potential	10	132	143	138	140
	Achievable High Potential	12	143	167	162	164
	Economic Potential	15	156	197	190	192
	Technical Potential	29	210	274	271	276
Electronics	Achievable Low Potential	0	18	57	95	134
	Achievable High Potential	2	30	89	133	165
	Economic Potential	10	79	143	175	199
	Technical Potential	13	98	148	178	202
Miscellaneous	Achievable Low Potential	0	4	17	39	61
	Achievable High Potential	1	9	30	55	75
	Economic Potential	5	47	82	110	122
	Technical Potential	17	98	166	218	242
Total	**Achievable Low Potential**	**50**	**693**	**1,225**	**1,843**	**2,283**
	Achievable High Potential	**91**	**780**	**1,410**	**2,082**	**2,503**
	Economic Potential	**203**	**1,030**	**1,706**	**2,354**	**2,745**
	Technical Potential	**300**	**1,395**	**2,136**	**2,806**	**3,199**

As described in Chapter 2, using our LoadMAP model, we develop separate estimates of potential for equipment and non-equipment measures. Table 6-5 presents Achievable – Low results for equipment at the technology level and Table 6-6 presents non-equipment measures for which Achievable - Low potential is greater than zero. The majority of the savings come from the equipment measures, with lighting and water heating leading the way. Electronics, heat pumps, and pool pumps/heaters provide significant savings as well.

Table 6-5 Residential Achievable - Low Potential by Technology – Select years (GWh)

Equipment		2012/13	2017/18	2022/23	2027/28	2031/32
Cooling	Achievable Low Potential	0.0	0.0	0.0	0.0	0.1
	Achievable High Potential	0.0	0.0	0.0	0.1	0.1
	Economic Potential	0.0	0.1	0.1	0.2	0.2
	Technical Potential	4.6	21.9	37.0	50.4	54.8
Heating	Achievable Low Potential	0.0	0.1	0.4	1.3	1.6
	Achievable High Potential	0.1	0.5	1.3	2.7	3.1
	Economic Potential	0.2	1.7	3.0	4.6	5.0
	Technical Potential	0.2	1.7	3.1	4.7	5.2
HVAC Other	Achievable Low Potential	0.0	0.8	4.1	11.6	18.6
	Achievable High Potential	0.4	3.7	11.5	23.0	30.1
	Economic Potential	1.7	13.2	24.3	34.4	38.8
	Technical Potential	2.4	14.8	24.9	34.8	39.1
Water Heating	Achievable Low Potential	0.0	9.0	54.8	146.3	243.3
	Achievable High Potential	0.5	18.5	104.0	244.3	350.6
	Economic Potential	2.1	57.5	187.8	344.7	451.6
	Technical Potential	28.5	164.6	322.1	494.1	555.9
Interior Lighting	Achievable Low Potential	2.7	34.4	32.7	77.0	103.2
	Achievable High Potential	15.6	59.4	53.2	103.3	118.1
	Economic Potential	63.5	134.4	82.5	116.7	123.3
	Technical Potential	73.1	177.1	89.6	90.4	115.1
Exterior Lighting	Achievable Low Potential	0.6	8.1	7.4	17.6	23.7
	Achievable High Potential	3.3	13.9	12.1	23.5	26.9
	Economic Potential	13.3	31.3	18.3	26.4	27.9
	Technical Potential	15.6	40.4	18.0	18.0	23.8
Appliances	Achievable Low Potential	0.0	0.1	0.1	0.0	0.0
	Achievable High Potential	0.3	0.9	0.8	0.2	0.1
	Economic Potential	1.0	3.3	3.1	0.8	0.3
	Technical Potential	15.1	60.0	90.1	93.1	96.6
Electronics	Achievable Low Potential	0.1	3.5	19.5	50.5	85.9
	Achievable High Potential	2.0	14.7	46.2	83.8	110.5
	Economic Potential	10.3	63.5	97.8	121.3	138.6
	Technical Potential	10.3	63.5	97.8	121.3	138.6
Miscellaneous	Achievable Low Potential	0.1	3.6	16.7	38.8	61.4
	Achievable High Potential	0.8	9.2	29.8	55.3	75.2
	Economic Potential	5.4	46.6	82.1	110.1	122.0
	Technical Potential	17.2	96.9	162.5	213.7	236.9
Total	**Achievable Low Potential**	**3.4**	**59.5**	**135.7**	**343.2**	**537.7**
	Achievable High Potential	**22.9**	**120.8**	**258.9**	**536.3**	**714.7**
	Economic Potential	**97.5**	**351.4**	**499.0**	**759.2**	**907.6**
	Technical Potential	**166.9**	**640.8**	**845.1**	**1,120.5**	**1,266.1**

Note: Values shown as 0.0 are non-zero but are very small.

Table 6-6 Residential Achievable - Low Savings for Non-equipment Measures (GWh)

Measure	2012/13	2017/18	2022/23	2027/28	2031/32
Advanced New Construction Designs	0.0	4.1	24.4	72.6	117.4
Attic Fan, Installation	-	-	-	-	-
Attic Fan, Photovoltaic	-	-	-	-	-
Ceiling Fan, Installation	0.1	0.5	1.0	1.3	1.8
Central Air Conditioner - Maintenance and Tune-Up	-	-	-	-	-
Central Heat Pump - Maintenance	0.0	0.0	0.0	0.0	0.0
Doors, Storm and Thermal	0.0	0.3	1.1	2.7	3.9
Ducting, Repair and Sealing	5.5	66.2	163.2	264.1	314.5
ENERGY STAR Homes	0.0	2.5	14.8	46.7	76.7
Faucet Aerators	0.2	1.6	6.1	10.8	11.9
Freezer, Maintenance	-	-	-	-	-
Freezer, Remove Second Unit	2.2	30.5	33.7	32.7	33.2
Home Electronics - Reduce Standby Wattage	0.0	14.7	37.9	44.1	48.1
Home Energy Management System	5.0	26.3	45.9	55.2	60.1
Insulation - Infiltration Control	4.6	70.4	76.0	68.9	66.1
Insulation, Ceiling	8.3	90.6	206.5	324.6	387.5
Insulation, Ducting	0.8	7.9	16.4	23.3	26.2
Insulation, Foundation	0.0	0.3	1.4	4.7	8.0
Insulation, Wall Cavity	3.8	43.0	101.3	158.8	183.0
Insulation, Wall Sheathing	0.0	0.1	0.6	1.6	2.0
Low-Flow Showerheads	2.3	41.3	50.7	49.4	46.7
Occupancy Sensor	-	-	-	-	-
Outdoor Lighting - Photosensor Control	-	-	-	-	-
Outdoor Lighting - Photovoltaic, Installation	-	-	-	-	-
Outdoor Lighting - Timeclock Installation	-	-	-	-	-
Pipe Insulation	0.0	0.2	1.0	3.4	5.6
Pool, Pump Timer	-	-	-	-	-
Pool, Solar Heating System	-	-	-	-	-
Refrigerator, Maintenance	-	-	-	-	-
Refrigerator, Remove Second Unit	7.5	101.2	109.1	105.7	107.2
Spa, Pump Timer	-	-	-	-	-
Spa, Solar Heating System	-	-	-	-	-
Thermostat, Clock/Programmable	2.1	36.2	44.6	45.6	46.9
Water Heater, Tank Blanket/Insulation	0.7	9.0	30.4	37.6	36.1
Water Heater, Thermostat Setback	0.8	36.1	48.5	46.3	43.3
Water Heater, Timer	-	-	-	-	-
Water Heating, Drainwater Heat Recovery	0.0	0.1	0.7	4.5	8.8
Water Heating, Hot Water Saver	2.4	39.8	46.2	43.8	40.8
Whole-House Fan, Installation	-	0.0	0.0	0.1	0.2
Windows, ENERGY STAR	0.1	11.2	27.4	50.9	68.7
Measures Total	**46.3**	**634.0**	**1,089.1**	**1,499.3**	**1,744.9**
% of Total Equipment and Non-Equipment Measures	**93%**	**91%**	**89%**	**81%**	**76%**

Commercial Sector Potential

The baseline forecast for the commercial sector only grows slightly, which reflects the sluggish near-term economy and forthcoming codes and standards. Nevertheless, the opportunity for energy-efficiency savings is still significant for the commercial sector.

- **Achievable - Low potential** projects 540 GWh of energy savings in 2017/18 and 1,867 GWh in 2031/32. This corresponds to 9.0% of the baseline forecast in 2017-18 and 25% in 2031-32.
- **Achievable - High potential** is 820 GWh in 2017-18, which represents 14% of the baseline forecast. By 2031-32, the cumulative energy savings are 2,395 GWh, 32.0% of the baseline.
- **Economic potential**, which reflects the savings when all cost-effective measures are taken, is 1,443 GWh in 2017-18. This represents 24% of the baseline energy forecast. By 2031-32, economic potential reaches 3,497 GWh, 46% of the baseline energy forecast.
- **Technical potential,** which reflects the adoption of all energy efficiency measures regardless of cost, is a theoretical upper bound on savings. In 2017/18, energy savings are 1,687 GWh, or 28.0% of the baseline energy forecast. By 2031/32, technical potential reaches 3,947 GWh, 52.0% of the baseline energy forecast.

Table 6-7 and Figure 6-5 present the savings associated with each level of potential. Figure 6-6 shows the commercial sector forecasts for the various levels of potential.

Table 6-7 Energy Efficiency Potential for the Commercial Sector

	2012/13	2017/18	2022/23	2027/28	2031/32
Baseline Forecast (GWh)	**5,723**	**6,056**	**6,823**	**7,195**	**7,551**
Savings (GWh)					
Achievable - Low	0	540	1,387	1,732	1,867
Achievable - High	2	820	1,782	2,222	2,395
Economic	473	1,443	2,738	3,276	3,497
Technical	547	1,687	3,117	3,694	3,947
Savings (% of Baseline)					
Achievable - Low	0%	9%	20%	24%	25%
Achievable - High	0%	14%	26%	31%	32%
Economic	8%	24%	40%	46%	46%
Technical	10%	28%	46%	51%	52%

Figure 6-5 Commercial Energy Efficiency Potential Savings

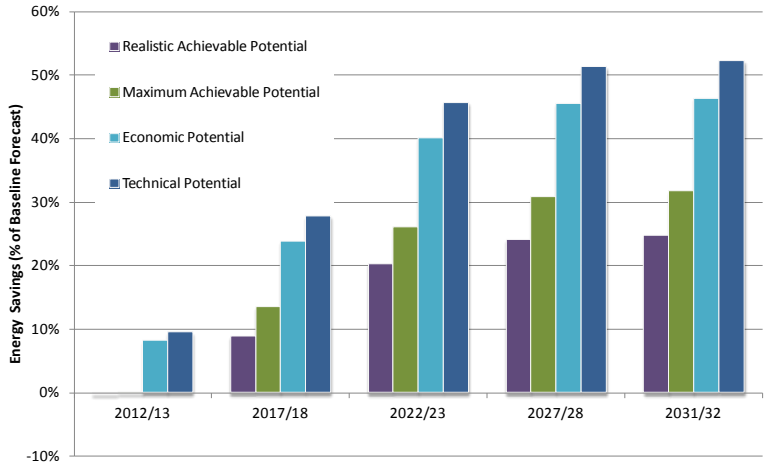
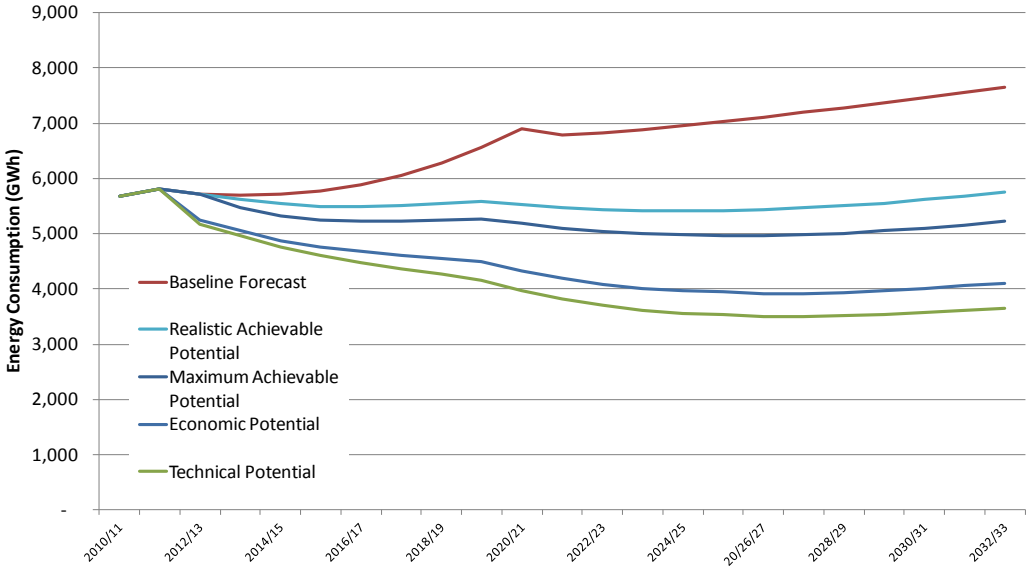


Figure 6-6 Commercial Energy Efficiency Potential Forecast



Commercial Potential by End Use, Technology, and Measure Type

Table 6-8 presents the commercial sector savings by end use and potential type. The end uses with the highest technical and economic potential are:

- Interior lighting, as a result of LED lighting that is now commercially available for screw-in applications, has the highest technical potential at 1,632 GWh in 2015. Moreover, most of the lighting equipment and measures are cost-effective resulting in economic potential of 1,561 GWh, which is 96% of technical potential. In the Achievable – Low case, roughly a third of the economic potential, 525 GWh can be captured in 2015.
- Cooling has the second highest savings for technical potential at 614 GWh in 2015. These savings result from installation of high-efficiency equipment and numerous thermal shell measures, HVAC control strategies, and retrocommissioning. Many of these measures are cost-effective, resulting in economic potential savings of 249 GWh in 2015, or 40% of technical potential savings. Achievable – Low potential is 53 GWh in 2015.
- Exterior lighting takes third place for technical potential savings at 529 GWh in 2015. The savings result from LED lighting that is commercially available. Nearly all of these measures are cost-effective, resulting in economic potential of 528 GWh in 2015. Achievable – Low potential is 169 GWh in 2015.

Ventilation, office equipment, water heating, combined heating and cooling, and refrigeration also have significant savings in terms of technical and economic potential. The savings potential from space heating, food preparation, and miscellaneous uses are relatively small.

Table 6-8 focuses on achievable potential savings. Not surprisingly, interior lighting delivers the highest achievable savings throughout the study period. In 2015, exterior lighting is second, office equipment is third, and ventilation and cooling are next highest in terms of Achievable - Low potential. In 2030, though interior lighting still provides the greatest Achievable - Low potential, cooling is the second greatest source of savings, followed by refrigeration and exterior lighting.

Table 6-8 Commercial Potential by End Use and Potential Type (GWh)

End Use	Case	2012/13	2017/18	2022/23	2027/28	2031/32
Cooling	Achievable - Low	0	6	20	37	48
	Achievable - High	0	15	42	73	93
	Economic	50	206	387	493	553
	Technical	72	280	493	625	700
Space Heating	Achievable - Low	0	1	3	4	6
	Achievable - High	0	3	6	9	11
	Economic	9	29	57	80	96
	Technical	11	35	70	99	121
Ventilation	Achievable - Low	0	14	37	55	61
	Achievable - High	0	35	81	110	119
	Economic	18	105	176	202	221
	Technical	28	134	232	275	303
Water Heating	Achievable - Low	0	12	32	58	72
	Achievable - High	0	30	69	120	143
	Economic	14	78	131	183	193
	Technical	15	80	133	185	195
Food Preparation	Achievable - Low	0	1	3	5	6
	Achievable - High	0	3	7	10	12
	Economic	1	6	11	13	14
	Technical	1	6	11	13	14
Refrigeration	Achievable - Low	0	7	19	32	43
	Achievable - High	2	19	43	68	89
	Economic	15	55	100	137	160
	Technical	16	59	106	144	168
Interior Lighting	Achievable - Low	0	144	344	600	708
	Achievable - High	0	240	512	789	878
	Economic	288	423	752	1,011	1,096
	Technical	310	521	890	1,123	1,207
Exterior Lighting	Achievable - Low	0	338	900	906	887
	Achievable - High	0	436	967	977	979
	Economic	64	473	1,033	1,049	1,046
	Technical	76	486	1,050	1,063	1,055
Office Equipment	Achievable - Low	0	17	27	32	35
	Achievable - High	0	38	53	61	67
	Economic	12	57	66	75	82
	Technical	15	70	90	109	122
Miscellaneous	Achievable - Low	0	0	1	2	3
	Achievable - High	0	1	3	4	5
	Economic	2	10	25	33	36
	Technical	3	16	43	57	62
Total	**Achievable - Low**	**0**	**540**	**1,387**	**1,732**	**1,867**
	Achievable - High	**2**	**820**	**1,782**	**2,222**	**2,395**
	Economic	**473**	**1,443**	**2,738**	**3,276**	**3,497**
	Technical	**547**	**1,687**	**3,117**	**3,694**	**3,947**

Table 6-9 and Table 6-10 present achievable potential savings for equipment measures and non-equipment measures, respectively, under the Achievable - Low case. The greatest savings in the near term (2017/18) come from:

- Replacement of interior lighting systems (279 GWh, 139 GWh, and 99 GWh respectively for screw-in, high bay, and linear fluorescent lighting systems)
- Installation of Energy Management Systems (155 GWh)
- HVAC equipment maintenance programs (155 GWh for AC maintenance and 36 GWh for heat pumps)
- Refrigerator decommissioning and recycling (134 GWh)
- Replacement of exterior lighting systems (97 GWh, 68 GWh, and 3 GWh respectively for screw-in, HID, and linear fluorescent lighting systems)

Together, these five categories of measures account for 1,166 MWh, roughly 62% of the Achievable - Low potential savings in the commercial sector in 2015. By 2030, non-equipment measures play a greater role in potential, led by energy management systems, refrigerator decommissioning, and roof-top equipment maintenance.

Table 6-9 Commercial Achievable - Low Savings for Equipment Measures (GWh)

End Use	Technology	2012/13	2017/18	2022/23	2027/28	2031/32
Cooling	Air-Cooled Chiller	0.0	1.0	3.6	7.0	8.9
	Other Cooling	0.0	0.2	0.6	1.0	1.2
	Roof Top AC	0.0	0.6	2.4	4.8	6.7
	Water-Cooled Chiller	0.0	2.2	7.6	15.0	19.0
Heating	Electric Heating	0.0	0.0	0.0	0.0	0.0
Cooling/Heating	Roof Top Heat Pump	0.0	1.7	4.5	6.8	8.7
Ventilation	Ventilation	0.0	14.1	37.2	55.3	60.7
Water Heating	Water Heating	0.0	12.3	31.6	57.9	71.9
Food Preparation	Dishwasher	0.0	0.4	1.1	1.8	2.1
	Fryer	0.0	0.2	0.5	0.8	1.0
	Hot Food Container	0.0	0.2	0.6	0.9	1.1
	Oven	0.0	0.4	0.9	1.5	1.8
Refrigeration	Glass Door Display	0.0	5.3	13.9	22.7	30.0
	Icemaker	0.0	0.1	0.2	0.4	0.5
	Open Display Case	0.0	0.4	1.2	2.0	2.8
	Reach-in Refrigerator	0.0	0.1	0.3	0.5	0.7
	Vending Machine	0.0	0.2	0.7	1.4	1.8
	Walk-in Refrigerator	0.0	1.0	3.0	5.2	7.1
Interior Lighting	High-Bay Fixtures	0.0	18.8	35.6	45.8	56.7
	Linear Fluorescent	0.0	8.1	103.2	230.0	290.6
	Screw-in	0.0	116.6	205.4	324.5	360.4
Exterior Lighting	HID	0.0	0.0	30.7	65.0	79.2
	Linear Fluorescent	0.0	0.0	0.0	0.0	0.0
	Screw-in	0.0	337.6	869.5	840.9	808.2
Office Equipment	Desktop Computer	0.0	9.9	15.8	18.0	19.1
	Laptop	0.0	1.4	2.3	2.6	2.8
	Monitor	0.0	0.3	0.5	0.6	0.6
	POS Terminal	0.0	0.0	0.0	0.0	0.0
	Printer/Copier/Fax	0.0	0.5	1.0	1.2	1.3
	Server	0.0	4.4	7.6	9.5	11.0
Miscellaneous	Miscellaneous	0.0	0.0	0.0	0.0	0.0
	Non-HVAC Motors	0.0	0.4	1.1	2.0	2.5
	Pool Heater	0.0	0.0	0.1	0.1	0.1
	Pool Pump	0.0	0.0	0.0	0.1	0.1
Subtotal	**Equipment**	**0.0**	**540.3**	**1,387.1**	**1,732.1**	**1,867.4**

Table 6-10 Commercial Achievable - Low Savings for Non-equipment Measures (GWh)

Measure	2012/13	2017/18	2022/23	2027/28	2031/32
Advanced New Construction Designs	1	11	36	54	67
Air Cooled Chiller - High Efficiency Fans	0	1	2	2	2
Air Cooled Chiller - Variable Speed Drive	1	10	14	13	12
Cool Roof	2	4	9	15	17
Custom Measures	1	3	11	30	54
Ducting - Repair & Sealing	2	10	18	20	21
Economizer - Installation	6	32	57	61	62
Energy Management System	13	27	40	42	42
Exterior Fluorescent - Bi-Level Fixture w/Occupancy Sensor	0	0	0	0	0
Exterior Lighting - Daylighting Controls	0	6	27	30	26
Fans - High Efficiency Motors	0	0	0	0	0
Glass Door Display - ECM	0	1	2	3	4
Glass Door Display - LED Lighting	4	10	18	21	22
Glass Door Display - Motion Sensors	0	0	0	0	0
Guestroom - Occupancy Sensors	0	0	0	0	0
HVAC - Occupancy Sensors	0	0	0	0	0
HVAC Commissioning	0	0	1	4	8
HVAC Retrocommissioning	17	38	61	74	75
Insulation - Ceiling	4	11	26	36	42
Insulation - Ducting	0	1	3	3	4
Insulation - Wall Cavity	4	12	24	31	35
Interior Fluorescent - Bi-Level Fixture w/Occupancy Sensor	0	0	0	0	0
Interior Fluorescent - Photocell Controlled Dimming Ballast	0	2	6	7	10
Interior Lighting - Daylighting Controls	10	48	71	60	60
Interior Lighting - LED Exit Signs	0	1	0	0	0
Interior Lighting - Occupancy Sensors	5	23	34	29	28
Interior Lighting - Task Lighting	0	1	3	4	5
Interior Lighting - Time Clocks and Timers	0	0	0	0	0
Lighting - Commissioning	0	0	1	5	10
Lighting - Retrocommissioning	5	20	27	21	19
Non-HVAC Motors - Variable Speed Control	0	0	0	0	0
Office Equipment - ENERGY STAR Power Supply	1	3	7	10	12
Office Equipment - Plug Load Occupancy Sensor	0	0	0	0	0
Open Display Case - Night Covers	0	0	0	0	0
Pool Pump - Timer	0	0	0	0	0
Pumps - High Efficiency Motors	0	1	5	7	7
Pumps - Variable Speed Control	1	5	9	12	13
Reach-in Refrigerator – De-commissioning and Recycling	0	0	1	1	0
Refrigeration - Anti-Sweat Heater	0	0	1	1	1

Measure	2012/13	2017/18	2022/23	2027/28	2031/32
Refrigeration - Door Gasket Replacement	0	1	2	2	3
Roof Top AC - Maintenance	1	8	17	18	19
Roof Top Heat Pump - Maintenance	3	16	29	32	33
Space Heating - Heat Recovery Ventilator	0	1	3	8	16
Thermostat - Clock/Programmable	3	9	16	19	20
Top Daylighting with Skylights	0	0	0	0	0
Vending Machine - Controller	0	0	0	0	0
Ventilation - CO2 Controlled	2	5	8	11	12
Ventilation - Exhaust Hood Sensor Control	0	0	1	1	1
Ventilation - Variable Speed Control	0	0	0	0	0
Water Cooled Chiller - Condenser Water Temperature Reset	0	0	0	0	1
Water Cooled Chiller - High Efficiency Fans	0	1	2	2	2
Water Cooled Chiller - Variable Speed Drive	2	12	14	13	12
Water Heating - Faucet Aerators	1	4	4	3	3
Water Heating - High Efficiency Circulation Pumps	0	1	5	7	8
Water Heating - Hot Water Saver	0	1	2	3	3
Water Heating - Pipe Insulation	0	0	0	1	1
Windows - High Efficiency	1	5	16	30	35
Total	**91**	**345**	**633**	**746**	**830**

Industrial Sector Potential

The industrial sector, at 8,122 GWh in 2010/11, accounts for over one-third of total electricity sales. Chemical products and primary metals are the two largest industries, accounting for 39% of total industrial sales in 2010/11. Because of their size, and in order to capture measures that are specific to these industries, we isolated them as separate segments.

Most of the equipment replacement opportunities are in the machine drive (motors) end use, but potential savings are diminishing due to the National Electrical Manufacturer's Association (NEMA) standards, which now make premium efficiency motors the baseline efficiency level. As a result, potential savings are only available from upgrading to still more efficient levels. Furthermore, due to the site-specific nature of many industrial sector process energy efficiency opportunities, savings potential resulting from these customized approaches should be characterized individually. To understand these opportunities in more depth, it would be appropriate to carry out site-specific engineering assessments for each customer, though we would recommend that such assessments be limited to only the very largest customers.

Throughout the study period, Economic potential is about 80%–90% of Technical potential, indicating that most of the measures evaluated are cost-effective. In 2015, Achievable - Low potential is 826 GWh or 1.7% of the baseline industrial forecast. By 2030, it increases to 5,229 GWh, or 9.8% of the baseline forecast and 43% of economic potential. Table 6-11, Figure 6-7 and Figure 6-8 present the savings for the various types of potential considered in this study.

Table 6-11 Energy Efficiency Potential for the Industrial Sector

	2012/13	2017/18	2022/23	2027/28	2031/32
Baseline Forecast (GWh)	**8,122**	**8,462**	**8,910**	**9,392**	**9,687**
Energy Forecasts (GWh)					
Energy Savings (GWh)					
Realistic Achievable Potential	0	104	252	328	370
Maximum Achievable Potential	1	268	575	729	812
Economic Potential	44	389	711	895	992
Technical Potential	57	425	807	1,070	1,233
Energy Savings (% of Baseline)					
Realistic Achievable Potential	0.0%	1.2%	2.8%	3.5%	3.8%
Maximum Achievable Potential	0.0%	3.2%	6.4%	7.8%	8.4%
Economic Potential	0.5%	4.6%	8.0%	9.5%	10.2%
Technical Potential	0.7%	5.0%	9.1%	11.4%	12.7%

Figure 6-7 Industrial Energy Efficiency Potential Savings

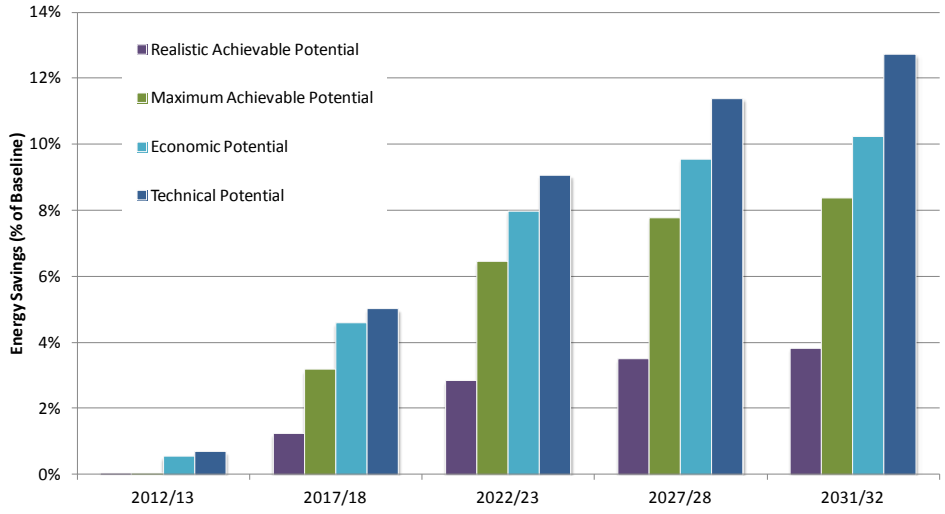
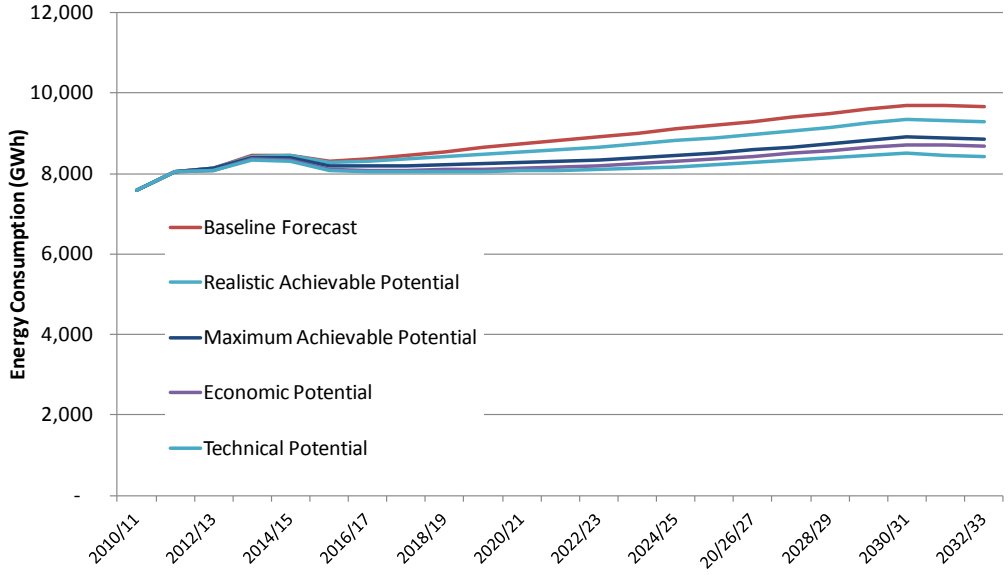


Figure 6-8 Industrial Energy Efficiency Potential Forecast



Industrial Potential by End Use

Table 6-12 presents the industrial savings by end use and type of potential. As mentioned above, machine drives offer the greatest opportunity for energy savings across the range of potential. Lighting has the next highest savings potential, particularly in the near term, but is ultimately dwarfed in comparison to the opportunities for machine drives.

Table 6-12 Industrial Potential by End Use and Potential Type (GWh)

		2012/13	2017/18	2022/23	2027/28	2031/32
Cooling	Achievable Low Potential	0	14	39	55	63
	Achievable High Potential	0	31	79	110	125
	Economic Potential	19	52	100	139	156
	Technical Potential	21	59	117	168	195
Space Heating	Achievable Low Potential	-	5	14	19	21
	Achievable High Potential	-	12	28	36	40
	Economic Potential	7	18	33	43	46
	Technical Potential	7	18	33	43	47
Ventilation	Achievable Low Potential	0	1	3	4	5
	Achievable High Potential	0	2	9	11	12
	Economic Potential	0	3	11	14	15
	Technical Potential	0	3	11	15	15
Interior Lighting	Achievable Low Potential	0	13	34	48	57
	Achievable High Potential	0	30	64	85	100
	Economic Potential	4	45	77	101	118
	Technical Potential	6	49	85	117	141
Exterior Lighting	Achievable Low Potential	-	2	7	9	10
	Achievable High Potential	-	5	15	19	20
	Economic Potential	0	7	17	22	23
	Technical Potential	0	7	17	22	23
Pumps	Achievable Low Potential	0	14	32	40	45
	Achievable High Potential	0	41	82	102	113
	Economic Potential	3	58	103	127	140
	Technical Potential	4	65	132	166	185
Fans & Blowers	Achievable Low Potential	0	16	36	43	47
	Achievable High Potential	0	32	65	79	87
	Economic Potential	3	44	79	97	106
	Technical Potential	4	47	85	106	121
Compressed Air	Achievable Low Potential	0	8	19	24	27
	Achievable High Potential	0	24	49	62	68
	Economic Potential	2	35	62	77	85
	Technical Potential	3	38	69	91	106
Conveyors	Achievable Low Potential	0	5	12	15	16
	Achievable High Potential	0	16	33	39	42
	Economic Potential	1	21	39	47	50
	Technical Potential	2	23	43	54	60
Other Motors	Achievable Low Potential	0	26	57	72	80
	Achievable High Potential	0	75	152	186	205
	Economic Potential	6	106	189	230	252
	Technical Potential	9	113	203	257	292

Process Heating	Achievable Low Potential	-	-	-	-	-
	Achievable High Potential	-	-	-	-	-
	Economic Potential	-	-	-	-	-
	Technical Potential	-	-	-	-	-
Process Cooling & Refrigeration	Achievable Low Potential	-	-	-	-	-
	Achievable High Potential	-	-	-	-	-
	Economic Potential	-	-	-	-	-
	Technical Potential	1	3	12	31	48
Elctro-chemical Processes	Achievable Low Potential	-	-	-	-	-
	Achievable High Potential	-	-	-	-	-
	Economic Potential	-	-	-	-	-
	Technical Potential	-	-	-	-	-
Other Process	Achievable Low Potential	-	-	-	-	-
	Achievable High Potential	-	-	-	-	-
	Economic Potential	-	-	-	-	-
	Technical Potential	-	-	-	-	-
Miscellaneous	Achievable Low Potential	-	-	-	-	-
	Achievable High Potential	-	-	-	-	-
	Economic Potential	-	-	-	-	-
	Technical Potential	-	-	-	-	-
Total	**Achievable Low Potential**	**0**	**104**	**252**	**328**	**370**
	Achievable High Potential	**1**	**268**	**575**	**729**	**812**
	Economic Potential	**44**	**389**	**711**	**895**	**992**
	Technical Potential	**57**	**425**	**807**	**1,070**	**1,233**

CHAPTER | 7

ENERGY EFFICIENCY POTENTIAL FOR NATURAL GAS

This chapter presents the results of the energy-efficiency analysis for natural gas. First, the overall potential is presented, followed by results for each sector.

Overall Energy Efficiency Potential

Table 6-1 presents the baseline forecasts of energy consumption, as well as the levels of natural gas energy-efficiency potential across sectors. As discussed in detail in Chapter 4, the baseline forecast across all sectors increases over the 20-year study period of 2012/13 to 2031/32. The growth is highest in the residential sector, although all sectors have somewhat tempered forecasts due to appliance and equipment standards, building codes, and a sluggish economy in the near term. Key findings related to potentials are summarized below.

- **Achievable - Low potential** forms a lower point on the range of achievable potential. Across all sectors, this metric is 106 MMm3 in 2017/18 and increases to 324 MMm3 by 2031/32. This represents 6.9% of the baseline forecast in 2017/18 and 21.2% in 2031/32.
- **Achievable - High potential** forms the upper bound on the range of achievable potential. It is 136 MMm3 in 2017/18, which represents 8.9% of the baseline forecast. By 2031/32, the cumulative savings are 412 MMm3, 27% of the baseline forecast.
- **Economic potential**, which reflects the savings when all cost-effective measures are taken, is 202 MMm3 in 2017/18. This represents 13.2% of the baseline energy forecast. By 2031/32, economic potential reaches 561 MMm3, 36.8% of the baseline energy forecast.
- **Technical potential**, which reflects the adoption of all energy efficiency measures regardless of cost-effectiveness, is a theoretical upper bound on savings. In 2017/18, energy savings are 239 MMm3, or 15.7% of the baseline energy forecast. By 2031/32, technical potential reaches 635 MMm3 41.6% of the baseline energy forecast.

Table 7-1 summarizes the energy-efficiency savings for the different levels of potential relative to the baseline forecast. Figure 7-1 displays the energy-efficiency forecasts.

Table 7-1 Summary of Energy Efficiency Potential

	2012/13	2017/18	2022/23	2027/28	2031/32
Baseline Forecast (MMm3)	1,526	1,526	1,542	1,563	1,587
Natural Gas Savings (MMm3)					
Achievable Low Potential	6	106	214	292	324
Achievable High Potential	10	136	281	375	412
Economic Potential	51	202	386	507	561
Technical Potential	64	239	446	578	635
Natural Gas Savings (% of Baseline)					
Achievable Low Potential	0.4%	6.9%	14.0%	19.1%	21.2%
Achievable High Potential	0.7%	8.9%	18.4%	24.6%	27.0%
Economic Potential	3.4%	13.2%	25.3%	33.2%	36.8%
Technical Potential	4.2%	15.7%	29.3%	37.9%	41.6%

Figure 7-1 Summary of Achievable Potential Energy Savings

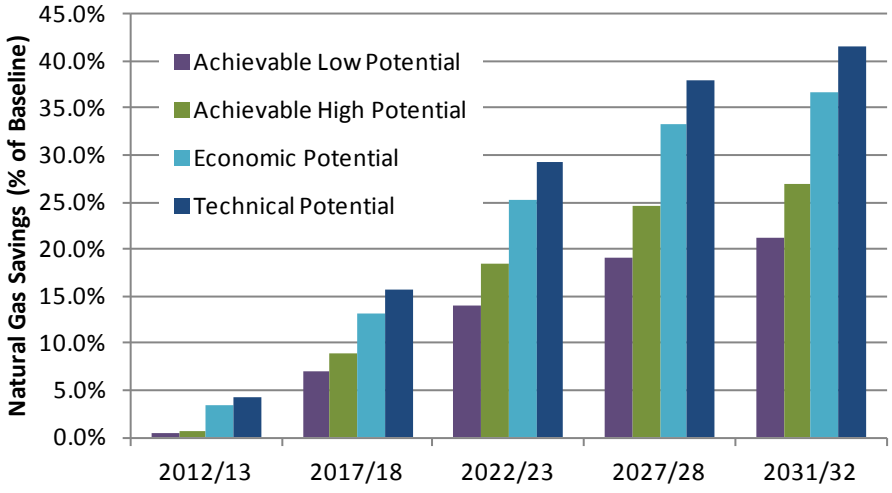


Table 7-2 summarizes the range of achievable potential by sector. The residential sector accounts for the largest portion of the savings, followed by the commercial and then the industrial sectors.

Table 7-2 Achievable Energy-efficiency Potential by Sector (MMm3)

	2012/13	2017/18	2022/23	2027/28	2031/32
Achievable - Low Savings (GWh)					
Residential	6	84	153	213	238
Commercial	0	1	2	3	4
Industrial	-	21	59	76	83
Total	**6**	**106**	**214**	**292**	**324**
Achievable - High Savings (GWh)					
Residential	10	87	160	220	245
Commercial	0	3	5	6	7
Industrial	-	47	116	148	160
Total	**10**	**136**	**281**	**375**	**412**

Residential Sector

Table 7-3 presents estimates for the four types of potential. Figure 7-3 depicts the potential energy savings estimates graphically.

- **Achievable - Low potential** projects 84 MMm3 of energy savings in 2017/18, 15.2% of the baseline forecast. This increases to 238 MMm3, 43.1% of the baseline forecast, in 2031/32.
- **Achievable - High potential** is 87 MMm3 in 2017/18, which represents 15.7% of the baseline forecast. By 2031/32, the cumulative energy savings are 245 MMm3, 44.4% of the baseline forecast.
- **Economic potential,** which reflects the savings when all cost-effective measures are taken, is 90 MMm3 in 2017/18. This represents 16.4% of the baseline energy forecast. By 2031/32, economic potential reaches 253 MMm3, 46% of the baseline energy forecast.
- **Technical potential,** which reflects the adoption of all energy efficiency measures regardless of cost is a theoretical upper bound on savings. In 2017/18, energy savings are 109 MMm3, or 19.7% of the baseline energy forecast. By 2031/32, technical potential reaches 286 MMm3, 51.9% of the baseline energy forecast.

Table 7-3 Electricity Energy Efficiency Potential for the Residential Sector

	2012/13	2017/18	2022/23	2027/28	2031/32
Baseline Forecast (MMm3)	**559**	**552**	**549**	**549**	**551**
Natural Gas Savings (MMm3)					
Achievable Low Potential	6	84	153	213	238
Achievable High Potential	10	87	160	220	245
Economic Potential	17	90	170	229	253
Technical Potential	23	109	199	263	286
Natural Gas Savings (% of Baseline)					
Achievable Low Potential	1.1%	15.2%	27.8%	38.7%	43.1%
Achievable High Potential	1.8%	15.7%	29.2%	40.1%	44.4%
Economic Potential	3.1%	16.4%	30.9%	41.7%	46.0%
Technical Potential	4.2%	19.7%	36.3%	47.9%	51.9%

Figure 7-2 Residential Energy Efficiency Potential Savings

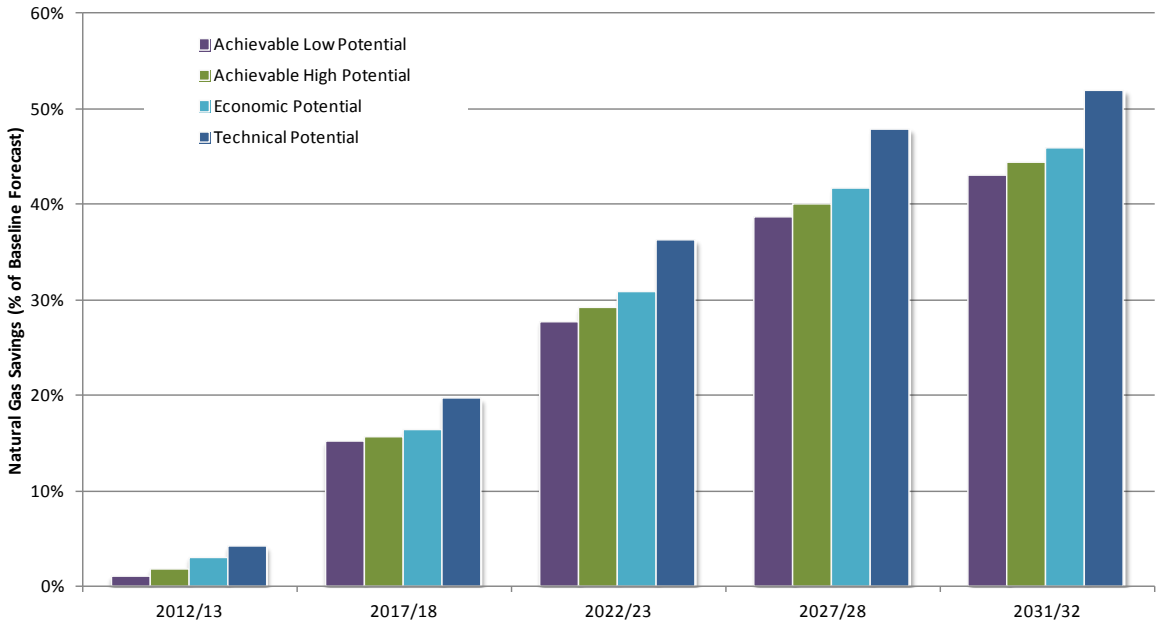
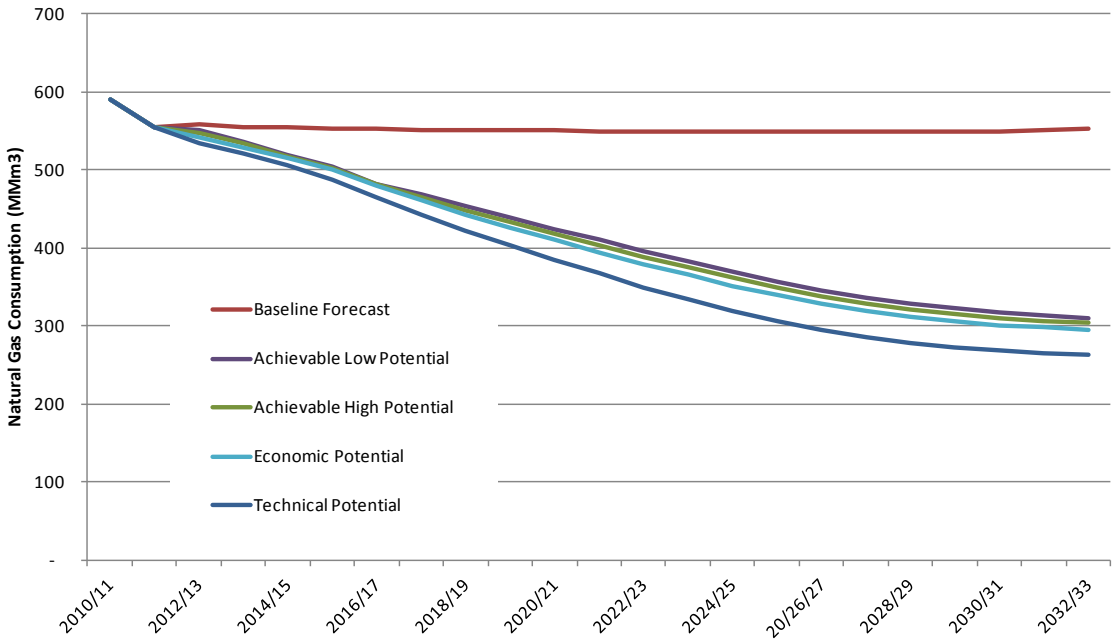


Figure 7-3 Residential Energy Efficiency Potential Forecast



Residential Potential by End Use, Technology, and Measure Type

Table 7-4 provides estimates of savings for each end use and type of potential. Focusing first on technical and economic potential, there are significant savings that are both possible and economic in numerous end uses:

- **Water Heating** offers the highest technical potential, which reflects the across the board-installation of solar water heating. However, solar water heating does not become cost-effective, using the study's assumptions of equipment cost and avoided cost, during the forecast period. The technology with the next highest efficiency is the heat pump water heater (HPWH). HPWH's are cost effective throughout the entire study, and drive high

economic potentials as a result. Also included in water heating potentials are measures such as faucet aerators and low flow showerheads.

- **Appliances** also have significant technical potential savings. This reflects both the replacement of failed white-goods appliances with the highest-efficiency option and removal of second refrigerators in appliance recycling programs.

Table 7-4 Residential Savings by End Use and Potential Type (MMm3)

End Use	Case	2012/13	2017/18	2022/23	2027/28	2031/32
Heating	Achievable Low Potential	5.5	68.3	132.9	192.7	218.5
	Achievable High Potential	9.0	70.1	138.0	197.8	223.4
	Economic Potential	15.4	71.9	143.7	203.3	228.8
	Technical Potential	19.6	82.1	161.9	222.6	246.9
Water Heating	Achievable Low Potential	0.9	15.5	19.6	19.6	18.9
	Achievable High Potential	1.2	16.5	22.0	22.0	21.1
	Economic Potential	1.9	18.2	25.3	25.1	23.7
	Technical Potential	3.5	25.5	35.4	37.7	36.3
Appliances	Achievable Low Potential	-	-	-	-	-
	Achievable High Potential	-	-	-	-	-
	Economic Potential	-	-	-	-	-
	Technical Potential	0.0	0.1	0.3	0.3	0.4
Miscellaneous	Achievable Low Potential	0.0	0.0	0.1	0.3	0.5
	Achievable High Potential	0.0	0.1	0.2	0.4	0.6
	Economic Potential	0.0	0.3	0.6	0.9	1.0
	Technical Potential	0.1	0.9	1.7	2.5	2.9
Total	**Achievable Low Potential**	**6.4**	**83.8**	**152.6**	**212.6**	**237.9**
	Achievable High Potential	**10.2**	**86.6**	**160.2**	**220.1**	**245.1**
	Economic Potential	**17.3**	**90.5**	**169.6**	**229.3**	**253.5**
	Technical Potential	**23.2**	**108.6**	**199.3**	**263.3**	**286.4**

As described in Chapter 2, using our LoadMAP model, we develop separate estimates of potential for equipment and non-equipment measures. Table 7-5 presents Achievable – Low results for equipment at the technology level and Table 7-6 presents non-equipment measures for which Achievable - Low potential is greater than zero. The majority of the savings come from the non-equipment measures, with shell measures leading the way.

Table 7-5 Residential Achievable - Low Potential by Technology – Selected years (MMm3)

End Use	Technology	2012/13	2017/18	2022/23	2027/28	2031/32
Heating	Furnace	-	-	-	-	0.40
	Boiler	-	-	-	-	-
	Supplemental Heat	-	-	-	-	-
Water Heating	Water Heater	0.42	1.43	1.42	1.25	0.36
Appliances	Clothes Dryer	-	-	-	-	-
	Stove	-	-	-	-	-
Miscellaneous	Pool Heater	0.05	0.30	0.59	0.86	0.98
	Gas Barbeque	-	-	-	-	-
	Miscellaneous	-	-	-	-	-
Equipment Total		**0.46**	**1.73**	**2.01**	**2.11**	**1.74**
Equipment and Measures Total		**17.29**	**90.46**	**169.60**	**229.31**	**253.46**

Table 7-6 Residential Achievable - Low Savings for Non-equipment Measures (MMm3)

Measure	2012	2015	2020	2025	2030
Advanced New Construction Design	-	-	-	-	-
Attic Fan - Installation	-	-	-	-	-
Attic Fan - Photovoltaic	-	-	-	-	-
Ceiling Fan - Installation	0.4	1.9	15.1	49.0	81.6
Central AC - Maintenance	-	-	-	-	0.3
Central Heat Pump - Maintenance	1.1	8.2	95.7	236.0	307.1
Dehumidifier	-	-	-	-	-
Doors - Storm and Thermal	-	-	-	-	-
Ducting - Repair and Sealing	1.7	11.9	132.8	320.8	413.8
Energy Efficient Manufactured Home	-	-	-	-	-
ENERGY STAR Homes	-	-	-	-	-
Exterior Lighting - Photosensor Control	-	-	-	-	-
Exterior Lighting - Photovoltaic - Installation	-	-	-	-	-
Exterior Lighting - Timeclock Installation	-	-	-	-	-
Freezer - Maintenance	-	-	-	-	-
Freezer - Remove Second Unit	1.4	4.2	17.9	60.3	133.2
Home Electronics - Reduce Standby Wattage	0.1	4.0	177.4	248.1	284.6
Home Energy Management System	1.4	5.9	47.2	195.1	388.4
Insulation – Ceiling	0.2	1.2	11.2	52.8	122.6
Insulation – Ducting	-	-	-	0.3	2.1
Insulation – Foundation	0.0	0.3	4.3	21.2	45.0
Insulation - Infiltration Control	0.9	3.6	25.8	119.2	298.7
Insulation - Wall Cavity	0.0	0.4	5.2	32.7	96.3
Insulation - Wall Sheathing	0.0	0.1	0.8	4.1	8.9
Interior Lighting - Occupancy Sensor	-	-	-	-	0.0
Pool - Pump Timer	0.0	0.4	2.8	12.0	27.2
Refrigerator - Maintenance	-	-	-	-	-
Refrigerator - Remove Second Unit	72.9	104.1	132.3	194.6	279.1
Roofs - High Reflectivity	-	-	-	-	-
Spa - Pump Timer	-	-	-	-	-
Thermostat - Clock/Programmable	0.7	3.5	34.2	110.9	165.3
Water Heater - Drainwater Heat Recovery	-	-	-	-	-
Water Heater - Faucet Aerators	0.7	3.8	22.8	58.1	78.5
Water Heater - Hot Water Saver	0.4	1.8	8.8	30.4	79.0
Water Heater - Low-Flow Showerheads	1.1	5.8	35.1	90.3	123.4
Water Heater - Pipe Insulation					
Water Heater - Tank Blanket/Insulation	1.1	7.8	49.5	78.3	78.1
Water Heater - Thermostat Setback	1.8	9.7	59.3	170.8	260.4
Water Heater - Timer	-	-	-	-	-
Whole-House Fan - Installation	-	0.0	0.2	0.6	1.9
Windows - ENERGY STAR	0.6	3.0	36.6	145.0	318.1
Windows - Install reflective film	-	-	-	0.1	0.7
Subtotal Non-Equipment Measures	**86**	**181**	**915**	**2,230**	**3,593**
Total Equipment and Non-Equipment Measures	**384**	**1,444**	**3,216**	**5,652**	**8,307**

Note: Values shown as 0.0 are non-zero but are very small.

Commercial Sector Potential

The baseline forecast for the commercial sector has moderate growth and the opportunity for energy-efficiency savings is still significant for the commercial sector.

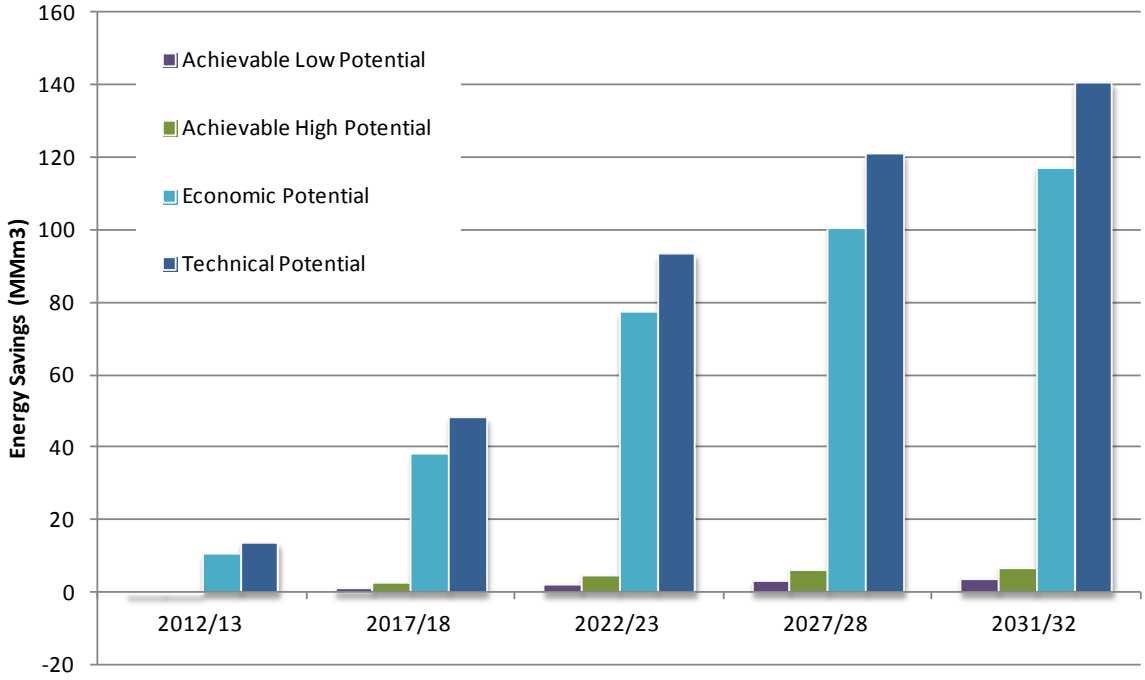
- **Achievable - Low potential** projects 1 MMm3 of energy savings in 2017/18 and 4 MMm3 in 2031/32. This corresponds to 0% of the baseline forecast in 2017/18 and 1% in 2031/32.
- **Achievable - High potential** is 3 MMm3 in 2017/18, which represents 1% of the baseline forecast. By 2031/32, the cumulative energy savings are 7 MMm3, 2% of the baseline forecast.
- **Economic potential**, which reflects the savings when all cost-effective measures are taken, is 38 MMm3 in 2017/18. This represents 9% of the baseline energy forecast. By 2031/32, economic potential reaches 117 MMm3, 26% of the baseline energy forecast.
- **Technical potential,** which reflects the adoption of all energy efficiency measures regardless of cost, is a theoretical upper bound on savings. In 2017/18, energy savings are 48 MMm3 GWh, or 11% of the baseline energy forecast. By 2031/32, technical potential reaches 141 MMm3, 31% of the baseline energy forecast.

Table 7-7 and Figure 7-4 present the savings associated with each level of potential.

Table 7-7 Energy Efficiency Potential for the Commercial Sector

Gas Summary	2012/13	2017/18	2022/23	2027/28	2031/32
Baseline Forecast (MMm3)	**451**	**445**	**445**	**447**	**457**
Natural Gas Savings (MMm3)					
Achievable Low Potential	0	1	2	3	4
Achievable High Potential	0	3	5	6	7
Economic Potential	10	38	77	101	117
Technical Potential	14	48	93	121	141
Natural Gas Savings (% of Baseline)					
Achievable Low Potential	0%	0%	0%	1%	1%
Achievable High Potential	0%	1%	1%	1%	2%
Economic Potential	2%	9%	17%	23%	26%
Technical Potential	3%	11%	21%	27%	31%

Figure 7-4 Commercial Energy Efficiency Potential Savings



Commercial Potential by End Use, Technology, and Measure Type

Table 7-8 presents the commercial sector savings by end use and potential type. The end uses with the highest technical and economic potential are:

- Space heating, as a result of higher efficiency furnaces and boilers. In addition, several shell measures contribute to the savings.
- Other savings come from food preparation and water heating.

Table 7-9 and Table 7-10 focus on achievable potential savings.

Table 7-8 Commercial Potential by End Use and Potential Type (MMm3)

End Use	Case	2012/13	2017/18	2022/23	2027/28	2031/32
Space Heating	Achievable Low Potential	0.0	0.1	0.2	0.4	0.6
	Achievable High Potential	0.0	0.4	0.6	0.9	1.2
	Economic Potential	8.9	30.8	66.7	90.5	106.7
	Technical Potential	11.9	39.7	81.4	109.5	129.2
Water Heating	Achievable Low Potential	0.0	0.3	0.3	0.1	0.0
	Achievable High Potential	0.0	0.9	0.9	0.3	0.0
	Economic Potential	1.1	4.4	5.2	3.7	3.7
	Technical Potential	1.4	5.5	6.7	4.9	4.7
Food Preparation	Achievable Low Potential	0.0	0.6	1.5	2.5	2.9
	Achievable High Potential	0.0	1.4	3.3	5.0	5.7
	Economic Potential	0.4	3.0	5.3	6.4	6.8
	Technical Potential	0.4	3.0	5.3	6.4	6.8
Miscellaneous	Achievable Low Potential	0.0	0.0	0.0	0.0	0.0
	Achievable High Potential	0.0	0.0	0.0	0.0	0.0
	Economic Potential	0.0	0.0	0.0	0.0	0.0
	Technical Potential	0.0	0.0	0.0	0.1	0.1
Total	**Achievable Low Potential**	**0.0**	**1.1**	**2.1**	**3.0**	**3.5**
	Achievable High Potential	**0.0**	**2.7**	**4.8**	**6.1**	**6.9**
	Economic Potential	**10.4**	**38.2**	**77.3**	**100.6**	**117.2**
	Technical Potential	**13.7**	**48.2**	**93.5**	**120.9**	**140.8**

Table 7-9 and Table 7-10 present achievable potential savings for equipment measures and non-equipment measures, respectively, under the Achievable - Low case.

Table 7-9 Commercial Achievable - Low Savings for Equipment Measures (MMm3)

		2012/13	2017/18	2022/23	2027/28	2031/32
Space Heating	Achievable Low Potential	0.0	0.1	0.2	0.4	0.6
	Achievable High Potential	0.0	0.4	0.6	0.9	1.2
	Economic Potential	0.4	1.2	1.4	1.8	2.1
	Technical Potential	1.3	5.4	6.9	8.2	9.4
Water Heating	Achievable Low Potential	0.0	0.3	0.3	0.1	0.0
	Achievable High Potential	0.0	0.9	0.9	0.3	0.0
	Economic Potential	0.8	2.8	2.7	0.5	0.0
	Technical Potential	1.0	3.5	3.4	0.7	0.0
Food Preparation	Achievable Low Potential	(0.0)	0.6	1.5	2.5	2.9
	Achievable High Potential	(0.0)	1.4	3.3	5.0	5.7
	Economic Potential	0.4	3.0	5.3	6.4	6.8
	Technical Potential	0.4	3.0	5.3	6.4	6.8
Miscellaneous	Achievable Low Potential	0.0	0.0	0.0	0.0	0.0
	Achievable High Potential	0.0	0.0	0.0	0.0	0.0
	Economic Potential	0.0	0.0	0.0	0.0	0.0
	Technical Potential	0.0	0.0	0.0	0.1	0.1
Total	**Achievable Low Potential**	**(0.0)**	**1.1**	**2.1**	**3.0**	**3.5**
	Achievable High Potential	**(0.0)**	**2.7**	**4.8**	**6.1**	**6.9**
	Economic Potential	**1.6**	**7.0**	**9.4**	**8.7**	**8.9**
	Technical Potential	**2.7**	**11.9**	**15.7**	**15.3**	**16.3**

Table 7-10 Commercial Achievable - Low Savings for Non-equipment Measures (MMm3)

Measure	2012/13	2017/18	2022/23	2027/28	2031/32
Advanced New Construction Designs	0.1	1.0	3.6	5.8	7.2
Custom Measures	0.1	0.5	1.6	4.5	8.0
Ducting - Repair & Sealing	0.3	1.4	2.6	2.8	3.0
Energy Management System	1.2	2.9	4.7	5.4	5.5
Gas Boiler - Maintenance	0.3	2.3	6.7	7.9	8.2
Gas Boiler - High Efficiency Hot Water Circulation	0.0	0.1	0.4	1.0	1.3
Gas Boiler - Hot Water Reset	0.1	0.4	1.2	2.8	3.8
Gas Furnace - Maintenance	0.5	5.0	12.9	13.7	13.6
HVAC - Occupancy Sensors	0.0	0.0	0.0	0.0	0.0
HVAC Commissioning	0.0	0.0	0.1	0.5	1.0
HVAC Retrocommissioning	3.3	7.8	12.7	14.9	15.2
Insulation - Ceiling	0.8	2.4	5.0	6.8	7.7
Insulation - Ducting	0.0	0.1	0.2	0.3	0.3
Insulation - Wall Cavity	0.7	1.8	3.6	4.7	5.2
Space Heating - Heat Recovery Ventilator	0.2	0.7	1.9	5.2	10.9
Thermostat - Clock/Programmable	0.6	1.8	3.0	3.6	3.9
Water Heating - Faucet Aerators	0.2	1.3	1.6	1.6	1.6
Water Heating - Hot Water Saver	0.1	0.3	0.8	1.3	1.5
Water Heating - Pipe Insulation	0.0	0.0	0.1	0.4	0.6
Windows - High Efficiency	0.3	1.4	4.7	8.7	9.9
Measures Total	**8.8**	**31.1**	**67.8**	**91.9**	**108.4**
% of Total Equipment and Non-Equipment Measures	**85%**	**82%**	**88%**	**91%**	**92%**

Industrial Sector Potential

The industrial sector, at 509 MMm3 in 2010/11, accounts for over one-third of total natural gas sales. Chemical products and primary metals are the two largest industries, accounting for 39% of total industrial sales in 2010/11.

Most of the equipment replacement opportunities are in the heating or process heating end uses. Throughout the study period, Economic potential is about 80%–90% of Technical potential, indicating that most of the measures evaluated are cost-effective. In 2017/18, Achievable - Low potential is 21 MMm3 or 4% of the baseline industrial forecast. By 2031/32, it increases to 83 MMm3, or 14% of the baseline forecast. Table 7-11, Figure 7-5 and Figure 7-6 present the savings for the various types of potential considered in this study.

Table 7-11 Energy Efficiency Potential for the Industrial Sector

	2012/13	2017/18	2022/23	2027/28	2031/32
Baseline Forecast (10^6 m3)	**517**	**529**	**547**	**567**	**579**
Natural Gas Savings (10^6 m3)					
Achievable Low Potential	-	21	59	76	83
Achievable High Potential	-	47	116	148	160
Economic Potential	24	73	139	177	190
Technical Potential	27	82	154	194	208
Natural Gas Savings (% of Baseline)					
Achievable Low Potential	0%	4%	11%	13%	14%
Achievable High Potential	0%	9%	21%	26%	28%
Economic Potential	5%	14%	25%	31%	33%
Technical Potential	5%	15%	28%	34%	36%

Figure 7-5 Industrial Energy Efficiency Potential Savings

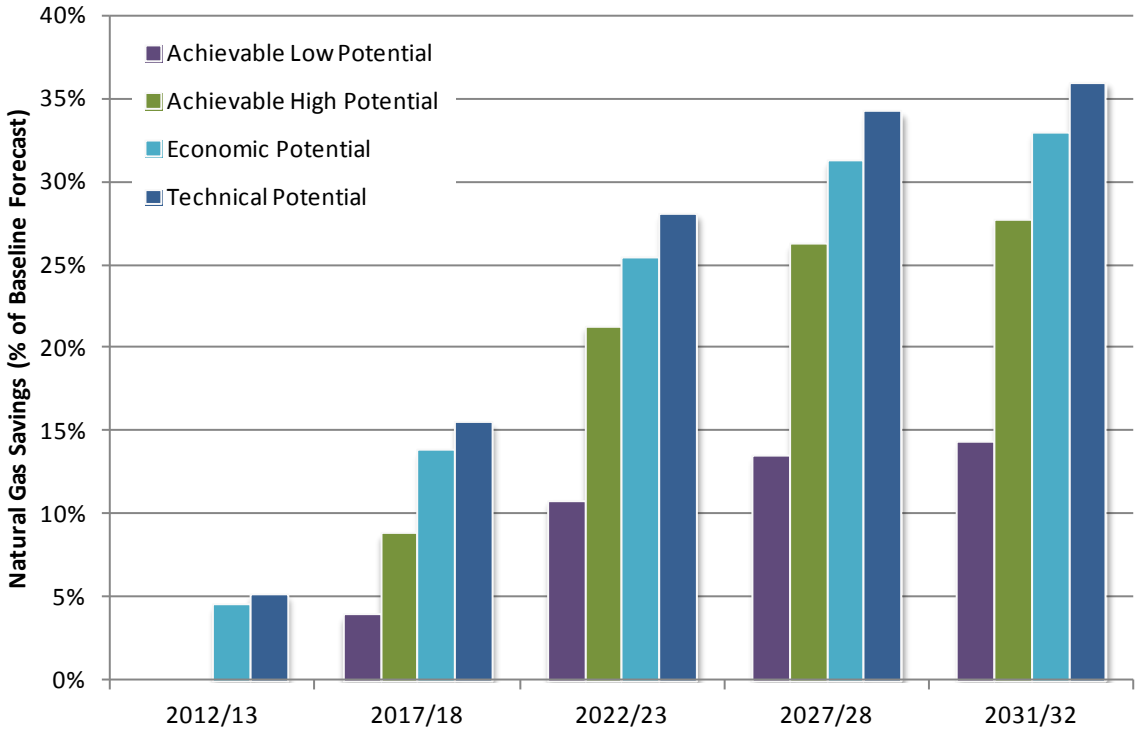
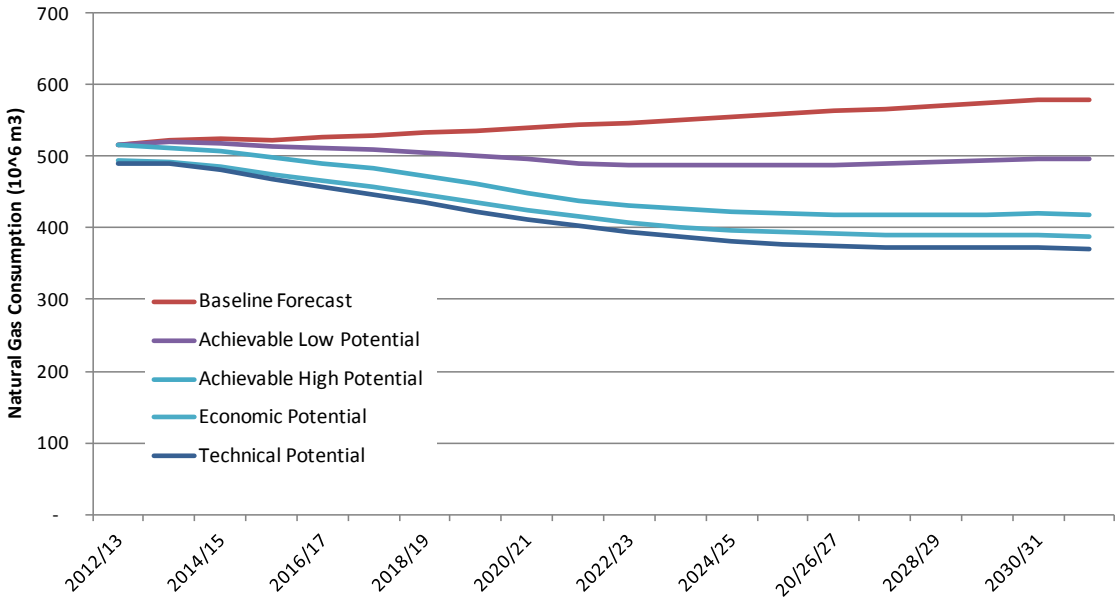


Figure 7-6 Industrial Energy Efficiency Potential Forecast



Industrial Potential by End Use

Table 7-12 presents the industrial savings by end use and type of potential. As mentioned above, heating offers the greatest opportunity for energy savings across the range of potential.

Table 7-12 Industrial Potential by End Use and Potential Type (MMm3)

		2012/13	2017/18	2022/23	2027/28	2031/32
Heating	Achievable Low Potential	0	19	48	69	74
	Achievable High Potential	0	42	104	133	144
	Economic Potential	22	66	124	159	172
	Technical Potential	26	75	139	176	190
Process Heating	Achievable Low Potential	0	2	6	8	8
	Achievable High Potential	0	4	13	15	16
	Economic Potential	1	7	15	18	18
	Technical Potential	1	7	15	18	18
Process Cooling	Achievable Low Potential	0	0	0	0	0
	Achievable High Potential	0	0	0	0	0
	Economic Potential	0	0	0	0	0
	Technical Potential	0	0	0	0	0
Other Process	Achievable Low Potential	0	0	0	0	0
	Achievable High Potential	0	0	0	0	0
	Economic Potential	0	0	0	0	0
	Technical Potential	0	0	0	0	0
Miscellaneous	Achievable Low Potential	0	0	0	0	0
	Achievable High Potential	0	0	0	0	0
	Economic Potential	0	0	0	0	0
	Technical Potential	0	0	0	0	0
Total	**Achievable Low Potential**	**0**	**21**	**54**	**77**	**82**
	Achievable High Potential	**0**	**46**	**117**	**148**	**160**
	Economic Potential	**23**	**73**	**139**	**177**	**190**
	Technical Potential	**27**	**82**	**154**	**194**	**208**

APPENDIX | A

SAMPLE APPENDIX A TITLE

About EnerNOC Utility Solutions Consulting

EnerNOC Utility Solutions Consulting is part of EnerNOC Utility Solutions group, which provides a comprehensive suite of demand-side management (DSM) services to utilities and grid operators worldwide. Hundreds of utilities have leveraged our technology, our people, and our proven processes to make their energy efficiency (EE) and demand response (DR) initiatives a success. Utilities trust EnerNOC to work with them at every stage of the DSM program lifecycle – assessing market potential, designing effective programs, implementing those programs, and measuring program results.

EnerNOC Utility Solutions delivers value to our utility clients through two separate practice areas – Program Implementation and EnerNOC Utility Solutions Consulting.

- Our Program Implementation team leverages EnerNOC's deep "behind-the-meter expertise" and world-class technology platform to help utilities create and manage DR and EE programs that deliver reliable and cost-effective energy savings. We focus exclusively on the commercial and industrial (C&I) customer segments, with a track record of successful partnerships that spans more than a decade. Through a focus on high quality, measurable savings, EnerNOC has successfully delivered hundreds of thousands of MWh of energy efficiency for our utility clients, and we have thousands of MW of demand response capacity under management.
- The EnerNOC Utility Solutions Consulting team provides expertise and analysis to support a broad range of utility DSM activities, including: potential assessments; end-use forecasts; integrated resource planning; EE, DR, and smart grid pilot and program design and administration; load research; technology assessments and demonstrations; evaluation, measurement and verification; and regulatory support.

The EnerNOC Utility Solutions Consulting team has decades of combined experience in the utility DSM industry. The staff is comprised of professional electrical, mechanical, chemical, civil, industrial, and environmental engineers as well as economists, business planners, project managers, market researchers, load research professionals, and statisticians. Utilities view our experts as trusted advisors, and we work together collaboratively to make any DSM initiative a success.

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Demand Side Management Potential Study

Report Number #1369

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CHAPTER | 1

INTRODUCTION

Background

Manitoba Hydro engaged EnerNOC (formerly Global Energy Partners), to conduct a study to assess 20-year potentials of energy efficiency (EE) for electricity and natural gas. This potential study will provide information to assist Manitoba Hydro in refining their Power Smart program portfolio.

Toward this end, EnerNOC conducted a detailed, bottom-up assessment of the Manitoba Hydro market to deliver forecasts of energy use and peak demand, as well as forecasts of energy and peak-demand savings achievable through energy efficiency programs. The 20-year potentials study addresses the residential, commercial, and industrial sectors.

Definitions of Potential

In this study, we estimate the potential for energy efficiency savings. The savings estimates represent three types of potential: technical potential, economic potential, and achievable potential. Technical and economic potential are both theoretical limits to efficiency savings. Achievable potential embodies a set of assumptions about the decisions consumers make regarding the efficiency of the equipment they purchase, the maintenance activities they undertake, the controls they use for energy-consuming equipment, and the elements of building construction. Because estimating achievable potential involves the inherent uncertainty of predicting human behaviors and responses to market conditions, we developed low and high achievable potential as boundaries for a likely range. For this reason, we developed a range of achievable potential. These levels are described below.

- **Technical potential** is defined as the theoretical upper limit of energy efficiency potential. It assumes that customers adopt all feasible measures regardless of their cost. At the time of existing equipment failure, customers replace their equipment with the most efficient option available. In new construction, customers and developers also choose the most efficient equipment option. Examples of measures that make up technical potential in the residential sector include geothermal heat pumps and LED lighting.

  Technical potential also assumes the adoption of every available other measure, where applicable. For example, it includes installation of high-efficiency windows in all new construction opportunities and heating system maintenance in all existing buildings. The retrofit measures are phased in over a number of years, which is longer for higher-cost and complex measures.

- **Economic potential** represents the adoption of all **cost-effective** energy efficiency measures. In this analysis, the cost effectiveness is measured by the total resource cost (TRC) test, which compares lifetime energy and capacity benefits to the incremental cost of the measure. If the benefits outweigh the costs (that is, if the TRC ratio is greater than 1.0), then a given measure is included in economic potential. As with technical potential, all customers, to whom the measure applies, purchase the most efficient option with a B/C ratio of 1.0 or higher.

- **Market potential** is the subset of economic potential that can be obtained through efficiency programs under ideal market, implementation, regulatory and customer preference conditions. Information channels are assumed to be established and efficient for marketing, educating consumers, and coordinating with trade allies and delivery partners. The only barrier is customer preferences for the technology or measure (e.g., some customers don't like CFL lamps in some applications and won't install them) Market potential establishes a

maximum target for the EE savings that an administrator can hope to achieve through its EE programs and involves incentives that represent a substantial portion of the incremental cost combined with high administrative and marketing costs.

- **Achievable potential** reflects expected program participation given significant barriers to customer acceptance, non-ideal implementation conditions, and limited program budgets.

Abbreviations and Acronyms

Throughout the report we use several abbreviations and acronyms. Table 1-1 shows the abbreviation or acronym, along with an explanation.

Table 1-1 Explanation of Abbreviations and Acronyms

Acronym	Explanation
AC	Air conditioning
AEO	Annual Energy Outlook
B/C Ratio	Benefit to Cost Ratio
BEST	EnerNOC's Building Energy Simulation Tool
C&I	Commercial and Industrial
CFL	Compact Fluorescent Lamp
DEEM	Database of Energy Efficiency Measures
DEER	Database for Energy-Efficient Resources
DSM	Demand side management
DR	Demand Response
EE	Energy Efficiency
EIA	Energy Information Administration
EPRI	Electric Power Research Institute
EUI	Energy-use Index
HH	Household
HID	High Intensity Discharge lighting
HPWH	Heat Pump Water Heater
IC	Industry Canada
LED	Light Emitting Diode lamp
LoadMAP	EnerNOC's Load Management Analysis and Planning™ tool
MAR	Market Acceptance Rate
NRCAN	Natural Resources Canada
NWPCC	Northwest Power and Conservation Council
PIF	Program Implementation Factors
RTU	Roof top unit
Sq. ft.	Square feet
STATCAN	Statistics Canada
TRC	Total Resource Cost
UEC	Unit Energy Consumption

CHAPTER | 2

ANALYSIS APPROACH AND DATA DEVELOPMENT

This section describes the analysis approach taken for the study and the data sources used to develop the potential estimates.

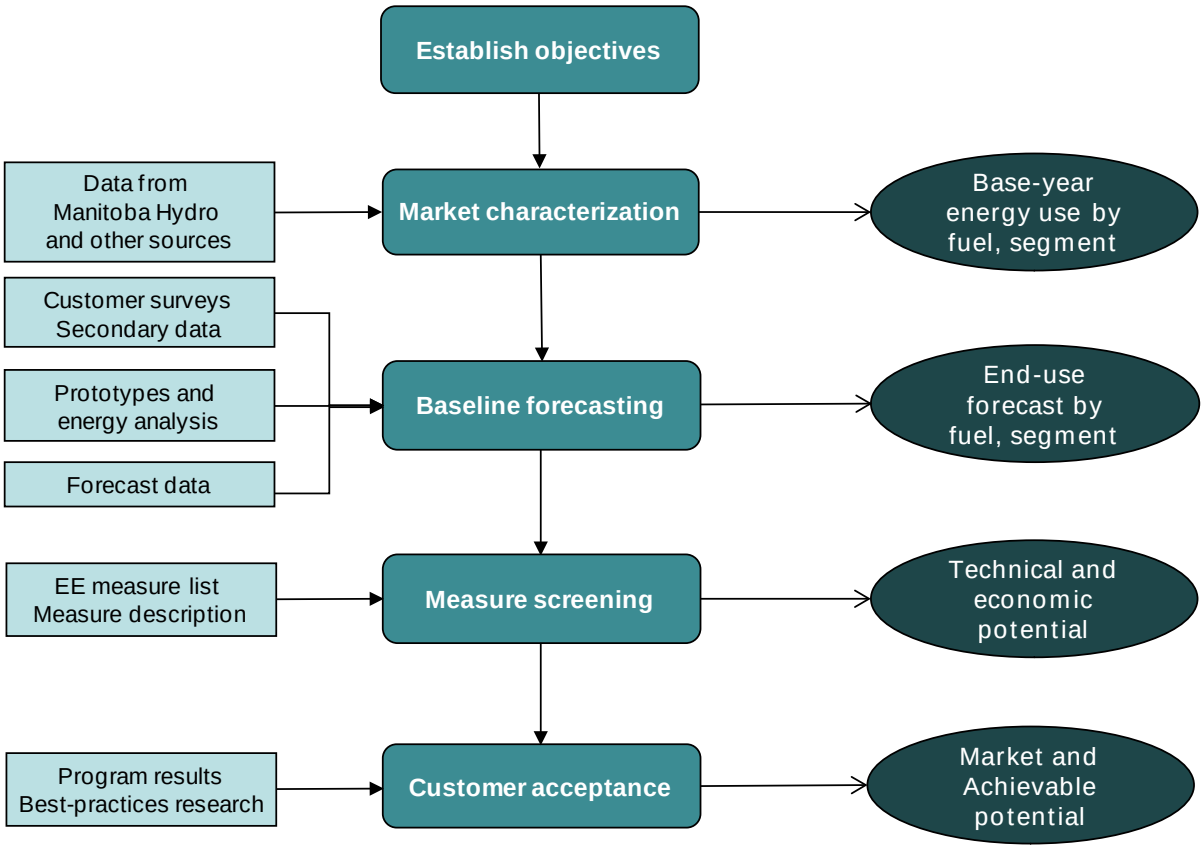
Analysis Approach

To perform the energy efficiency analysis, EnerNOC used a bottom-up analysis approach as shown in Figure 2-1. We took the following steps.

1. Held a meeting with the project team to refine the objectives that were identified in the Manitoba Hydro RFP. This resulted in a work plan for the study.
2. Performed a market characterization to describe sector-level electricity and gas use for the residential, commercial, and industrial sectors for the base year, Manitoba Hydro 2010 (Representing Fiscal year April 2010 through March 2011). This included using utility data and secondary data from sources such as Natural Resources Canada (NRCAN), Industry Canada (IC) and the Energy Information Administration (EIA).
3. Utilized Manitoba Hydro primary market research (such as Manitoba Hydro's 2009 residential customer survey) and secondary sources to understand how customers in the Manitoba Hydro service territory currently use electricity and gas. Combining this information with the market characterization, we developed energy market profiles that describe energy use by sector, segment, and end use for 2010.
4. Developed a baseline electricity and gas forecast by sector, segment, and end use for 2010/11 through 2031/32. Results presented in this volume are through 2031.
5. Identified and analyzed energy-efficiency measures appropriate for the Manitoba Hydro market.
6. Estimated four levels of energy-efficiency potential, *Technical, Economic, Market* and *Achievable*.

These steps are described in further detail throughout the remainder of this chapter.

Figure 2-1 Overview of Analysis Approach



LoadMAP Model

We used EnerNOC's Load Management Analysis and Planning tool (LoadMAP™) version 3.0 to develop both the baseline forecast and the estimates of energy efficiency potential. EnerNOC developed LoadMAP version 1.0 in 2007 and has enhanced it over time, using it for the EPRI National Potential Study and numerous utility-specific forecasting and potential studies. Built in Excel, the LoadMAP framework (see Figure 2-2) is both accessible and transparent and has the following key features.

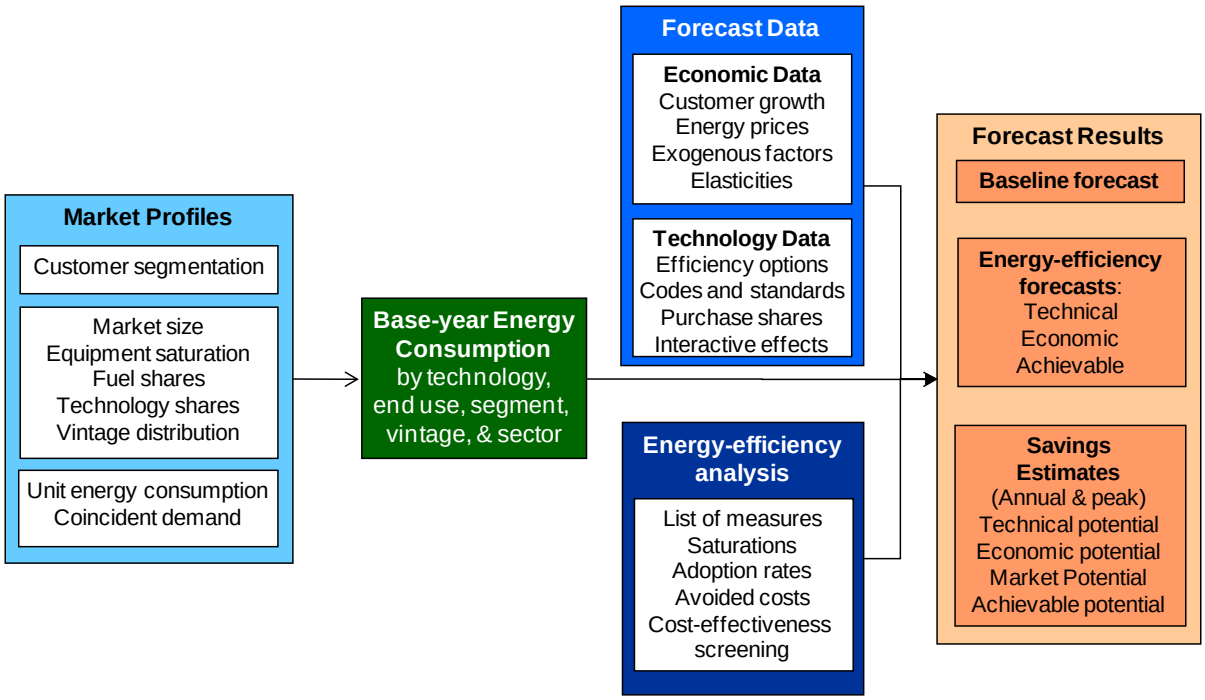
- Embodies the basic principles of rigorous end-use models (such as EPRI's REEPS and COMMEND) but in a more simplified, accessible form.
- Includes stock-accounting algorithms that treat older, less efficient appliance/equipment stock separately from newer, more efficient equipment. Equipment is replaced according to the measure life defined by the user.
- Balances the competing needs of simplicity and robustness by incorporating important modeling details related to equipment saturations, efficiencies, vintage, and the like, where market data are available, and treats end uses separately to account for varying importance and availability of data resources.
- Isolates new construction from existing equipment and buildings and treats purchase decisions for new construction and existing buildings separately.
- Uses a simple logic for appliance and equipment decisions. Other models available for this purpose embody complex decision choice algorithms or diffusion assumptions, and the model parameters tend to be difficult to estimate or observe and sometimes produce anomalous results that require calibration or even overriding. The LoadMAP approach allows the user to

drive the appliance and equipment choices year by year directly in the model. This flexible approach allows users to import the results from diffusion models or to input individual assumptions. The framework also facilitates sensitivity analysis.

- Includes appliance and equipment models customized by end use. For example, the logic for lighting equipment is distinct from refrigerators and freezers.
- Can accommodate various levels of segmentation. Analysis can be performed at the sector level (e.g., total residential) or for customized segments within sectors (e.g., housing type or income level).

Consistent with the segmentation scheme and the market profiles we describe below, the LoadMAP model provides forecasts of baseline energy use by sector, segment, end use, and technology for existing and new buildings. It also provides forecasts of total energy use and energy-efficiency savings associated with the four types of potential.[1]

Figure 2-2 LoadMAP Analysis Framework



Market Characterization

In order to estimate the savings potential from energy-efficient measures, it is necessary to understand how much energy is used today and what equipment is currently being used. The purpose of the market characterization is to develop market profiles that describe current electricity and gas use in terms of sector, customer segment, and end use. The base year for this study is Program Year 2010/11 since that was the most recent year for which a complete set of utility data were available at the start of the analysis.

[1] The model computes energy and peak-demand forecasts for each type of potential for each end use as an intermediate calculation. Annual-energy and peak-demand savings are calculated as the difference between the value in the baseline forecast and the value in the potential forecast (e.g., the technical potential forecast).

Segmentation for Modeling Purposes

The market assessment began by defining the market segments (building types, end uses, and other dimensions) that are relevant for Manitoba Hydro. The analysis segmentation used for this project is presented in Table 2-1.

Table 2-1 Overview of Analysis Segmentation for Potentials Modeling

Segmentation Variable	Market Dimension	Dimension Examples
Sector	Dimension 1	Residential, commercial, industrial
Building type	Dimension 2	Residential (Single family, Multi family, and Apartments, further segmented by heating fuel, geographical location, building vintage and income level.) Commercial (Office, Restaurant, Retail, etc.) Industrial (Mining, Food and Beverage, Pulp and Paper, Chemical, Petroleum, Primary Metals, Miscellaneous Industrial, Other Agriculture, and Other industrial)
Vintage	Dimension 3	Existing and new construction
End uses	Dimension 4	Cooling, space heating, lighting, water heat, motors, etc. (as appropriate by sector)
Fuel	Dimension 5	Electric and Natural Gas
Appliances/end uses and technologies	Dimension 6	Technologies such as lamp type, air conditioning and heating equipment, motors by size, etc.
Equipment efficiency levels for new purchases	Dimension 7	Baseline and higher-efficiency options as appropriate for each technology

Following this scheme, the residential sector was segmented into twenty-nine residential segments as shown in Table 2-2 below. The twenty-nine segments are determined by the following:

- **Home type** — Single-family homes, multifamily homes, or apartments
- **Heating fuel** — Natural gas heat, electric heat, or other fuel
- **Geographic location** — Natural gas available, South-no gas available, North-no gas available, reserve-no gas available, or all
- **Building vintage** — homes built before 2000, 2000 to present, or all
- **Income level** — Non-low income, low income, or all income levels

Table 2-2 Residential Market Segmentation by Housing Type, Base Year FY 2010/11

Segment Name	Home Type	Heating Fuel	Geographic location	Building Vintage	Income Level
SF Gas Pre-2000	Single Family	Gas Heat	Gas Available	Pre-2000	Non-Low Income
SF Gas 2000+	Single Family	Gas Heat	Gas Available	2000-present	Non-Low Income
SF Gas Pre-2000 LI	Single Family	Gas Heat	Gas Available	Pre-2000	Low Income
SF Gas 2000+ LI	Single Family	Gas Heat	Gas Available	2000-present	Low Income
SF Elec GA Pre-2000	Single Family	Electric Heat	Gas Available	Pre-2000	Non-Low Income
SF Elec GA 2000+	Single Family	Electric Heat	Gas Available	2000-present	Non-Low Income
SF Elec GA Pre-2000 LI	Single Family	Electric Heat	Gas Available	Pre-2000	Low Income
SF Elec GA 2000+ LI	Single Family	Electric Heat	Gas Available	2000-present	Low Income
SF Elec SNG Pre-2000	Single Family	Electric Heat	South No Gas	Pre-2000	Non-Low Income
SF Elec SNG 2000+	Single Family	Electric Heat	South No Gas	2000-present	Non-Low Income
SF Elec SNG Pre-2000 LI	Single Family	Electric Heat	South No Gas	Pre-2000	Low Income
SF Elec SNG 2000+ LI	Single Family	Electric Heat	South No Gas	2000-present	Low Income
SF Elec NNG Pre-2000	Single Family	Electric Heat	North No Gas	Pre-2000	Non-Low Income
SF Elec NNG 2000+	Single Family	Electric Heat	North No Gas	2000-present	Non-Low Income
SF Elec NNG Pre-2000 LI	Single Family	Electric Heat	North No Gas	Pre-2000	Low Income
SF Elec NNG 2000+ LI	Single Family	Electric Heat	North No Gas	2000-present	Low Income
SF Elec NG Reserve	Single Family	Electric Heat	Reserve No Gas	All	All
SF Oth All	Single Family	Other	All	All	All
MF Gas	Multi-Family	Gas Heat	All	All	Non-Low Income
MF Gas LI	Multi-Family	Gas Heat	All	All	Low Income
MF Elec	Multi-Family	Electric Heat	All	All	Non-Low Income
MF Elec LI	Multi-Family	Electric Heat	All	All	Low Income
MF Elec NG Reserve	Multi-Family	Electric Heat	Reserve No Gas	All	All
MF Oth All	Multi-Family	Other	All	All	All
Apt Gas	Apartment	Gas Heat	All	All	Non-Low Income
Apt Gas LI	Apartment	Gas Heat	All	All	Low Income
Apt Elec	Apartment	Electric Heat	All	All	Non-Low Income
Apt Elec LI+	Apartment	Electric Heat	All	All	Low Income
Apt Oth All	Apartment	Other	All	All	All

In addition to segmentation by housing type, we identified the set of end uses and technologies that are appropriate for Manitoba Hydro. These are shown in Table 2-3 for the electric technologies and Table 2-4 for the natural gas technologies.

Table 2-3 Residential Electric End Uses and Technologies

End Use	Technology
Cooling	Central Air Conditioning (CAC)
Cooling	Room Air Conditioning (RAC)
Cooling	Evaporative Central Air Conditioning
Space Heating	Electric Resistance
Space Heating	Electric Furnace
Space Heating	Electric Boiler
Space Heating	Supplemental Heat
Combined Heating/Cooling	Geothermal Heat Pump
HVAC Other	Central Exhaust
HVAC Other	Electronic Air Cleaner
HVAC Other	Humidifier
HVAC Other	Dehumidifier
Water Heating	Water Heater
Water Heating	Water Heater - Tankless
Interior Lighting	Screw-in Lamps
Interior Lighting	Linear Fluorescent Lamps
Exterior Lighting	Screw-in Lamps
Appliances	Clothes Washer
Appliances	Clothes Dryer
Appliances	Dishwasher
Appliances	Refrigerator
Appliances	Freezer
Appliances	Second Refrigerator
Appliances	Second Freezer
Appliances	Stove
Appliances	Microwave
Electronics	Personal Computer
Electronics	Monitor
Electronics	Laptop
Electronics	TV
Electronics	Printer/Fax/Copier
Electronics	Set-top Boxes/DVR
Miscellaneous	Pool Pump
Miscellaneous	Pool Heater
Miscellaneous	Hot Tub / Spa
Miscellaneous	Well Pump
Miscellaneous	Furnace Fan
Miscellaneous	Sewage Pump
Miscellaneous	Sump Pump
Miscellaneous	Pressure Pump
Miscellaneous	Sauna
Miscellaneous	Car Block Heater
Miscellaneous	Car Warmer
Miscellaneous	Electric Vehicle
Miscellaneous	Miscellaneous

Table 2-4 Residential Gas End Uses and Technologies

End Use	Technology
Space Heating	Gas Furnace
Space Heating	Gas Boiler
Space Heating	Supplemental Heat
Water Heating	Water Heater
Appliances	Clothes Dryer
Appliances	Stove
Miscellaneous	Pool Heater
Miscellaneous	Gas Barbeque
Miscellaneous	Miscellaneous

For the commercial sector, it is useful to analyze the segments based on the unique characteristics of the building type. For this study, we used the following 19 building types:

- **Large Office** — all types of large offices including large government facilities
- **Small Office** — all types of small offices
- **Restaurant** — fast-food, sit-down and cafeteria-style restaurants
- **Large Retail** — retail establishments such as large box retailers and malls
- **Small Retail** — retail establishments such as small boutiques and mini-malls
- **Grocery** — supermarkets, convenience stores and small markets
- **Large Warehouse** — large storage facilities, including climate-controlled cold storage and unrefrigerated buildings
- **Small Warehouse** — small storage facilities, including climate-controlled cold storage and unrefrigerated buildings
- **Large Education** — colleges and technical schools
- **Small Education** — primary and secondary schools
- **Large Health** — hospitals and large medical office buildings
- **Small Health** — small medical/dental offices and nursing homes
- **Lodging** — motels, hotels, resorts and small inns
- **Bulk Apartments** — master-metered apartments
- **Services** — all types of buildings related to the service industry such as automotive, dry cleaning, salons, etc.
- **Large Recreation Facility** — large recreation facilities such as stadiums and amusement parks
- **Small Recreation Facility** — small recreation facilities such as fitness facilities and miniature golf courses
- **Large Miscellaneous** — all remaining large building types, such as convention centers, museums, etc.
- **Small Miscellaneous** — all remaining small building types, such as police stations, parking garages, etc.

In addition to segmentation by building type, we identified the set of end uses and technologies that are appropriate for Manitoba Hydro. Table 2-5 lists the electric end uses and technologies used in this study. Table 2-6 lists the natural gas end uses and technologies.

Table 2-5 Commercial Electric End Uses and Technologies

End Use	Technology
Cooling	Air-Cooled Chiller
Cooling	Water-Cooled Chiller
Cooling	Roof Top AC
Cooling	Other Cooling
Space Heating	Electric Heating
Combined Heating/Cooling	Roof Top Heat Pump
Ventilation	Ventilation
Water Heating	Water Heating
Interior Lighting	Screw-in
Interior Lighting	High-Bay Fixtures
Interior Lighting	Linear Fluorescent
Exterior Lighting	Screw-in
Exterior Lighting	HID
Exterior Lighting	Linear Fluorescent
Refrigeration	Walk-in Refrigerator
Refrigeration	Reach-in Refrigerator
Refrigeration	Glass Door Display
Refrigeration	Open Display Case
Refrigeration	Icemaker
Refrigeration	Vending Machine
Food Preparation	Oven
Food Preparation	Fryer
Food Preparation	Dishwasher
Food Preparation	Hot Food Container
Office Equipment	Desktop Computer
Office Equipment	Laptop
Office Equipment	Server
Office Equipment	Monitor
Office Equipment	Printer/Copier/Fax
Office Equipment	POS Terminal
Miscellaneous	Non-HVAC Motors
Miscellaneous	Pool Pump
Miscellaneous	Pool Heater
Miscellaneous	Miscellaneous

Table 2-6 Commercial Natural Gas End Uses and Technologies

End Use	Technology
Space Heating	Furnace
Space Heating	Boiler
Space Heating	Other Heating
Water Heating	Water Heating
Food Preparation	Oven
Food Preparation	Fryer
Food Preparation	Broiler
Food Preparation	Griddle
Food Preparation	Range
Food Preparation	Steamer
Miscellaneous	Pool Heater
Miscellaneous	Miscellaneous

The industrial sector is segmented by major industry type. We used the forecast of Top Consumers to help guide the industries to isolate. The segmentation is as follows:

- Mining
- Food and Beverage
- Pulp and Paper
- Chemical
- Petroleum
- Primary Metals
- Miscellaneous Industrial
- Other Agriculture
- Other Industrial

In addition to segmentation by industry, we identified the set of end uses and technologies that are appropriate for Manitoba Hydro. These are shown for the electric and natural gas technologies in Table 2-7 and Table 2-8, respectively.

Table 2-7 Industrial Electric End Uses and Technologies

End Use	Technology
Cooling	Air-Cooled Chiller
Cooling	Water-Cooled Chiller
Cooling	Roof Top AC
Cooling	Other Cooling
Space Heating	Electric Heating
Ventilation	Ventilation
Water Heating	Water Heating
Interior Lighting	Screw-in
Interior Lighting	High-Bay Fixtures
Interior Lighting	Linear Fluorescent
Exterior Lighting	Screw-in
Exterior Lighting	HID
Exterior Lighting	Linear Fluorescent
Pumps	Pumps
Fans and Blowers	Fans and Blowers
Compressed Air	Compressed Air
Conveyors	Conveyors
Other Motors	Other Motors
Process Heating	Process Heating
Process Cooling and Refrigeration	Process Cooling and Refrigeration
Electro-Chemical	Electro-Chemical
Other Process	Other Process
Miscellaneous	Miscellaneous

Table 2-8 Industrial Gas End Uses and Technologies

End Use	Technology
Space Heating	Furnace
Space Heating	Boiler
Space Heating	Other Heating
Process Heating	Process Heating
Process Cooling	Process Cooling
Other Process	Other Process
Miscellaneous	Miscellaneous

With the segmentation scheme defined, we then performed a high-level market characterization of electricity and natural gas sales in the base year to allocate sales to each customer segment. We used various Manitoba Hydro data sources to identify the annual sales in each customer segment, as well as the market size for each segment. This information provided sector level control totals (energy use and customers counts/square footage/employee totals) for calibrating the LoadMAP model to known data for the base-year.

Market Profiles

The next step was to develop market profiles for each sector, customer segment, end use, and technology. A market profile includes the following elements:

- **Market size** is a representation of the number of customers in the segment. For the residential sector, it is number of households. In the commercial sector, it is floor space measured in square feet. For the industrial sector, we use energy use as the definition of market size. (However, in the LoadMAP model we unitize industrial use on a per-employee basis.)
- **Saturations** define the fraction of homes and square feet with the electric or natural gas technologies. (e.g., homes with electric or natural gas space heating, commercial floor space with space cooling). The saturation values are based on Manitoba Hydro's 2009 residential customer survey, 2005 and 1993 Commercial surveys, Manitoba Hydro's internal natural gas potential study, EnerNOC's Energy Market Profiles[2], Natural Resources Canada's Commercial and Institutional Building Energy Use Survey (CIBEUS), and other potential studies including the previous DSM potential study for Manitoba Hydro.
- **UEC (unit energy consumption) or EUI (energy-use index)** describes the amount of electricity or natural gas consumed in 2010/11 by a specific technology in buildings that have the technology. For the residential sector, we started with the UECs available from Manitoba Hydro's conditional demand model, where available. To fill in holes, we used our databases from previous studies, the previous energy efficiency potential study, the Annual Energy Outlook (AEO), and EnerNOC's BEST simulation tool to develop these values. For the commercial and industrial sectors, we developed the technology-level EUIs using our engineering model, BEST, EnerNOC's Energy Market Profiles database, and other secondary sources. Finally, we adjusted the UECs or EUIs to calibrate to overall building type intensity.

  For electricity, we use UECs expressed in kWh/household for the residential sector, and EUIs expressed in kWh/square foot for the commercial sector. For natural gas, the UECs are expressed in m^3/unit.
- **Intensity** for the residential sector represents the average energy use for the technology across all homes in 2010. It is computed as the product of the saturation and the UEC and is defined as kWh/household for electricity or m^3/household for natural gas. For the commercial sector, intensity, computed as the product of the saturation and the EUI, represents the average use for the technology across all floor space in 2010/11.
- **Usage** is the annual electricity or natural gas use by a technology/end use in the segment. It is the product of the market size and intensity and is quantified in GWh for electricity or MMm^3 for gas.

The market assessment results and the market profiles are presented in Chapter 3.

Baseline Forecast

The next step was to develop the baseline forecast of annual electricity and natural gas usage and peak demand for 2010/11 through 2031/32 by customer segment and end use without new utility programs or naturally occurring efficiency scenario. The end-use forecast does include the relatively certain impacts of codes and standards that will unfold over the study timeframe. All such mandates that were defined as of January 2011 are included in the baseline. The baseline forecast is the foundation for the analysis of savings from future EE efforts as well as the metric against which potential savings are measured.

Inputs to the baseline forecast include:

[2] The Energy Market Profiles provide commercial sector energy-use data, by end use and fuel, for 15 building types, based on U.S. DOE's Energy Information Agency's Commercial Building Energy Consumption Survey (CBECS) as well as other secondary data sources. For this analysis, we used Energy Market Profile data for the West North Central region, which includes Minnesota and North Dakota.

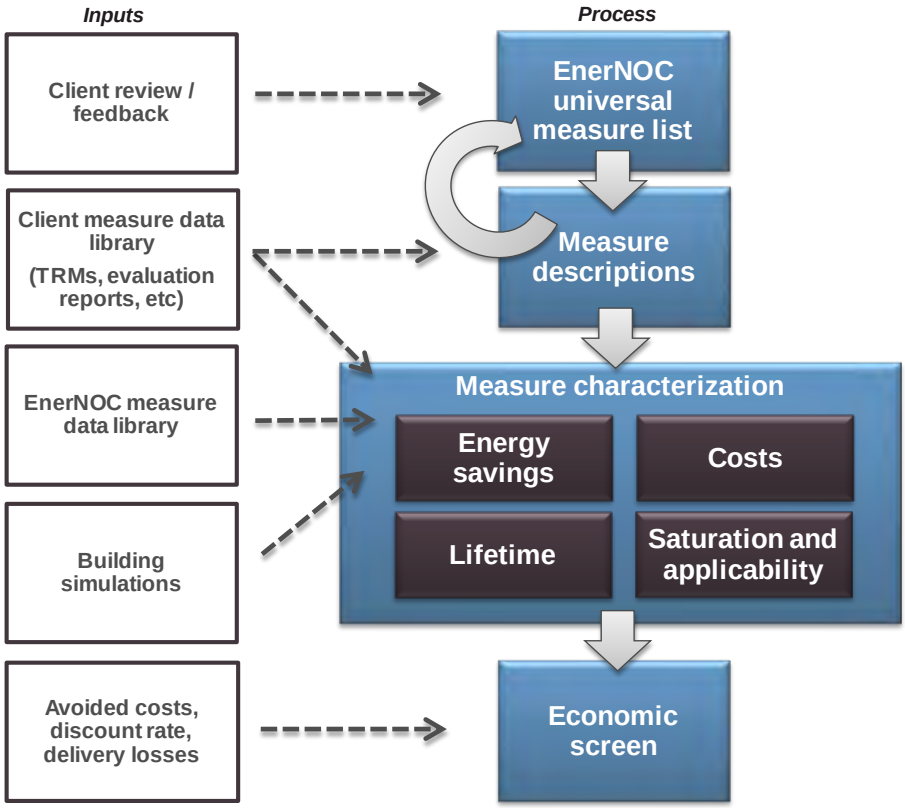
- Current economic growth forecasts (i.e., customer growth, income growth)
- Electricity and natural gas price forecasts
- Trends in fuel shares and equipment saturations
- Existing and approved changes to building codes and equipment standards
- Equipment purchase decisions
- Heating and cooling degree days
- Manitoba Hydro's internally developed forecasts for electricity and natural gas sales

We present the results of the baseline forecast development in Chapter 4.

Energy Efficiency Measure Analysis

This section describes the framework used to assess the savings, costs, and other attributes of energy-efficiency measures. These characteristics form the basis for measure-level cost-effectiveness analyses as well as for determining measure-level savings. For all measures, EnerNOC assembled information to reflect equipment performance, incremental costs, and equipment lifetimes. We used this information, along with Manitoba Hydro's avoided costs data, in the economic screen to determine economically feasible measures. Figure 2-3 outlines the framework for measure analysis.

Figure 2-3 Approach for Measure Assessment



The framework for assessing savings, costs, and other attributes of energy efficiency measures involves identifying the list of energy efficiency measures to include in the analysis, determining their applicability to each market sector and segment, fully characterizing each measure, and performing cost-effectiveness screening. Potential measures include the replacement of a unit that has failed or is at the end of its useful life with an efficient unit, retrofit/early replacement of equipment, improvements to the building envelope, the application of controls to optimize energy use, and other actions resulting in improved energy efficiency.

We compiled a robust list of energy efficiency measures for each customer sector, drawing upon a variety of sources including Manitoba Hydro's measure database, EnerNOC databases, and secondary sources. This universal list of EE measures covers all major types of end-use equipment, as well as devices and actions to reduce energy consumption. If considered today, some of these measures would not pass the economic screens initially, but may pass in future years as a result of lower projected equipment costs or higher avoided costs in the future.

The selected measures are categorized into two types: equipment measures and non-equipment measures, according to the LoadMAP taxonomy:

- **Equipment measures,** or efficient energy-consuming pieces of equipment, save energy by providing the same service with a lower energy requirement than a standard unit. An example is an ENERGY STAR refrigerator that replaces a standard efficiency refrigerator. For equipment measures, many efficiency levels are available for a specific technology ranging from the baseline unit (often determined by code or standard) up to the most efficient product commercially available. For instance, in the case of residential natural gas water heater, this list begins with the federal standard EF 0.57 unit and spans a broad spectrum of efficiency, with the highest efficiency level represented by a EF 0.86 unit.
- **Non-equipment measures** save energy by reducing the need for delivered energy but do not involve replacement or purchase of major end-use equipment (such as a refrigerator or air conditioner). An example would be an insulation upgrade that reduces the heating requirements of the heating system due to reduced thermal losses. Non-equipment measures fall into one of the following categories:
    - Building shell (windows, insulation, roofing material)
    - Equipment controls (thermostat, occupancy sensors)
    - Equipment maintenance (cleaning filters, changing setpoints)
    - Whole-building design (natural ventilation, passive solar lighting)
    - Lighting retrofits (included as a non-equipment measure because retrofits are performed prior to the equipment's normal end of life)
    - Displacement measures (ceiling fan to reduce use of central air conditioners)
    - Commissioning and retrocommissioning

We developed a preliminary list of EE measures for Manitoba Hydro's review. The final list included in the study is presented in Chapter 5. Note that non-equipment measures can apply to more than one end use. For example, insulation levels will affect the energy use of both cooling and space heating.

Once we assembled the list of EE measures, the project team assessed their energy-saving characteristics. For each measure we characterized incremental cost, service life, and other performance factors. Following the measure characterization, we performed an economic screening of each measure, which serves as the basis for developing the economic potential.

Representative Measure Data Inputs

To provide an example of the measure data, Table 2-9 and Table 2-10 present samples of the detailed data inputs behind both equipment and non-equipment measures, respectively, for the case of residential natural gas furnaces in single-family homes with natural gas space heating built before 2000. Table 2-9 displays the various efficiency levels available as equipment measures, as well as the corresponding useful life, energy usage, and cost estimates. The columns labeled On Market and Off Market reflect equipment availability due to codes and standards or the entry of new products to the market. The on-market of 2010 indicates that the technology is currently commercially available. In Canada there is no natural gas furnace standard in effect, like it is in the United States. If a standard were in place that required a minimum AFUE 96% in 2015, the off market for AFUE 92% would be 2014.

Table 2-9 Sample Equipment Measures for Natural Gas Furnaces – Single Family Home

Efficiency Level	Useful Life	Equipment Cost	Energy Usage(m3/yr)	On Market	Off Market
AFUE 92%	15	$6,516	1,894	2010	n/a
AFUE 96%	15	$6,800	1,788	2010	n/a

Table 2-10 lists some of the non-equipment measures affecting natural gas furnaces in an existing single-family home. All measures are evaluated for cost effectiveness based on the lifetime benefits relative to the cost of the measure. The total savings are calculated for each year of the model and depend on the base year saturation of the measure, the applicability[3] of the measure, and the savings as a percentage of the relevant energy end uses.

Table 2-10 Sample Non-Equipment Measures – Single Family Home, Existing

End Use	Measure	Saturation in 2010[4]	Applica-bility	Lifetime (yrs)	Measure Installed Cost	Energy Savings (%)
Heating	Furnace – Gas, Maintenance	32%	100%	4	$122	4.6%
Heating	Insulation, Ducting	15%	100%	25	$341	3.3%
Heating	Ducting, Repair and Sealing	12%	100%	20	$365	13.6%
Heating	Insulation, Infiltration Control	24%	100%	12	$259	6.8%
Heating	Insulation, Ceiling	36%	90%	30	$993	31.6%
Heating	Insulation, Wall Cavity	50%	100%	30	$998	20.8%
Heating	Insulation, Attic Hatch	15%	50%	18	$69	1.4%
Heating	Doors, Storm and Thermal	38%	100%	12	$311	1.4%
Heating	Windows, ENERGY STAR	61%	100%	25	$7,298	24.7%
Heating	Thermostat, Clock/Programmable	61%	75%	11	$111	6.6%

Screening Measures for Cost-Effectiveness

Only measures that are cost-effective are included in economic and achievable potential. Therefore, for each individual measure, LoadMAP performs an economic screen. This study uses the total resource cost (TRC) test that compares the lifetime benefits (both energy and peak demand) of each applicable measure with its installed cost.

- Cost includes material and labor for the measure
- The lifetime benefits are calculated by multiplying the annual energy and demand savings for each measure by all appropriate avoided costs for each year, and discounting the dollar savings to the present value equivalent. The analysis uses each measure's values for savings,

[3] The applicability factors take into account whether the measure is applicable to a particular building type and whether it is feasible to install the measure. For instance, attic fans are not applicable to homes without attics, and in some homes with attics, it may not be feasible to install an attic fan because of lack of space.
[4] Note that saturation levels reflected for the base year change over time as more measures are adopted.

costs, and lifetimes that were developed as part of the measure characterization process described above. For economic screening of measures, incentives are not included because they represent a simple transfer from one party to another, but have no effect on the overall measure cost.

The LoadMAP model performs this screening dynamically, taking into account changing savings and cost data over time. Thus, some measures pass the economic screen for some — but not all — of the years in the forecast.

It is important to note the following about the economic screen:

- The economic evaluation of every measure in the screen is conducted relative to a baseline condition. For instance, in order to determine the kilowatt-hour (kWh) savings potential of a measure, kWh consumption with the measure applied must be compared to the kWh consumption of a baseline condition.
- The economic screening was conducted only for measures that are applicable to each building type and vintage; thus if a measure is deemed to be irrelevant to a particular building type and vintage, it is excluded from the respective economic screen.

Table 2-11 shows the results of the economic screen for a natural gas furnace for selected years, as well as results for two interior lighting technologies. In 2012/13, the most cost-effective option is AFUE 92%. The table also shows how the economic choice for two of the lighting technology options varies over the study period. For the interior screw-in lighting CFLs are the cost effective technology until 2020/21, when LED lamps become cost effective. If the measure passes the screen (has a benefit-to-cost (B/C) ratio greater than or equal to 1.0), the measure is included in economic potential. Otherwise, it is screened out for that year. If multiple equipment measures have B/C ratios greater than or equal to 1.0, the most efficient technology is selected by the economic screen.

Table 2-11 Economic Screen Results for Selected Residential Equipment Measures

Technology	2012/13	2017/18	2022/23	2027/28	2031/32
Natural Gas Furnace	AFUE 92%	AFUE 92%	AFUE 92%	AFUE 92%	AFUE 92%
Interior Lighting Screw-in	CFL	CFL	LED	LED	LED
Interior Lighting Linear Fluorescent	T5	T5	T5	T5	T5

Energy-Efficiency Potential

The approach we used for this study adheres to the approaches and conventions outlined in the National Action Plan for Energy-Efficiency (NAPEE) Guide for Conducting Potential Studies (November 2007).[5] The NAPEE Guide represents the most credible and comprehensive industry practice for specifying energy-efficiency potential. As described in Chapter 1, four types of potentials were developed as part of this effort: Technical potential, Economic potential, Market potential and Achievable potential.

The calculation of Technical and Economic potential is a straightforward algorithm. To develop estimates for **Market potential**, we develop market adoption rates for each measure that specify the percentage of customers that will select the highest–efficiency economic option. The Market potential adoption rates are based on the MAP ramp rates from the Northwest Power & Conservation Council's Sixth Plan as a starting point. The NWPCC has been running programs in the Pacific Northwest for many years, and the portfolio of programs reflects a similar profile of

[5] National Action Plan for Energy Efficiency (2007). *National Action Plan for Energy Efficiency Vision for 2025: Developing a Framework for Change*. www.epa.gov/eeactionplan.

market maturity. For a handful of measures specific to Manitoba Hydro, the ramp rates were adjusted to better represent the service area.

The **Achievable potential** adoption rates start with the market potential adoption rates and adjust them to reflect recent program experience at Manitoba Hydro and results from other utilities as captured in EnerNOC potential studies from similarly-situated utilities.

The overall energy efficiency potential results are available in Chapter 6, and the results by sector are given in Chapter 7.

Data Development

This section details the data sources used in this study, followed by a discussion of how these sources were applied.

Data Sources

The data sources are organized into the following categories:

- Utility-provided data
- EnerNOC' databases and analysis tools
- Energy efficiency measure data
- Other secondary data and reports

Utility-provided Data

In order to appropriately characterize the market in Manitoba Hydro, we asked Manitoba Hydro to provide the following:

- Utility 2010/11 billing data — customers, usage, revenue
- Number of customers and electricity sales by sector and segment (residential, commercial, industrial)
- Coincident peak demand by rate class
- Energy and peak demand forecasts, at the sector level
- Number of customers and natural gas sales by sector and segment (residential, commercial, industrial)
- Customer growth forecast
- Price history and forecast
- Income and household size forecasts
- Cooling and heating degree day history and forecasts
- Recent saturation surveys for residential and commercial customers
- Avoided costs (peak capacity and energy)
- Discount rate
- Escalation rate
- T&D line loss factors
- Program data
    - Description of existing energy efficiency programs
    - Description of existing demand-response programs
- Recent energy efficiency potential studies

EnerNOC Databases, Analysis Tools, and Reports

EnerNOC maintains several databases and modeling tools that we use for forecasting and potential studies.

- **Energy Market Profiles Database.** For more than 10 years, EnerNOC staff have maintained profiles of end-use consumption for the residential, commercial, and industrial sectors. These profiles include market size, fuel shares, unit consumption estimates, and annual energy use by fuel (electricity and natural gas), customer segment and end use for 10 regions in the U.S. The Energy Information Administration surveys (RECS, CBECS and MECS) as well as state-level statistics and local customer research provide the foundation for these regional profiles.
- **Building Energy Simulation Tool (BEST)**. EnerNOC's BEST is a derivative of the DOE 2.2 building simulation model, used to estimate base-year UECs and EUIs, as well as measure savings for the HVAC-related measures.
- **Database of Energy Efficiency Measures (DEEM)**. EnerNOC maintains a database of energy efficiency measures for residential, commercial, and industrial segments across the U.S. This is analogous to the DEER database developed for California. EnerNOC updates the database on a regular basis as it conducts new energy efficiency potential studies. The updates draws upon reliable sources including the California Database for Energy Efficient Resources (DEER), the EIA Technology Forecast Updates – Residential and Commercial Building Technologies – Reference Case, RS Means cost data, and Grainger Catalog Cost data.
- **EnergyShapeTM Database**. database of load shapes includes the following: Residential – electric load shapes for 10 regions, 3 housing types, 13 end uses; Commercial – electric load shapes for 9 regions, 54 building types, 10 end uses; Industrial – electric load shapes, whole facility only, 19 2-digit SIC codes, as well as various 3-digit and 4-digit SIC codes.
- **Recent Studies**. EnerNOC has conducted numerous studies of EE potential in the last five years. We checked our input assumptions and analysis results against the results from these other studies, which include AmerenUE, Los Angeles Department of Water and Power, Consolidated Edison of New York, Avista Utilities, the State of New Mexico, Seattle City Light, and Tennessee Valley Authority. In addition, we used the information about impacts of building codes and appliance standards from a recent report for the Institute for Energy Efficiency.

Other Secondary Data and Reports

Finally, a variety of secondary data sources and reports were used for this study. The main sources are identified below.

- **Natural Resources Canada's Commercial and Institutional Building Energy Use Survey (CIBEUS)**. This survey was conducted by Statistics Canada in 2001. It provides energy intensities, energy consumption data, and energy efficiency characteristics for commercial and institutional buildings.
- **California Statewide Surveys**. California has conducted among the most comprehensive surveys of residential and commercial customers in the world. The Residential Appliance Saturation Survey (RASS) and the Commercial End Use Survey (CEUS) are comprehensive market research studies conducted by the California Energy Commission. These databases provide a wealth of information on appliance use in homes and businesses. RASS is based on information from almost 25,000 homes and CEUS is based on information from a stratified random sample of almost 3,000 businesses in California.
- **Annual Energy Outlook**. The Annual Energy Outlook (AEO), conducted each year by the U.S. Energy Information Administration (EIA), presents yearly projections and analysis of energy topics. For this study, we used data from the 2011 AEO.

- **Electric Power Research Institute – Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.**, also known as the EPRI National Potential Study (2009). In 2009, EPRI hired EnerNOC to conduct an assessment of the national potential for energy efficiency, with estimates derived for the four DOE regions.
- **EPRI End-Use Models (REEPS and COMMEND).** These models provide the elasticities we apply to electricity prices, household income, home size and heating and cooling.
- **Northwest Power and Conservation Council Sixth Plan workbooks.** To develop its Power Plan, the Council maintains workbooks with detailed information about measures.

Data Application

We now discuss how the data sources described above were used for each step of the study.

Data Application for Market Characterization

To construct the high-level market characterization of electricity and natural gas use by households/floor space for the residential, commercial, and industrial sectors, we applied data from Manitoba Hydro, the Annual Energy Outlook, and EnerNOC's Energy Market Profiles Database:

- Historical customer billing data by sector (e.g., residential, commercial, and industrial)
- Manitoba Hydro's 2009 Residential Customer Survey and other utility-provided data to allocate residential customers by housing type
- Manitoba Hydro-provided data and Energy Market Profiles Database to allocate sales and square footage by building type for the commercial sector
- Manitoba Hydro-provided data on energy use by industry type, Energy Market Profiles Database and AEO data to allocate sales and employment for the industrial sector

Data Application for Market Profiles

To develop the market profiles for each segment, we used the following general approach:

1. Used Manitoba Hydro's control totals for each segment. These include market size, segment-level annual electricity use, natural gas use and annual intensity.
2. Used Manitoba Hydro-provided saturation survey data and Energy Market Profiles Database to incorporate information on existing appliance and equipment saturations, appliance and equipment characteristics, and building characteristics.
3. Incorporated secondary data sources to supplement and corroborate the data from items 1 and 2 above.
4. Compared and cross-checked with regional data obtained as part of the EPRI National Potential Study and with the Energy Market Profiles Database, as well as previous energy efficiency potential studies.
5. Ensured calibration to control totals for annual electricity and natural gas sales in each sector and segment.
6. Worked with Manitoba Hydro staff to vet the data against their knowledge and experience.

The specific data elements for the market profiles, together with the key data sources, are shown in Table 2-12.

Table 2-12 Data Applied for the Market Profiles

Model Inputs	Description	Key Sources
Market size	Base-year residential dwellings commercial floor space, and industrial employment	Utility billing data Utility data Energy Market Profiles NRCAN STATCAN IC AEO
Annual intensity	Residential: Annual energy use (kWh/household) Commercial: Annual energy use (kWh/sq ft) Industrial: Annual energy use (kWh/employee)	Utility data Energy Market Profiles CIBEUS AEO Previous DSM potential studies
Appliance/equipment saturations	Fraction of dwellings with an appliance/technology Percentage of C&I floor space/employment with equipment/technology	Residential Customer Survey Commercial Survey Gas Potential Study Energy Market Profiles CIBEUS Previous DSM potential studies
UEC/EUI for each end-use technology	UEC: Annual electricity use for a technology in dwellings that have the technology EUI: Annual electricity use per square foot/employee for a technology in floor space that has the technology	Manitoba Hydro's conditional demand model Other: Engineering analysis Energy Market Profiles AEO Previous DSM potential studies
Appliance/equipment vintage distribution	Age distribution for each technology	Utility saturation surveys Previous DSM potential studies
Efficiency options for each technology	List of available efficiency options and annual energy use for each technology	Manitoba Hydro measure database DEEM DEER NWPCC workbooks Annual Energy Outlook Previous DSM potential studies
Peak factors	Share of technology energy use that occurs during the peak hour	Utility data EnergyShape database

Data Application for Baseline Forecast

Table 2-13 summarizes the LoadMAP model inputs required for the baseline forecast. These inputs are required for each segment within each sector, as well as for new construction and existing dwellings/buildings.

Table 2-13 Data Needs for the Baseline Forecast and Potentials Estimation in LoadMAP

Model Inputs	Description	Key Sources
Customer growth forecasts	Forecasts of new construction in residential and C&I sectors	Manitoba Hydro customer growth forecast AEO 2011 growth forecast Industry Canada
Equipment purchase shares for baseline forecast	For each equipment/technology, purchase shares for each efficiency level; specified separately for existing equipment replacement and new construction	Shipments data from AEO AEO 2011 forecast assumptions[6] Appliance/efficiency standards analysis
Electricity and gas prices	Forecast of average electricity and gas prices	Manitoba Hydro price forecasts
Utilization model parameters	Price elasticities, elasticities for other variables (income, weather)	EPRI's REEPS and COMMEND models Manitoba Hydro forecasting data Environment Canada AEO 2011

In addition, we implemented assumptions for known future equipment standards as of January, 2011, as shown in Table 2-14 through Table 2-17.

Table 2-14 Residential Electric Equipment Standards

Today's Efficiency or Standard Assumption | 1st Standard (relative to today's standard) | 2nd Standard (relative to today's standard)

End Use	Technology	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cooling	Central AC	SEER 13														
	Room AC	EER 9.8														
	Evaporative Central AC	Conventional														
	Evaporative Room AC	Conventional														
Cooling/Heating	Geothermal Heat Pump	EER 13.2														
Space Heating	Electric Resistance	Electric Resistance														
Water Heating	Water Heater	EF 0.90														
Lighting	Screw-in/Pin Lamps	Incandescent			Infrared Halogen - tier 1 (20 lumens/watt)						Infrared Halogen - tier 2 (45 lumens/watt)					
	Linear Fluorescent	T12		T8												
Appliances	Refrigerator/2nd Refrigerator	NAECA Standard														
	Freezer	NAECA Standard														
	Dishwasher	Conventional														
	Clothes Washer	Conventional														
	Clothes Dryer	Conventional														

[6] We developed baseline purchase decisions using the Energy Information Agency's *Annual Energy Outlook* report (2011), which utilizes the National Energy Modeling System (NEMS) to produce a self-consistent supply and demand economic model. We calibrated equipment purchase options to match manufacturer shipment data for recent years and then held values constant for the study period. This removes any effects of naturally occurring conservation or effects of future DSM programs that may be embedded in the AEO forecasts.

Table 2-15 Residential Natural Gas Equipment Standards

Today's Efficiency or Standard Assumption
Next Standard (relative to today's standard)

End Use	Technology	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heating	Furnace	AFUE .92														
	Boiler	EF 0.80		EF 0.82												
Water Heating	Water Heater	EF 0.57														
Appliances	Clothes Dryer	Conventional														
	Range/Oven	Conventional														
Miscellaneous	Pool Heater	Conventional														

Table 2-16 Commercial Electric Equipment Standards

Today's Efficiency or Standard Assumption
1st Standard (relative to today's standard)
2nd Standard (relative to today's standard)

End Use	Technology	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Cooling	Chillers	2007 ASHRAE 90.1														
	Roof Top Units	EER 11.0/11.2														
	Other Cooling	EER 10.6														
Cooling/Heating	Heat Pump	EER 11.0/COP 3.3														
Ventilation	Ventilation	Constant Air Volume/Variable Air Volume														
Lighting	Screw-in/Pin Lamps	Incandescent				90W Halogen PAR-38						70W HIR PAR-38				
	Linear Fluorescent	T12														
	High Intensity Discharge	Metal Halide														
Water Heating	Water Heater	EF 0.97														
Refrigeration	Walk-in Refrigerator/Freezer	EISA 2007 Standard														
	Reach-in Refrigerator	EPACT 2005 Standard														
	Glass Door Display	EPACT 2005 Standard														
	Open Display Case	EPACT 2005 Standard														
	Vending Machines	EPACT 2005 Standard														
	Icemaker	2010 Standard														
Miscellaneous	Non-HVAC Motors	62.3% Efficiency				70% Efficiency										

Table 2-17 Commercial Gas Equipment Standards

Today's Efficiency or Standard Assumption
Next Standard (relative to today's standard)
2nd Standard (relative to today's standard)

End Use	Technology	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Space Heating	Furnace	EF 0.90														
	Boiler	EF 0.76	EF 0.80			EF 0.85										
Water Heating	Water Heater	Conventional	EF 0.80						EF 0.94							
Miscellaneous	Pool Heater	Conventional														

Energy Efficiency Measure Data Application

Table 2-18 details the data sources used for measure characterization.

Table 2-18 Data Needs for the Measure Characteristics in LoadMAP

Model Inputs	Description	Key Sources
Energy Impacts	The annual reduction in consumption attributable to each specific measure. Savings were developed as a percentage of the energy end use that the measure affects.	Manitoba Hydro Measure Database BEST EPRI National Study DEEM DEER Other secondary sources
Peak Demand Impacts	Savings during the peak demand periods are specified for each measure. These impacts relate to the energy savings and depend on the extent to which each measure is coincident with the system peak.	Manitoba Hydro Measure Database BEST EnergyShape
Costs	Equipment Measures: Includes the full cost of purchasing and installing the equipment on a per-unit, per-square-foot, or per employee basis for the residential, commercial, and industrial sectors, respectively. Non-equipment measures: Existing buildings – full installed cost. New Construction - the costs may be either the full cost of the measure, or as appropriate, it may be the incremental cost of upgrading from a standard level to a higher efficiency level.	Manitoba Hydro Measure Database DEEM DEER Other secondary sources
Measure Lifetimes	Estimates derived from the technical data and secondary data sources that support the measure demand and energy savings analysis.	Manitoba Hydro Measure Database DEEM DEER Other secondary sources
Applicability	Estimate of the percentage of either dwellings in the residential sector or square feet/employment in the C&I sectors where the measure is applicable and where it is technically feasible to implement.	DEEM DEER Other secondary sources
On Market and Off Market Availability	Expressed as years for equipment measures to reflect when the equipment technology is available or no longer available in the market.	Natural Resources Canada, Office of Energy Efficiency Appliance, building codes, and standards analysis

Data Application for Cost-effectiveness Screening

To perform the cost-effectiveness screening, a number of economic assumptions were needed. All cost and benefit values were escalated for inflation at an annualized forecast GDP growth rate of 1.86%. Discount rates, line loss factors, avoided capacity, and avoided energy costs were provided by Manitoba Hydro.

Achievable Potential Estimation

To estimate potentials, three sets of parameters were required to account for the decision making behavior of customers in the efficiency marketplace.

- **Adoption rates for non-equipment measures**. Equipment measures are installed when existing units fail. Non-equipment measures do not have this natural periodicity, so rather than installing all available non-equipment measures in the first year of the forecast (instantaneous potential), they are phased in according to adoption schedules that vary based on cost and complexity. The adoption rates used in this analysis take several factors into account to determine how quickly the market can absorb these measures. Typically, measures that cause disruption to the building, such as wall insulation in existing buildings, receive longer adoption curves, while those with drop-in installations, such as programmable thermostats in new buildings, receive shorter ones. High capital cost measures will also receive longer adoption curves than ones with low capital cost. These adoption rates are used within LoadMAP to generate the technical and economic potentials. In general, the rates align with the diffusion of similar equipment measures.
- **Adoption rates for Market potential (MARs).** These factors are applied to economic potential to estimate the upper bound: market potential. These estimate customer adoption of economic measures when delivered through efficiency programs under ideal market, implementation, regulatory, and customer preference conditions. Information channels are assumed to be established and efficient for marketing, educating consumers, and coordinating with trade allies and delivery partners. The only barrier is customer preferences for the technology or measure.

  The Market potential adoption rates are based on the ramp rates from the Northwest Power & Conservation Council's Sixth Plan adjusted to reflect Manitoba Hydro's service territory, as a starting point. The NWPCC has been running programs in the Pacific Northwest for many years, and the portfolio of programs reflects a similar profile of market maturity. Market potential establishes a maximum target for the EE savings that an administrator can hope to achieve through its EE programs and involves incentives that represent a substantial portion of the incremental cost combined with high administrative and marketing costs.
- **Adoption rates for Achievable potential (PIFs).** These factors are applied to Market potential to calculate Achievable potential, decrementing them by a range of 40% to 90% based on where measures lie in the time horizon of the study or whether they are already familiar inclusions in existing programs. These rates reflect expected program participation given significant barriers to customer acceptance, non-ideal implementation conditions, and limited program budgets. This represents a lower bound on achievable potential

MARs and PIFs are presented in Appendix E.

CHAPTER | 3

MARKET CHARACTERIZATION AND MARKET PROFILES

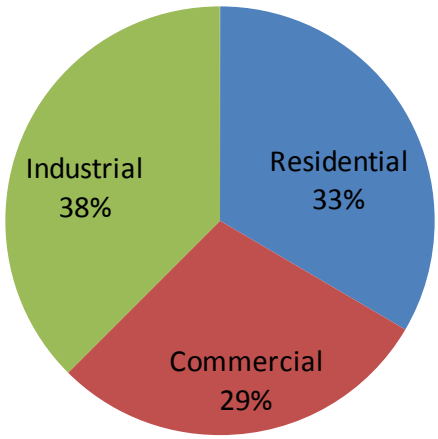
In this section, we describe how customers in Manitoba use electricity and natural gas in the base year of the study, 2010/11. It begins with a high-level summary of energy use by sector and then delves into each sector in detail.

Energy Use Summary

Manitoba Hydro is one of the largest electric and natural gas distribution utilities in Canada. It serves approximately 537,000 electric customers throughout Manitoba and 265,000 natural gas customers in Southern Manitoba. The utility had a total net income of $150 million for the 2010-11 fiscal year.[7] The top industries in the service territory are chemical products, primary metals, petroleum, and food products.

Total electricity use for the residential, commercial and industrial sectors for Manitoba Hydro in 2010/11 was 20,213 GWh.[8] As shown in Figure 3-1, the largest sector is industrial, accounting for 38%, or 7,576 GWh. The remaining use is split between the residential and commercial and sectors, at 6,952 GWh and 5,685 GWh respectively.

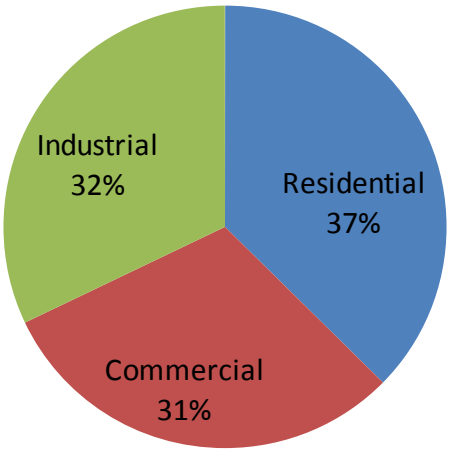
Figure 3-1 Sector-Level Electricity Use, 2010/11



Total gas use for the residential, commercial and industrial sectors in 2010 was 1,585 MMm^3. As shown in Figure 3-2, the largest sector is residential, accounting for 37%, or 590 MMm^3. The remaining use is closely split between the industrial (32%) and commercial (31%) sectors, at 509 MMm^3 and 486 MMm^3 respectively.

[7] http://www.hydro.mb.ca/corporate/ar/2010/publish/index.html#/12/
[8] Energy given "at-the-meter," i.e. does not include line losses.

Figure 3-2 Sector-Level Gas Use, 2010/11



Residential Sector

This section characterizes the residential market at a high level, and then provides a profile of how customers in each segment use electricity and gas by end use. The customer information for electricity will be presented first, followed by the gas information.

Electricity Use

Total residential electricity use in 2010/11 was 6,952 GWh. Customer information for each segment are shown in Table 3-1, Figure 3-3, and Figure 3-4.The single-family segment as a whole used the vast majority (89%) of the total residential sector electricity in 2010/11, also representing the largest number of customers. The largest individual segment was the single family, gas heat, pre-2000, non-low income segment which comprised approximately 26% of the total usage. This segment also has the largest number of customers (35%).

Table 3-1 Residential Sector Electricity Usage by Segment Type

Segment Name	Home Type	Heating	Geographic location	Vintage	Income	Ave. Elec Custs	Elec Use (GWh)
SFGasPre-2000	SF	GasHeat	GasAvailable	Pre-2000	Non-LowIncome	155,115	1,802
SFGas2000+	SF	GasHeat	GasAvailable	2000-present	Non-LowIncome	15,235	239
SFGasPre-2000LI	SF	GasHeat	GasAvailable	Pre-2000	LowIncome	42,779	359
SFGas2000+LI	SF	GasHeat	GasAvailable	2000-present	LowIncome	566	7
SFElecGAPre-2000	SF	ElectricHeat	GasAvailable	Pre-2000	Non-LowIncome	39,441	1,145
SFElecGA2000+	SF	ElectricHeat	GasAvailable	2000-present	Non-LowIncome	7,312	226
SFElecGAPre-2000LI	SF	ElectricHeat	GasAvailable	Pre-2000	LowIncome	10,279	253
SFElecGA2000+LI	SF	ElectricHeat	GasAvailable	2000-present	LowIncome	1,329	32
SFElecSNGPre-2000	SF	ElectricHeat	SouthNoGas	Pre-2000	Non-LowIncome	32,608	966
SFElecSNG2000+	SF	ElectricHeat	SouthNoGas	2000-present	Non-LowIncome	4,293	145
SFElecSNGPre-2000LI	SF	ElectricHeat	SouthNoGas	Pre-2000	LowIncome	9,801	233
SFElecSNG2000+LI	SF	ElectricHeat	SouthNoGas	2000-present	LowIncome	643	13
SFElecNNGPre-2000	SF	ElectricHeat	NorthNoGas	Pre-2000	Non-LowIncome	6,038	171
SFElecNNG2000+	SF	ElectricHeat	NorthNoGas	2000-present	Non-LowIncome	522	15
SFElecNNGPre-2000LI	SF	ElectricHeat	NorthNoGas	Pre-2000	LowIncome	1,099	32
SFElecNNG2000+LI	SF	ElectricHeat	NorthNoGas	2000-present	LowIncome	70	2
SFElecNGReserve	SF	ElectricHeat	ReserveNoGas	All	All	15,136	468
SFOthAll	SF	Other	All	All	All	10,921	184
MFGas	MF	GasHeat	All	All	Non-LowIncome	13,232	124
MFGasLI	MF	GasHeat	All	All	LowIncome	6,806	48
MFElec	MF	ElectricHeat	All	All	Non-LowIncome	5,679	94
MFElecLI	MF	ElectricHeat	All	All	LowIncome	2,418	38
MFElecNGReserve	MF	ElectricHeat	ReserveNoGas	All	All	722	19
MFOthAll	MF	Other	All	All	All	4,901	31
AptGas	Apt	GasHeat	All	All	Non-LowIncome	1,358	8
AptGasLI	Apt	GasHeat	All	All	LowIncome	1,090	5
AptElec	Apt	ElectricHeat	All	All	Non-LowIncome	12,738	129
AptElecLI+	Apt	ElectricHeat	All	All	LowIncome	7,885	57
AptOthAll	Apt	Other	All	All	All	33,604	111
Total						**443,618**	**6,952**

Figure 3-3 Residential Electric Customers by Segment, 2010-2011 (% of customers)

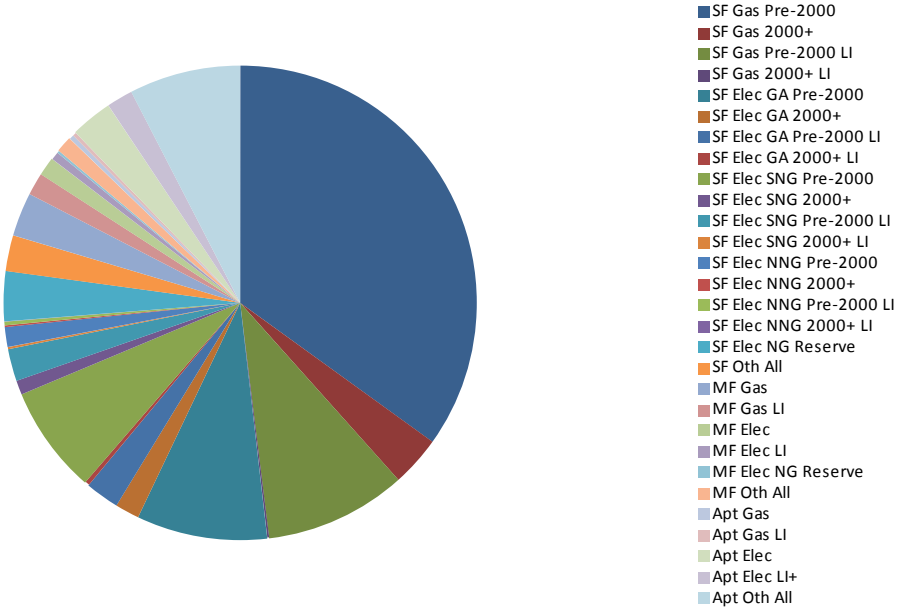
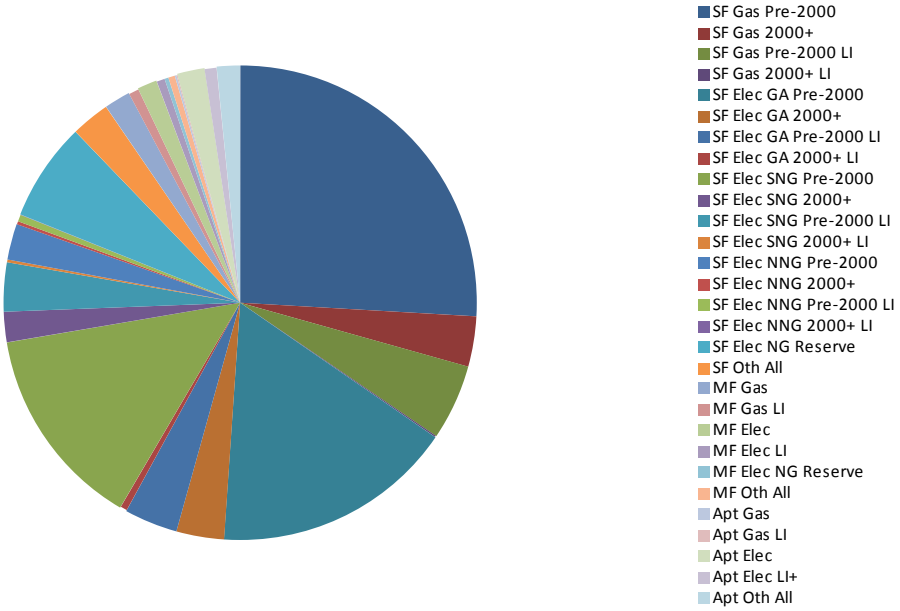


Figure 3-4 Residential Electric Use by Segment, 2010-2011 (% of electricity sales)



As we describe in the previous chapter, the market profiles provide the foundation upon which we develop the baseline forecast. The electric market profile for the residential sector as a whole is presented in Table 3-2. The residential market profiles for each housing segment are presented in Appendix A.

Table 3-2 Electric Market Profile for the Residential Sector

Average Market Profiles

End Use	Technology	Saturation	UEC (kWh)	Intensity (kWh/HH)	Usage (GWh)
Cooling	Central AC	59.6%	922	550	244
Cooling	Room AC	18.6%	391	73	32
Cooling	Geothermal Heat Pump	1.6%	205	3	1
Cooling	Evaporative Central AC	0.0%	307	0	0
Space Heating	Electric Resistance	12.7%	11,502	1,461	648
Space Heating	Electric Furnace	18.9%	14,621	2,760	1,225
Space Heating	Electric Boiler	1.3%	11,462	147	65
Space Heating	Geothermal Heat Pump	1.6%	9,254	151	67
Space Heating	Supplemental Heat	27.3%	621	170	75
HVAC Other	Central Exhaust	10.3%	344	35	16
HVAC Other	Electronic Air Cleaner	9.8%	1,080	105	47
HVAC Other	Humidifier	18.2%	519	94	42
HVAC Other	Dehumidifier	29.5%	502	148	66
Water Heating	Water Heater	45.2%	3,341	1,510	670
Water Heating	Water Heater - Tankless	0.2%	2,517	4	2
Interior Lighting	Screw-in	100.0%	887	887	394
Interior Lighting	Linear Fluorescent	66.9%	101	68	30
Exterior Lighting	Screw-in	100.0%	206	206	91
Appliances	Clothes Washer	86.7%	391	339	150
Appliances	Clothes Dryer	82.9%	838	695	308
Appliances	Dishwasher	65.7%	305	200	89
Appliances	Refrigerator	99.8%	802	800	355
Appliances	Freezer	78.4%	672	527	234
Appliances	Second Refrigerator	43.2%	1,226	529	235
Appliances	Second Freezer	17.8%	824	147	65
Appliances	Stove	95.0%	613	582	258
Appliances	Microwave	95.5%	92	88	39
Electronics	Personal Computers	77.0%	302	233	103
Electronics	Monitor	77.0%	56	43	19
Electronics	Laptops	43.2%	85	37	16
Electronics	TVs	190.8%	194	371	165
Electronics	Printer/Fax/Copier	84.0%	41	35	15
Electronics	Set-top Boxes/DVR	134.7%	323	435	193
Miscellaneous	Pool Pump	3.2%	2,779	88	39
Miscellaneous	Pool Heater	0.6%	11,208	70	31
Miscellaneous	Hot Tub / Spa	10.2%	1,931	197	87
Miscellaneous	Well Pump	12.4%	551	69	30
Miscellaneous	Furnace Fan	75.1%	1,225	920	408
Miscellaneous	Sewage Pump	9.8%	39	4	2
Miscellaneous	Sump Pump	14.1%	48	7	3
Miscellaneous	Pressure Pump	10.2%	776	79	35
Miscellaneous	Sauna	1.7%	2,456	41	18
Miscellaneous	Car Block Heaters	71.7%	135	97	43
Miscellaneous	Car Warmers	6.7%	237	16	7
Miscellaneous	Electric Vehicles	0.0%	1,707	0	0
Miscellaneous	Miscellaneous	100.0%	650	650	289
	Total			**15,671**	**6,952**

Figure 3-5 presents the electric end-use breakout for the residential sector as a whole. Space conditioning—including heating, cooling and HVAC other — accounts for over a third of total energy use. Appliances and miscellaneous are the next largest uses, with 25% and 14% of total energy use, respectively. Water heating, lighting, and electronics (personal computers, televisions, video game consoles, etc.), make up the remaining use. Note that the miscellaneous end use includes furnace fans, pool pumps, well pumps, car block heaters, and other "plug" loads (hair dryers, power tools, coffee makers, toaster ovens, etc.).

Figure 3-5 Residential Electricity Use by End Use, 2010/11

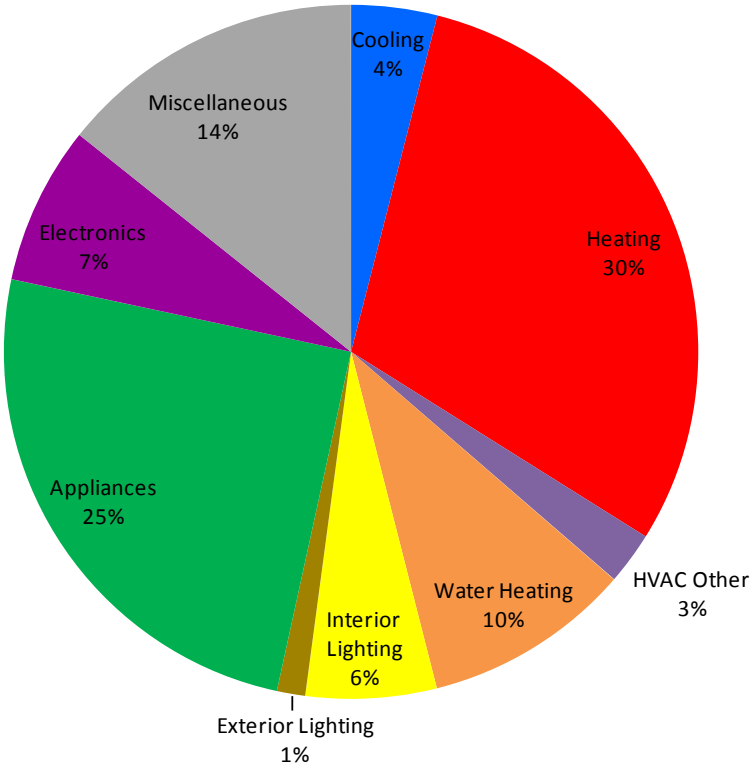
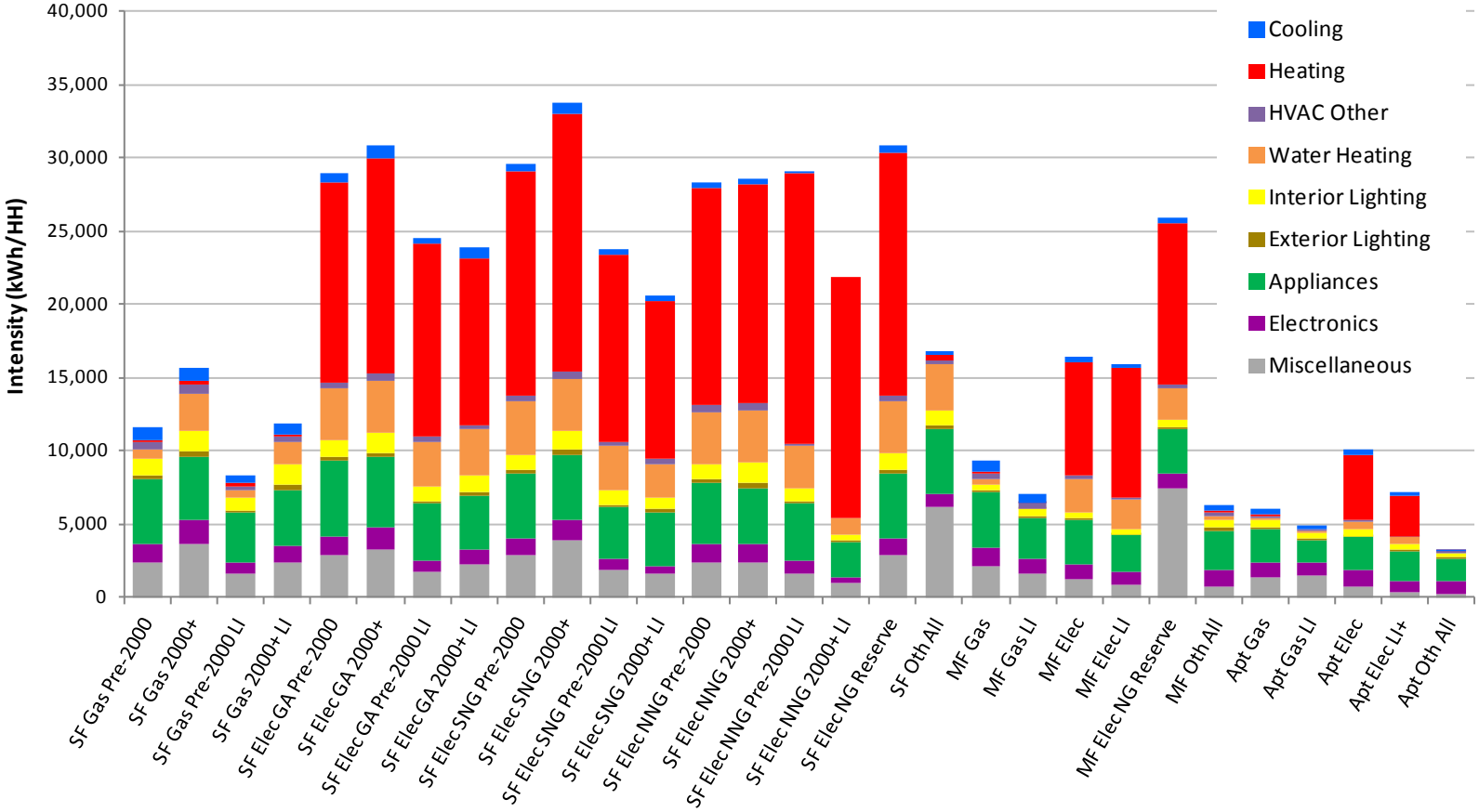


Figure 3-6 presents the end-use shares of residential electricity use for each housing type. Most end uses other than space conditioning have a fairly constant share across segments.

Figure 3-6 End-Use Shares of Total Electricity Use by Housing Type, 2010/11



Natural Gas Use

Total residential gas use in 2010/11 was 590 MMm^3. Information for each customer segment is shown in Table 3-3,

Figure 3-7, and Figure 3-8. Similar to electricity, the single-family segment as a whole used the vast majority (over 90%) of the total residential sector natural gas in 2010-2011 as a result of the largest number of customers.

Table 3-3 Residential Sector Gas Usage by Segment Type

Segment Name	Home Type	Heating	Geographic location	Vintage	Income	# Natural Gas Customers	Natural Gas Use (MMm^3)
SFGasPre-2000	SF	Gas Heat	Gas Available	Pre-2000	Non-Low Income	155,115	402.6
SFGas2000+	SF	Gas Heat	Gas Available	2000-present	Non-Low Income	15,235	330
SFGasPre-2000LI	SF	Gas Heat	Gas Available	Pre-2000	Low Income	42,779	104.2
SFGas2000+LI	**SF**	Gas Heat	Gas Available	2000-present	Low Income	566	1.6
SFElecGAPre-2000	SF	Electric Heat	Gas Available	Pre-2000	Non-Low Income	39,441	3.5
SFElecGA2000+	SF	Electric Heat	Gas Available	2000-present	Non-Low Income	7,312	0.4
SFElecGAPre-2000LI	SF	Electric Heat	Gas Available	Pre-2000	Low Income	10,279	1.0
SFOthAll	SF	Other	All	All	All	10,921	1.2
MFGas	MF	Gas Heat	All	All	Non-Low Income	13,232	26.0
MFGasLI	MF	Gas Heat	All	All	Low Income	6,806	14.3
MFElec	MF	Electric Heat	All	All	Non-Low Income	5,679	0.0
MFOthAll	MF	Other	All	All	All	4,901	0.8
AptGas	Apt	Gas Heat	All	All	Non-Low Income	1,358	1.0
AptGasLI	Apt	Gas Heat	All	All	Low Income	1,090	0.6
Total						**314,713**	**590.1**

Figure 3-7 Residential Natural Gas Customers by Segment, 2010/11 (% of customers)

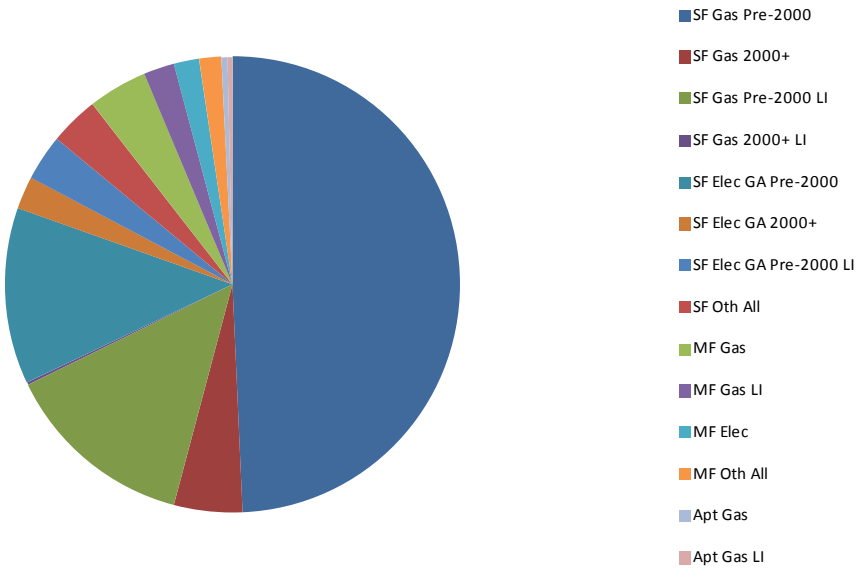
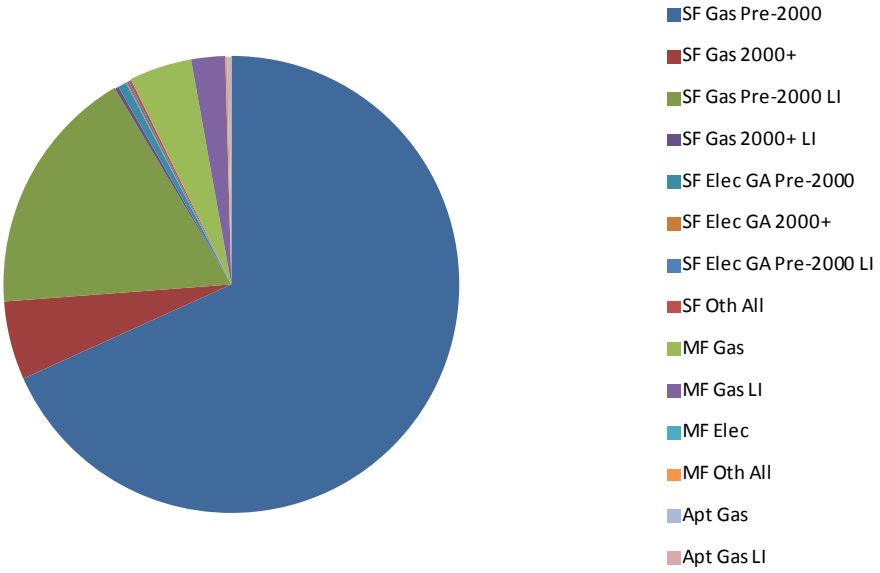


Figure 3-8 Residential Natural Gas Use by Segment, 2010/11 (% of gas sales)



The natural gas market profile for the residential sector as a whole is presented in Table 3-4. The residential market profiles for each housing segment are presented in Appendix A.

Table 3-4 Natural Gas Market Profile for the Residential Sector

Average Market Profiles

End Use	Technology	Saturation	UEC (m3)	Intensity (m3/HH)	Usage (MMm3)
Space Heating	Gas Furnace	72.0%	1,896	1,365	429.6
Space Heating	Gas Boiler	3.0%	3,618	109	34.4
Space Heating	Supplemental Heat	8.1%	390	32	9.9
Water Heating	Water Heater	59.2%	502	297	93.5
Appliances	Clothes Dryer	5.3%	178	9	2.9
Appliances	Stove	4.8%	274	13	4.1
Miscellaneous	Pool Heater	2.4%	1,539	37	11.7
Miscellaneous	Gas Barbeque	2.9%	127	4	1.2
Miscellaneous	Miscellaneous	87.5%	10	9	2.7
Total				**1,875**	**590.1**

Figure 3-9 presents the natural gas end-use breakout for the residential sector as a whole. The space heating end use accounts for over three-quarters of total natural gas use. Water heating is the next largest use with 16% of total natural gas use. Appliances and miscellaneous (pool heaters, gas barbeque grills, farming equipment, etc.) make up the remaining use totaling to just under 5%.

Figure 3-9 Residential Natural Gas Use by End Use, 2010/11

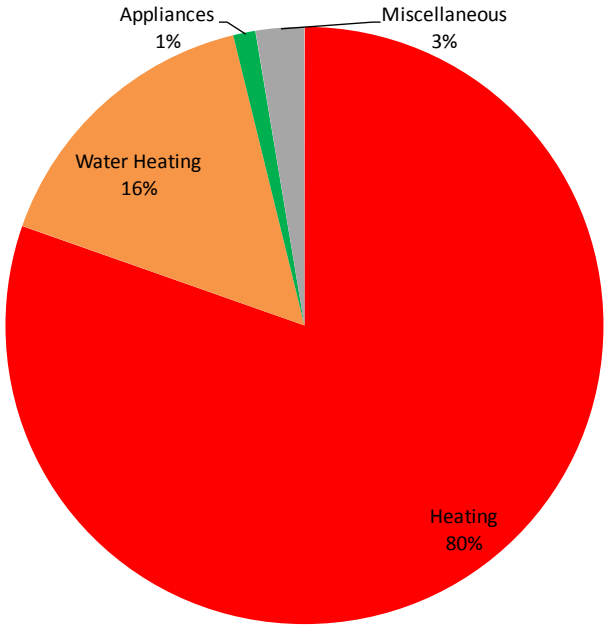
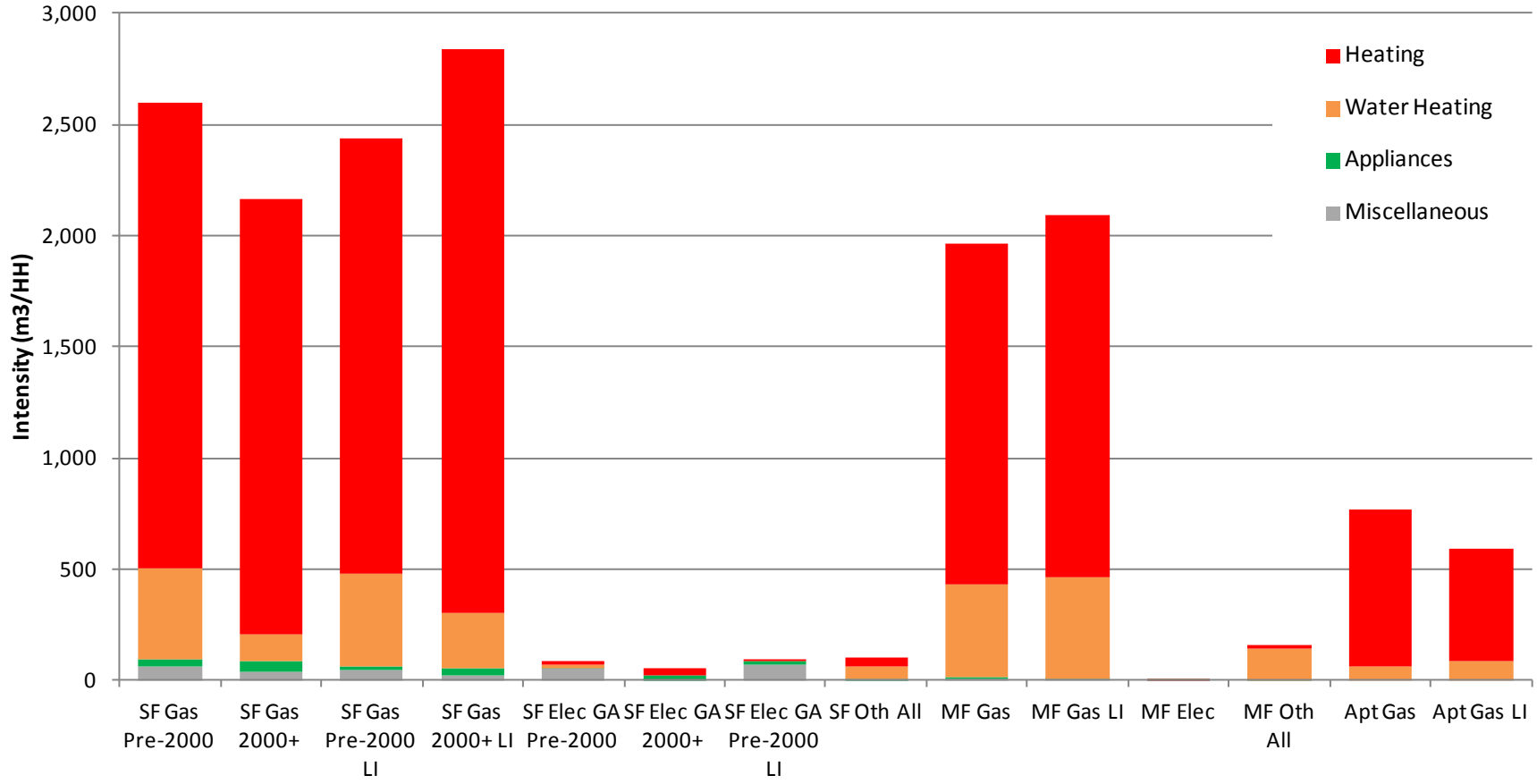


Figure 3-10 presents the end-use shares of residential natural gas use for each housing type.

Figure 3-10 End-Use Shares of Total Natural Gas Use by Housing Type, 2010/11



Commercial Sector

This section characterizes the commercial market at the segment level, and then provides a profile of how each segment uses electricity and natural gas by end use.

Electricity Use

Total electricity use in the commercial sector in 2010/11 was 5,685 GWh. Manitoba Hydro provided estimates of floor space for each of the segments. Floor space is used to normalize energy use and develop intensity in terms of GWh per square foot of floor space. Total commercial floor space is estimated at 388 million square feet, implying an average intensity of 14.6 kWh per square foot per year.

Table 3-5 presents the floor space, intensity estimates, and annual electricity use for each building type. The largest segments by energy usage are large office, large retail, and bulk apartments. The largest segments by floor space are bulk apartments and services. Groceries and restaurants have the highest intensity due to the large amount of refrigeration and cooking. Small warehouses, small education and services have the lowest intensities.

Table 3-5 Commercial Sector Electric Market Characterization Results, 2010/11

Segment	Floor Space (MSqFt)	Intensity (GWh/sq ft)	Sales (GWh)
Large Office	31.9	18.9	603.4
Small Office	25.3	14.7	372.8
Restaurant	7.7	40.9	315.8
Large Retail	21.9	27.2	595.2
Small Retail	30.1	11.5	344.6
Grocery	7.7	41.4	319.2
Large Warehouse	15.7	17.9	280.7
Small Warehouse	23.6	6.9	162.9
Large Education	19.6	10.4	203.0
Small Education	17.3	8.4	144.8
Large Health	13.6	21.5	290.9
Small Health	3.4	12.2	41.4
Lodging	18.5	17.1	315.2
Bulk apartments	41.3	13.1	541.2
Services	37.1	8.1	301.1
Large Recreation Facility	15.9	17.9	284.6
Small Recreation Facility	17.8	10.1	180.0
Large Miscellaneous	5.4	10.2	54.6
Small Miscellaneous	34.8	9.6	333.6
Total	**388.4**	**14.6**	**5,684.9**

Table 3-6 shows the electric market profile for the commercial sector as a whole, representing a composite of all the building types. Overall, less than 20% of the commercial floorspace is heated through electric technologies, either some form of resistance heating or heat pumps. About 77% of

commercial electric floor space is cooled. Linear fluorescent lighting is the largest single energy-consuming technology in the commercial sector, closely followed by screw-in lamps. Roof top AC, ventilation, high intensity discharge lighting are the next largest uses. Market profiles for each building type are presented in Appendix A.

Table 3-6 Commercial Sector Composite Electric Market Profile, 2010

Average Market Profiles

End Use	Technology	Saturation	EUI (kWh)	Intensity (kWh/Sqft)	Usage (GWh)
Cooling	Air-Cooled Chiller	3.7%	5.93	0.22	85.1
Cooling	Water-Cooled Chiller	12.4%	5.50	0.68	265.1
Cooling	Roof top AC	36.5%	4.04	1.47	572.6
Cooling	Roof top Heat Pump	6.7%	3.76	0.25	98.0
Cooling	Other Cooling	17.9%	2.75	0.49	190.9
Heating	Roof top Heat Pump	6.7%	4.66	0.31	121.4
Heating	Electric Heating	12.0%	5.15	0.62	240.6
Ventilation	Ventilation	100.0%	1.10	1.10	429.0
Water Heating	Water Heating	40.8%	1.59	0.65	252.4
Interior Lighting	Screw-in	64.2%	2.91	1.87	725.2
Interior Lighting	High-Bay Fixtures	38.0%	1.02	0.39	149.7
Interior Lighting	Linear Fluorescent	89.7%	2.47	2.21	859.1
Exterior Lighting	Screw-in	17.5%	0.62	0.11	42.1
Exterior Lighting	HID	61.1%	1.16	0.71	275.3
Exterior Lighting	Linear Fluorescent	29.0%	0.17	0.05	19.2
Refrigeration	Walk-in Refrigerator	25.7%	1.35	0.35	135.4
Refrigeration	Reach-in Refrigerator	10.1%	0.22	0.02	8.6
Refrigeration	Glass Door Display	31.3%	1.50	0.47	181.9
Refrigeration	Open Display Case	6.7%	1.05	0.07	27.3
Refrigeration	Icemaker	19.9%	0.25	0.05	19.5
Refrigeration	Vending Machine	2.8%	0.25	0.01	2.7
Food Preparation	Oven	18.3%	0.30	0.06	21.6
Food Preparation	Fryer	18.3%	0.40	0.07	28.6
Food Preparation	Dishwasher	27.0%	0.49	0.13	51.5
Food Preparation	Hot Food Container	18.3%	0.14	0.03	9.7
Office Equipment	Desktop Computer	84.7%	0.74	0.62	242.1
Office Equipment	Laptop	84.7%	0.11	0.09	35.4
Office Equipment	Server	31.9%	0.40	0.13	49.8
Office Equipment	Monitor	84.7%	0.14	0.12	44.9
Office Equipment	Printer/Copier/Fax	77.0%	0.11	0.08	31.8
Office Equipment	POS Terminal	35.7%	0.08	0.03	11.6
Misc	Non-HVAC Motors	55.1%	1.07	0.59	228.5
Misc	Pool Pump	3.9%	0.04	0.00	0.5
Misc	Pool Heater	1.0%	0.06	0.00	0.2
Misc	Misc	100.0%	0.59	0.59	227.3
Total				**14.64**	**5,684.9**

Figure 3-11 shows the breakdown of annual commercial electricity usage by end use. Space conditioning (cooling, heating and ventilation) and lighting (interior and exterior) are the largest end uses, consuming 35% and 37% of commercial building energy use, respectively.

Figure 3-11 Commercial Electricity Use by End Use, 2010-2011

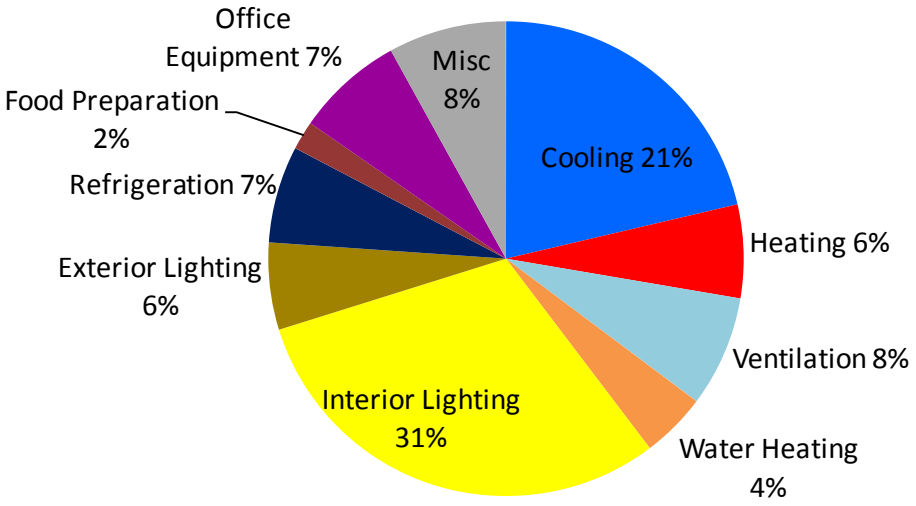
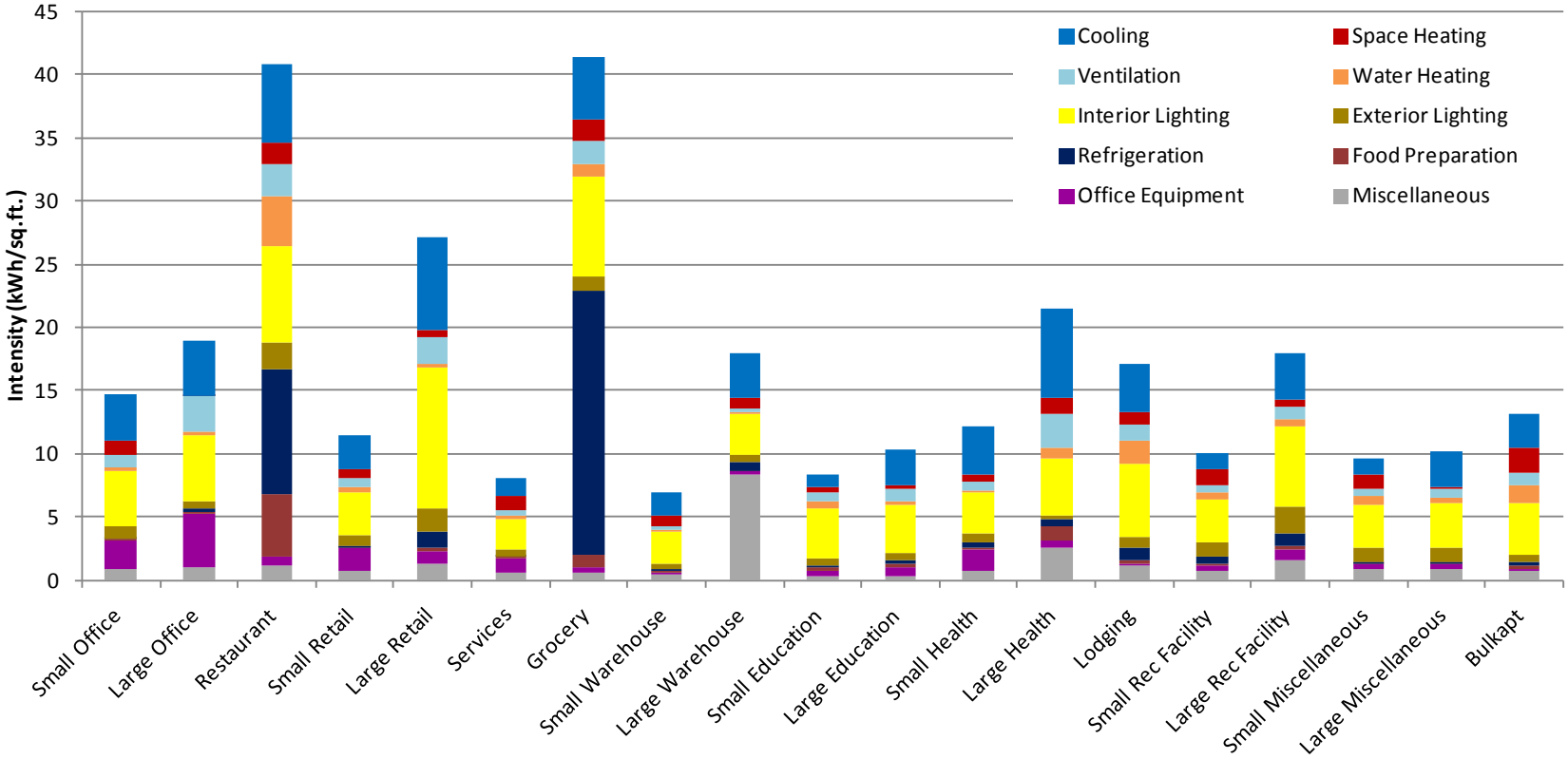


Figure 3-12 illustrates how the end-use composition of electricity use varies by building type. Observations include the following:

- Lighting and cooling are major end uses across all building types
- Refrigeration has a large share in grocery stores and restaurants
- Office equipment has substantial use in large offices, small offices, small retail, and services.
- Miscellaneous is highest in large warehouse and large health since this end use includes grain elevators and medical equipment, respectively.

Figure 3-12 Commercial End Use Electric Intensities by Building Type, 2010/11



Natural Gas Use

Total commercial natural gas use in 2010/11 was 486 MMm^3. Table 3-7 presents the floor space, intensity estimates, and annual gas use for each building type. The three largest segments by intensity are large miscellaneous, restaurant, and large health. The three largest segments by sales are large office, large health, and services.

Table 3-7 Commercial Sector Gas Market Characterization Results, 2010/11

Segment	Floor Space (MSqFt)	Intensity (m^3/sq ft)	Sales (MMm^3)
Large Office	31.9	2.0	64.1
Small Office	20.4	1.2	23.6
Restaurant	6.1	4.4	26.6
Large Retail	21.9	1.5	32.1
Small Retail	22.9	1.2	26.9
Grocery	4.1	1.1	4.7
Large Warehouse	14.8	1.2	17.6
Small Warehouse	20.9	1.0	21.1
Large Education	16.6	1.5	24.6
Small Education	14.5	1.3	19.4
Large Health	12.4	3.2	39.4
Small Health	3.1	2.4	7.7
Lodging	15.8	1.2	18.2
Bulk apartments	31.8	0.8	24.0
Services	29.2	1.3	37.7
Large Recreation Facility	14.8	2.0	29.2
Small Recreation Facility	11.6	0.8	8.8
Large Miscellaneous	5.4	5.6	30.1
Small Miscellaneous	23.9	1.3	30.2
Total	**322.0**	**1.5**	**485.9**

Table 3-8 shows the natural gas market profile for the commercial sector as a whole, representing a composite of all the building types. Overall, about 86% of commercial natural gas floor space is heated. Furnaces are the largest single energy-consuming technology in the commercial sector, followed by boilers, and water heating.

Market profiles for each building type are presented in Appendix A. Note that for modeling purposes in the natural gas analysis, LoadMAP requires total floor space (i.e. electric square footage) instead of gas square footage to normalize energy use. Therefore, the inputs to LoadMAP were adjusted and calibrated to reflect total square footage instead of gas square footage (as shown in Appendix A). The total energy usage for each segment corresponds to the values in Table 3-7.

Table 3-8 Commercial Sector Composite Natural Gas Market Profile, 2010/11

Average Market Profiles

End Use	Technology	Saturation	EUI (m3)	Intensity (m3/Sqft)	Usage (MMm3)
Heating	Furnace	72.1%	1.10	0.79	255.2
Heating	Boiler	14.7%	2.24	0.33	105.9
Water Heating	Water Heating	55.1%	0.48	0.26	84.6
Cooking	Oven	14.3%	0.07	0.01	3.4
Cooking	Fryer	14.3%	0.09	0.01	4.3
Cooking	Broiler	14.3%	0.09	0.01	4.3
Cooking	Griddle	14.3%	0.07	0.01	3.2
Cooking	Range	14.3%	0.08	0.01	3.8
Cooking	Steamer	14.3%	0.12	0.02	5.3
Misc	Pool Heater	1.2%	0.16	0.00	0.6
Misc	Misc	10.7%	0.45	0.05	15.3
	Total			**1.51**	**485.9**

Figure 3-13 illustrates the overall natural gas use by end use in the commercial sector as a whole. Space heating and water heating are the largest end uses, consuming 74% and 18% of commercial building natural gas use, respectively.

Figure 3-13 Commercial Natural Gas Use by End Use, 2010-2011

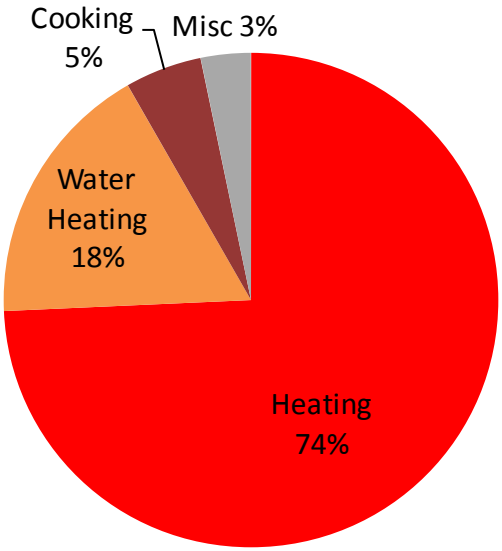
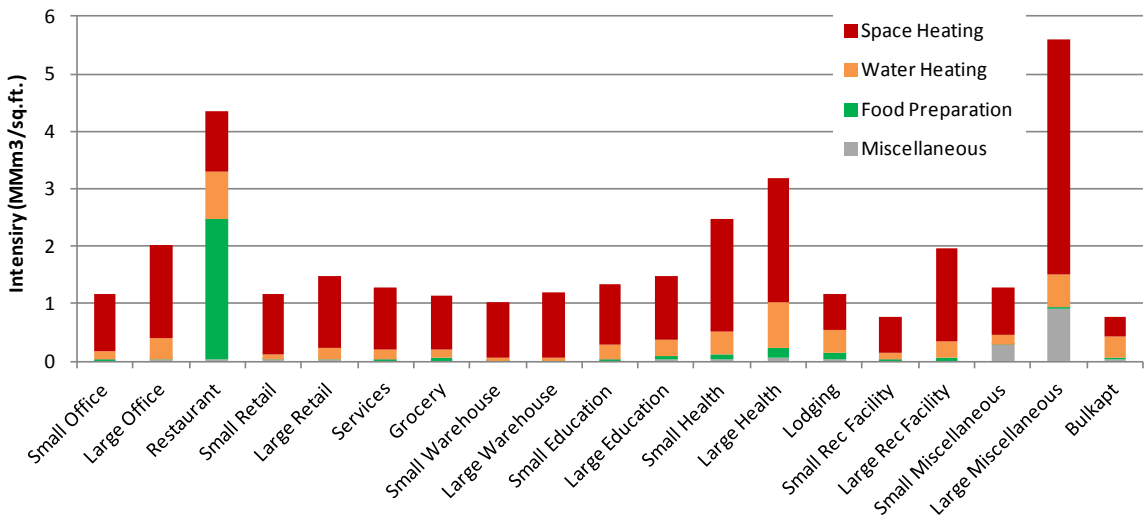


Figure 3-14 illustrates how the end-use composition of gas use varies by building type. Heating is the major end use across all building types. Cooking is a substantial use in restaurants.

Figure 3-14 Commercial End Use Gas Intensities by Building Type, 2010/11



Industrial Sector

This section characterizes the industrial market at the segment level, and then provides a profile of how each segment uses electricity and natural gas by end use.

Electricity Use

The industrial sector, at 7,576 GWh in 2010/11, accounts for over one-third of total electricity sales. Table 3-9 presents annual electric use and share of total sector use for each segment. Chemicals and primary metals are the two largest industries accounting for 58% of total industrial sales in 2010/11.

Table 3-9 Industrial Sector Electric Market Characterization Results, 2010/11

Segment	Sales (GWh)	Share of Total Sector Use (%)
Mining	138	1.8%
Food and Beverage	459	6.1%
Pulp and Paper	290	3.8%
Chemical	2,224	29.4%
Petroleum	781	10.3%
Primary Metals	2,159	28.5%
Misc. Industrial	459	6.1%
Other Agriculture	616	8.1%
Other Industrial	451	5.9%
Total	**7,576**	**100%**

As with the residential and commercial sectors, the industrial market profiles characterize electricity use in terms of end use and technology for the base year 2010/11. Table 3-10 shows the composite market profiles for the industrial sector.

Market profiles for each segment are presented in Appendix A.

Table 3-10 Industrial Composite Electric Market Profile, 2010/11

	Average Market Profiles	
End Use	**Technology**	**Usage (GWh)**
Cooling	Air-Cooled Chiller	23.2
Cooling	Water-Cooled Chiller	69.8
Cooling	Roof top AC	238.5
Cooling	Other Cooling	17.4
Heating	Electric Heating	77.5
Ventilation	Ventilation	30.5
Interior Lighting	Screw-in	41.4
Interior Lighting	High-Bay Fixtures	24.1
Interior Lighting	Linear Fluorescent	382.8
Exterior Lighting	Screw-in	0.0
Exterior Lighting	HID	83.6
Exterior Lighting	Linear Fluorescent	0.0
Pumps	Pumps	431.4
Fans & Blowers	Fans & Blowers	337.7
Compressed Air	Compressed Air	269.6
Conveyors	Conveyors	371.3
Other Motors	Other Motors	1,313.7
Process Heating	Process Heating	1,287.7
Process Cooling and Refrigeration	Process Cooling and Refrigeratio	361.0
Electro-Chemical Processes	Electro-Chemical Processes	1,861.2
Other Process	Other Process	116.1
Misc	Misc	237.9
	Total	**7,576.3**

Figure 3-15 presents the end-use breakout for the industrial sector in 2010/11. The machine drive end use is the largest overall for the industrial sector, accounting for 35% of energy use. Note that a wide range of industrial equipment, such as air compressors and refrigeration compressors, pumps, and fans are included within the machine drive category. Electro-chemical process and process heating account for 25% and 17% of energy use, respectively. Lighting, heating, ventilation, and cooling, process cooling, and miscellaneous are each less than 10%.

Figure 3-15 Industrial Electricity Use by End Use, 2010/11

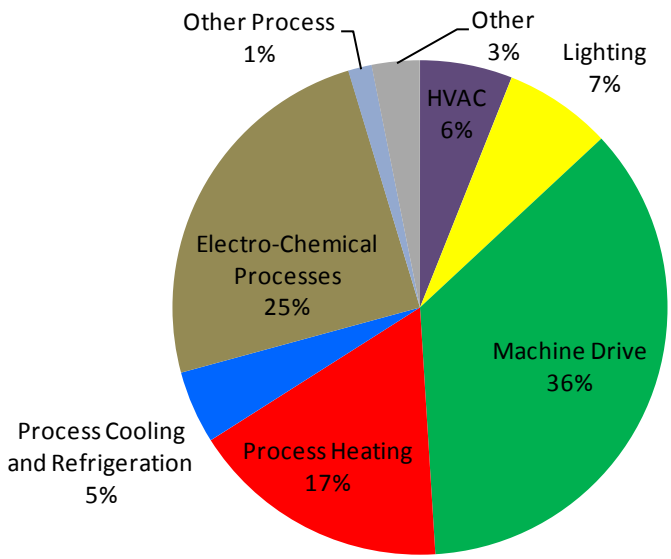
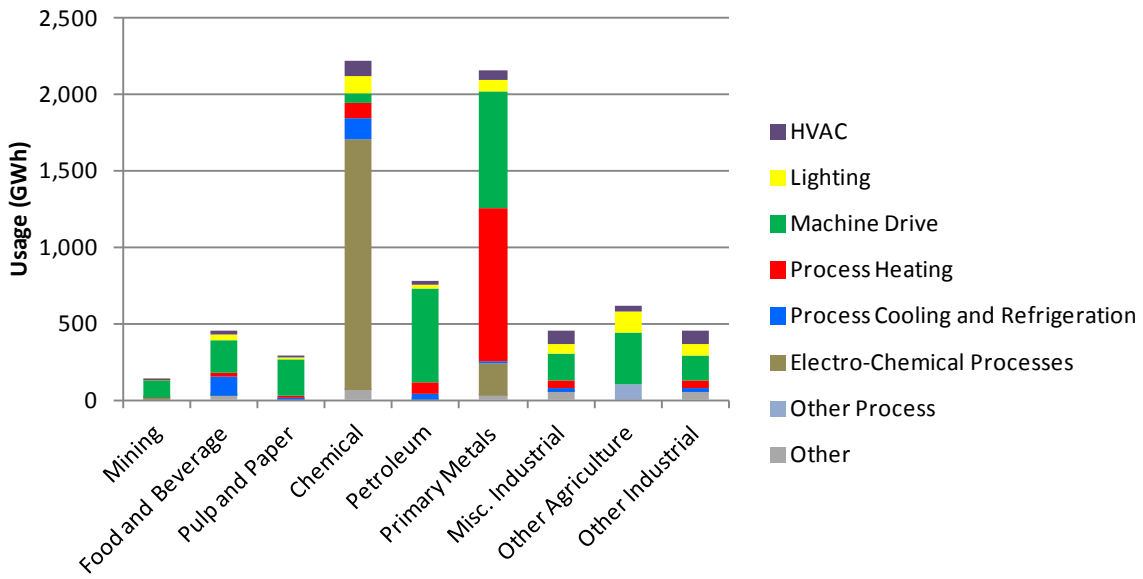


Figure 3-16 show how the major industrial segments used electricity in 2010/11. Machine drives (pumps, fans, blowers, compressed air, etc.) is prevalent among all segments, although electro-chemical process is more dominant in the chemical segment and process heating is more dominant in primary metals.

Figure 3-16 Industrial Electricity Use by End Use and Segment, 2010/11



Natural Gas Use

Total industrial natural gas use in 2010/11 was 509 MMm^3. Table 3-11 presents the employees, intensity estimates, and annual gas use for each industrial segment. The three largest segments are chemicals, food and beverage, and miscellaneous industrial.

Table 3-11 Industrial Sector Natural Gas Market Characterization Results, 2010/11

Segment	Sales (MMm^3)	Share of Total Sector Sales (%)
Mining	0.9	0.2%
Food and Beverage	172.6	33.9%
Pulp and Paper	4.4	0.9%
Chemical	150.7	29.6%
Petroleum	4.7	0.9%
Primary Metals	37.8	7.4%
Misc. Industrial	71.5	14.1%
Other Agriculture	18.8	3.7%
Other Industrial	47.4	9.3%
Total	**508.9**	**100%**

Table 3-12 shows the natural gas market profile for the industrial sector as a whole, representing a composite of all the building types. Boilers, furnaces, and process heating are the three largest energy consuming technologies in the industrial sector.

Table 3-12 Industrial Sector Composite Natural Gas Market Profile, 2010/11

	Average Market Profiles	
End Use	**Technology**	**Usage (10^6 m3)**
Heating	Furnace	128.5
Heating	Boiler	178.3
Heating	Other Heating	0.0
Process Heating	Process Heating	143.1
Process Cooling	Process Cooling	1.5
Other Process	Other Process	5.0
Misc	Misc	52.5
Total		**508.9**

Figure 3-17 illustrates the overall natural gas use by end use in the industrial sector as a whole. Space heating and process heating are the largest end uses, consuming 60% and 28% of industrial building natural gas use, respectively.

Figure 3-17 Industrial Gas Use by End Use, 2010/11

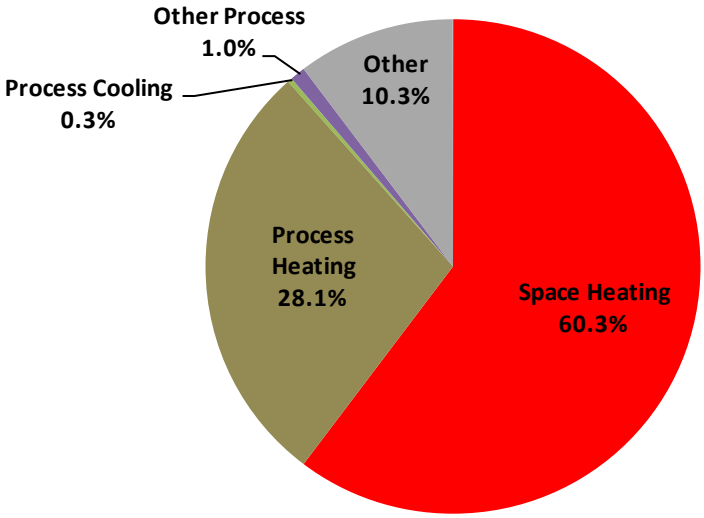
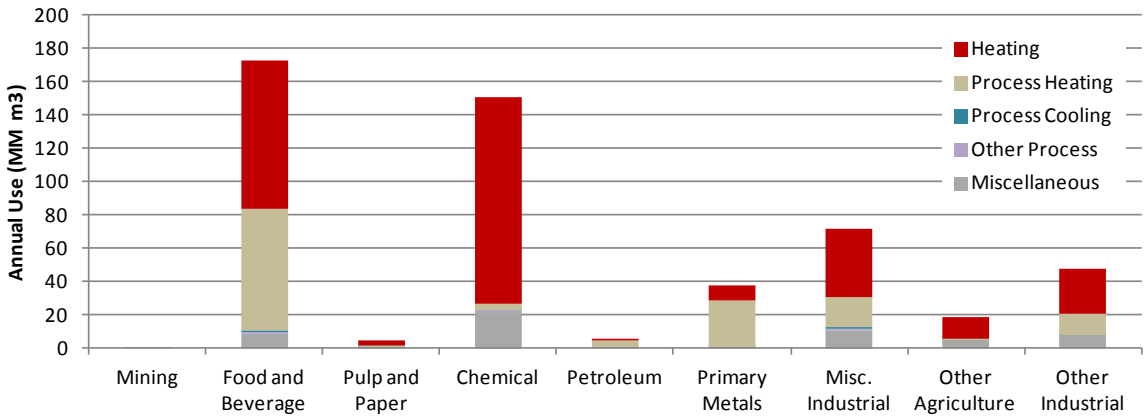


Figure 3-18 illustrates how the end-use composition of gas use varies by building type. Heating is the major end use across most segments. Process heating is a substantial use in food & beverage and primary metals.

Figure 3-18 Industrial Gas Use by End Use and Segment, 2010/11



CHAPTER | 4

BASELINE FORECAST

Prior to developing estimates of energy-efficiency potential, a baseline end-use forecast was developed to quantify how electricity and natural gas are used by end use in the base year and what the consumption is likely to be in the future in absence of new utility programs and naturally occurring efficiency. The baseline forecast serves as the metric against which energy efficiency potentials. The first part of this section focuses on electricity, followed by the forecasts for natural gas.

Baseline Forecast for Electricity

In this section, the baseline end-use forecasts for the residential, commercial and industrial sectors are presented. This is followed by the combined forecast across all sectors.

Residential Sector

The baseline forecast incorporates assumptions about economic growth, electricity prices, and appliance/equipment standards and building codes that are already mandated.

Figure 4-1 presents the baseline forecast at the end-use level for the residential sector as a whole. Overall, residential use increases from 6,952 GWh in 2010/11 to 8,831 GWh in 2031/32, an increase of 27%, or an average growth of 1.1% per year.

Figure 4-1 Residential Baseline Forecast by End Use

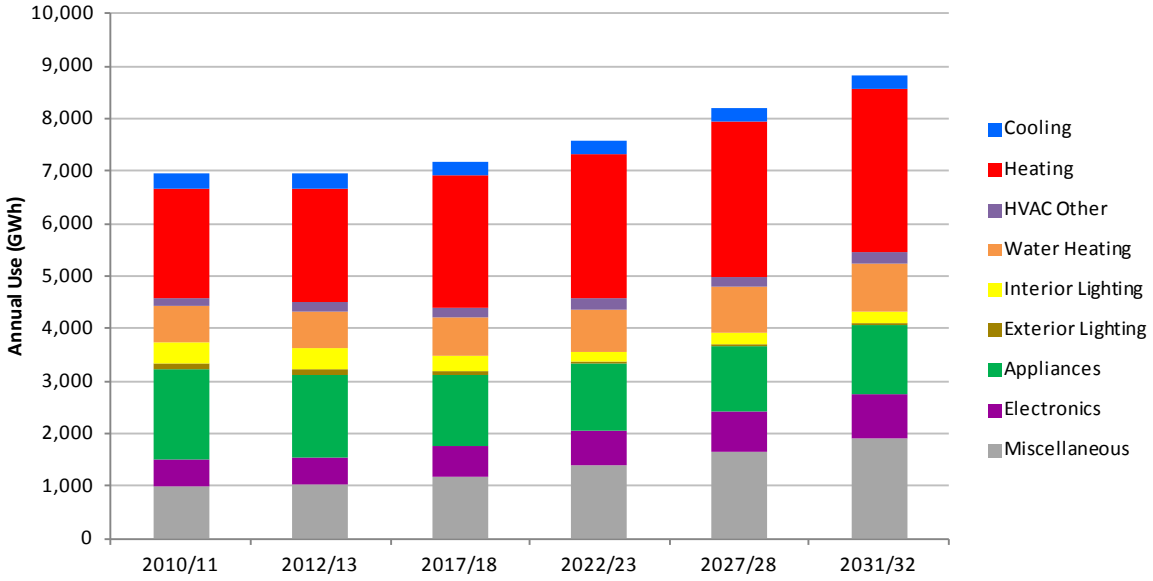


Figure 4-2 presents the forecast of use per household.

Figure 4-2 Residential Baseline Electricity Use per Household by End Use

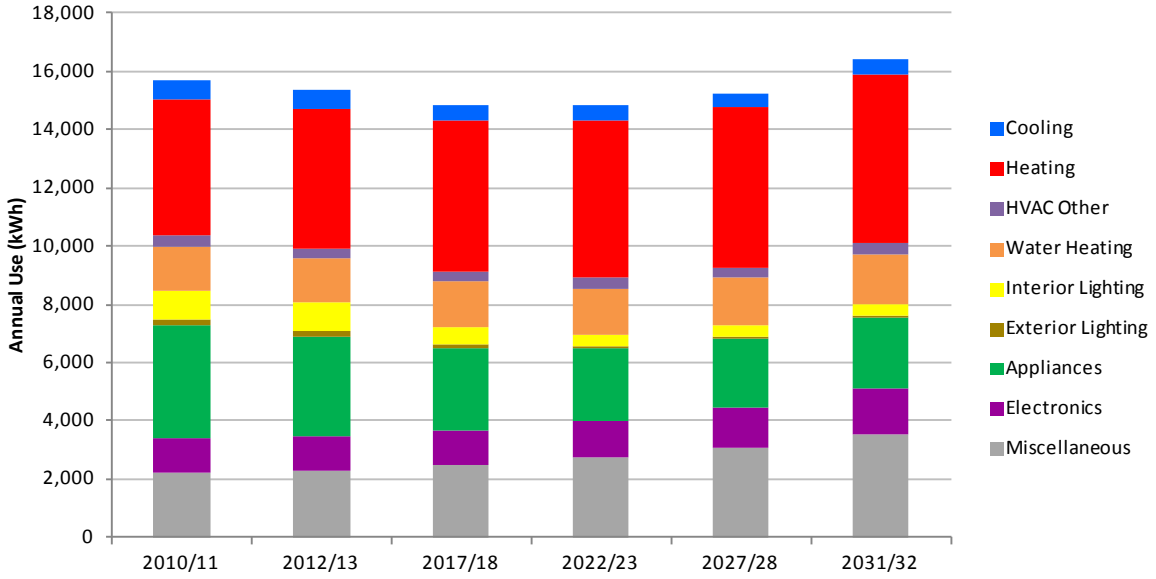


Table 4-1 shows the end-use forecast at the technology level. Specific observations include:

1. The primary reason for the reduction in the interior lighting is the federal lighting standards that have already been implemented in the U.S. and are anticipated in 2014 for Canada. The standard phases general service incandescent lamps out of the market over a three-year period. It causes a decline in interior screw-in lighting use by 60% over the forecast period.
2. Electric heating increases over the forecast period due to the increase in furnaces and conversion to geothermal heat pumps.
3. Appliance energy use decreases markedly, reflecting efficiency gains from standards, particularly in refrigeration appliances.
4. Growth in use in electronics is substantial and reflects an increase in the saturation of electronics and the trend toward higher-powered computers. This is tempered somewhat by the higher efficiency of televisions.
5. Growth in miscellaneous use is also substantial. This use includes various plug loads not elsewhere classified (e.g., hair dryers, power tools, coffee makers, etc.). This end use has grown consistently in the past and we incorporate future growth assumptions that are consistent with historical trends.

Table 4-1 Residential Baseline Electricity Forecast by End Use and Technology (GWh)

End Use	Technology	2010/11	2012/13	2017/18	2022/23	2031/32	% Change	Avg. Growth Rate
Cooling	Central AC	244	257	232	226	234	-4%	-0.2%
	Evaporative AC	32	35	33	32	31	-3%	-0.1%
	Room AC	1	2	2	2	3	95%	3.2%
	Geothermal Heat Pump	-	-	-	-	-	0%	0.0%
Heating	Geothermal Heat Pump	1,225	1,271	1,469	1,635	1,850	51%	2.0%
	Furnace	65	68	83	95	113	74%	2.6%
	Boiler	67	75	104	130	168	150%	4.4%
	Electric Resistance	648	664	737	791	849	31%	1.3%
	Supplemental Heat	75	82	102	115	130	73%	2.6%
HVAC Other	Central Exhaust	16	16	20	23	28	78%	2.8%
	Electronic Air Cleaner	47	45	48	50	53	14%	0.6%
	Humidifier	42	41	43	46	49	18%	0.8%
	Dehumidifier	66	65	67	70	75	14%	0.6%
Water Heating	Water Heater	670	687	754	821	935	40%	1.6%
	Water Heater - Tankless	2	2	2	3	4	86%	3.0%
Interior Lighting	Screw-in	394	397	242	159	172	-56%	-4.0%
	Linear Fluorescent	30	30	32	33	35	18%	0.8%
Exterior Lighting	Screw-in	91	88	63	39	41	-55%	-3.8%
Appliances	Clothes Washer	150	130	91	63	52	-65%	-5.1%
	Clothes Dryer	308	288	263	250	255	-17%	-0.9%
	Dishwasher	89	79	66	63	67	-25%	-1.3%
	Refrigerator	355	304	237	206	204	-43%	-2.6%
	Freezer	234	201	158	144	150	-36%	-2.1%
	Second Refrigerator	235	207	171	155	151	-36%	-2.1%
	Second Freezer	65	60	52	48	47	-28%	-1.6%
	Stove	258	263	278	293	317	23%	1.0%
	Microwave	39	40	43	46	51	29%	1.2%
Electronics	Personal Computers	103	110	128	149	193	87%	3.0%
	Monitor	19	20	23	26	34	79%	2.8%
	Laptops	16	17	21	25	32	98%	3.3%
	TVs	165	167	179	189	239	45%	1.8%
	Printer/Fax/Copier	15	17	20	24	30	96%	3.2%
	Set-top Boxes/DVR	193	197	218	252	326	69%	2.5%
Misc.	Pool Pump	39	40	43	46	50	28%	1.2%
	Pool Heater	31	30	26	21	18	-43%	-2.7%
	Hot Tub / Spa	87	91	102	114	134	53%	2.0%
	Well Pump	30	31	35	38	44	45%	1.8%
	Furnace Fan	408	406	430	454	494	21%	0.9%
	Sewage Pump	2	2	2	2	3	50%	1.9%
	Sump Pump	3	3	4	4	5	64%	2.4%
	Pressure Pump	35	36	39	42	47	33%	1.3%
	Sauna	18	19	20	22	24	32%	1.3%
	Car Block Heaters	43	42	44	46	51	20%	0.9%
	Car Warmers	7	7	7	8	8	21%	0.9%
	Electric Vehicles	0	1	5	14	74	n/a	34.7%
	Miscellaneous	289	322	432	578	962	233%	5.7%
Total		**6,952**	**6,955**	**7,168**	**7,592**	**8,831**	**27%**	**1.1%**

Commercial Sector

Electricity use in the commercial sector remains essentially flat during the forecast horizon, an average of -0.03% per year. Usage starts at 5,685 GWh in 2010/11, decreases until 2016/17 and then increases to 5,655 GWh in 2031/32. Figure 4-3 and Table 4-2 present the baseline forecast at the end-use level for the commercial sector as a whole. Most end uses show modest growth over the forecast period. The exceptions are interior lighting, which declines due to the lighting standards, and refrigeration, which is affected by the standards for refrigeration.

Figure 4-3 Commercial Baseline Electricity Forecast by End Use

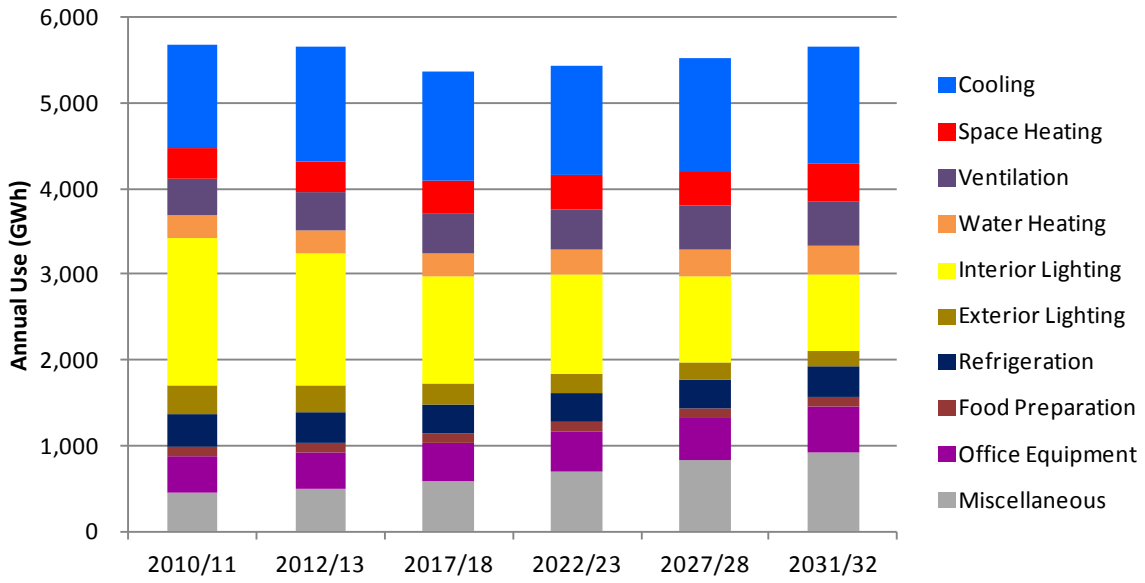


Table 4-2 Commercial Electricity Consumption by End Use (GWh)

End Use	2010/ 11	2012/ 13	2017/ 18	2022/ 23	2027/ 28	2031/ 32	% Change	Avg. Growth Rate
Cooling	1,212	1,324	1,273	1,278	1,314	1,370	13%	0.6%
Space Heating	362	368	385	401	419	431	19%	0.8%
Ventilation	429	441	462	479	502	529	23%	1.0%
Water Heating	252	258	275	294	313	328	30%	1.2%
Interior Lighting	1,734	1,558	1,238	1,149	1,006	893	-48%	-3.2%
Exterior Lighting	337	297	240	228	198	174	-48%	-3.1%
Refrigeration	375	372	349	339	341	355	-5%	-0.3%
Food Preparation	111	110	110	114	120	125	12%	0.6%
Office Equipment	416	424	434	453	486	520	25%	1.1%
Miscellaneous	457	493	595	707	828	929	104%	3.4%
Total	**5,685**	**5,646**	**5,361**	**5,441**	**5,527**	**5,655**	**-1%**	**0.0%**

Table 4-3 presents the commercial sector forecast by technology. Interior screw-in lighting decreases significantly over the forecast period as a result of the lighting standard.

Table 4-3 Commercial Baseline Electricity Forecast by End Use and Technology (GWh)

End Use	Technology	2010/ 11	2012/ 13	2017/ 18	2022/ 23	2027/ 28	2031/32	% Change
Cooling	Air-Cooled Chiller	85	99	106	112	117	122	43.9%
	Water-Cooled Chiller	265	288	285	290	293	305	15.0%
	Roof top AC	573	621	594	592	613	643	12.2%
	Roof top Heat Pump	98	107	98	98	103	108	9.9%
	Other Cooling	191	209	191	185	187	192	0.8%
Space Heating	Roof top Heat Pump	121	119	114	115	120	124	2.1%
	Electric Heating	241	249	271	286	299	307	27.6%
Ventilation	Ventilation	429	441	462	479	502	529	23.2%
Water Heating	Water Heating	252	258	275	294	313	328	30.0%
Interior Lighting	Screw-in	725	636	358	288	224	188	-74.1%
	Linear Fluorescent	859	795	771	764	707	644	-25.0%
	High-Bay Fixtures	150	128	108	96	74	61	-59.2%
Exterior Lighting	Screw-in	42	72	35	30	25	18	-56.3%
	Linear Fluorescent	19	21	24	28	33	36	89.3%
	HID	275	205	181	169	141	120	-56.6%
Refrigeration	Walk-in Refrigerator	135	128	109	100	103	111	-18.1%
	Reach-in Refrigerator	9	8	8	7	8	8	-5.8%
	Glass Door Display	182	184	173	164	155	153	-15.9%
	Open Display Case	27	29	31	34	36	38	40.6%
	Icemaker	19	20	23	26	29	32	63.8%
	Vending Machine	3	3	5	7	10	13	376.6%
Food Preparation	Dishwasher	51	50	46	47	49	51	-1.0%
	Oven	22	22	24	26	27	29	32.5%
	Fryer	29	29	32	35	38	40	38.7%
	Hot Food Container	10	9	7	6	6	6	-39.2%
Office Equipment	Monitor	45	45	47	52	56	59	32.3%
	Desktop Computer	242	247	242	244	261	277	14.3%
	Laptop	35	37	39	41	42	42	19.3%
	Server	50	53	64	74	83	95	90.6%
	Printer/Copier/Fax	32	32	32	33	36	38	20.1%
	POS Terminal	12	11	11	9	8	9	-25.5%
Miscellaneous	Pool Pump	1	1	1	1	1	1	28.6%
	Pool Heater	0	0	0	0	0	0	-67.1%
	Miscellaneous	227	255	333	422	518	601	43.2%
	Non-HVAC Motors	228	237	261	285	308	327	164.5%
Total		**5,685**	**5,646**	**5,361**	**5,441**	**5,527**	**5,655**	**-0.5%**

Industrial Sector

Figure 4-4 and Table 4-4 present the baseline forecast at the end-use level for the industrial sector as a whole. Overall, industrial annual energy use increases from 7,576 GWh in 2010/11 to 9,304 GWh in 2031/32, a 23% increase, or 1.0% average growth per year.

Figure 4-4 Industrial Baseline Electricity Forecast by End Use

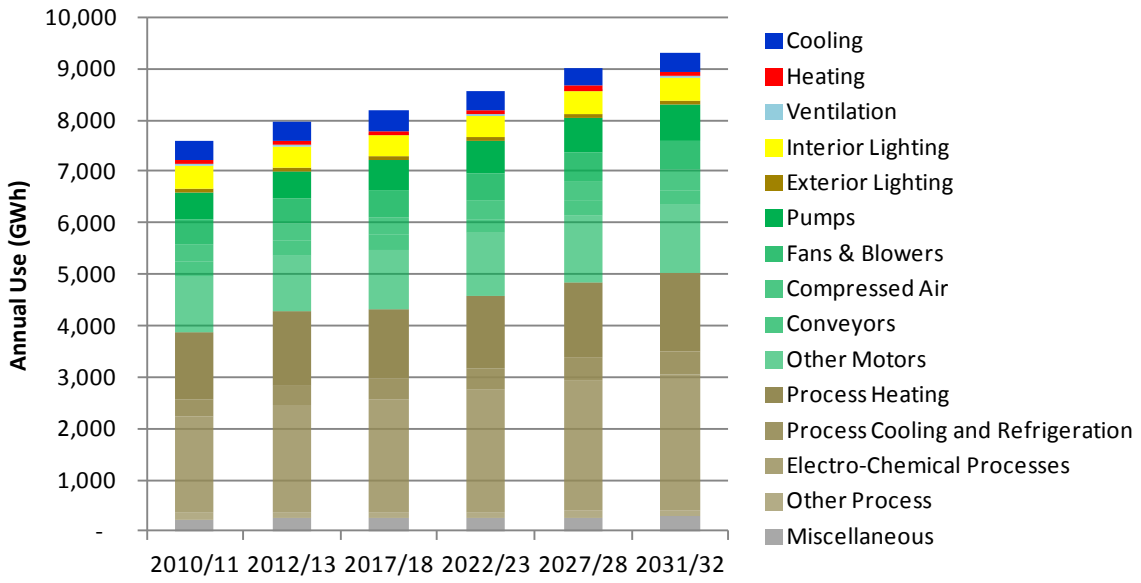


Table 4-4 Industrial Electricity Consumption by End Use (GWh)

End Use	2010/11	2012/13	2017/18	2022/23	2027/28	2031/32	% Change	Avg. Growth Rate
Cooling	349	400	380	366	361	363	4%	0.2%
Heating	78	75	77	80	83	84	9%	0.4%
Ventilation	30	29	25	25	26	26	-14%	-0.7%
Interior Lighting	448	420	413	427	445	454	1%	0.1%
Exterior Lighting	84	64	58	61	63	64	-23%	-1.2%
Pumps	524	515	611	641	684	711	36%	1.4%
Fans & Blowers	481	484	504	519	542	557	16%	0.7%
Compressed Air	333	330	348	365	388	402	21%	0.9%
Conveyors	296	303	272	276	284	289	-3%	-0.1%
Other Motors	1,089	1,096	1,179	1,224	1,289	1,331	22%	1.0%
Process Heating	1,288	1,421	1,322	1,393	1,468	1,513	18%	0.8%
Process Cooling and Refrig.	361	384	419	440	462	476	32%	1.3%
Electro-chemical Processes	1,861	2,089	2,192	2,350	2,519	2,623	41%	1.6%
Other Process	116	118	121	124	127	129	11%	0.5%
Miscellaneous	238	250	256	265	275	281	18%	0.8%
Total	**7,576**	**7,978**	**8,177**	**8,556**	**9,016**	**9,304**	**23%**	**1.0%**

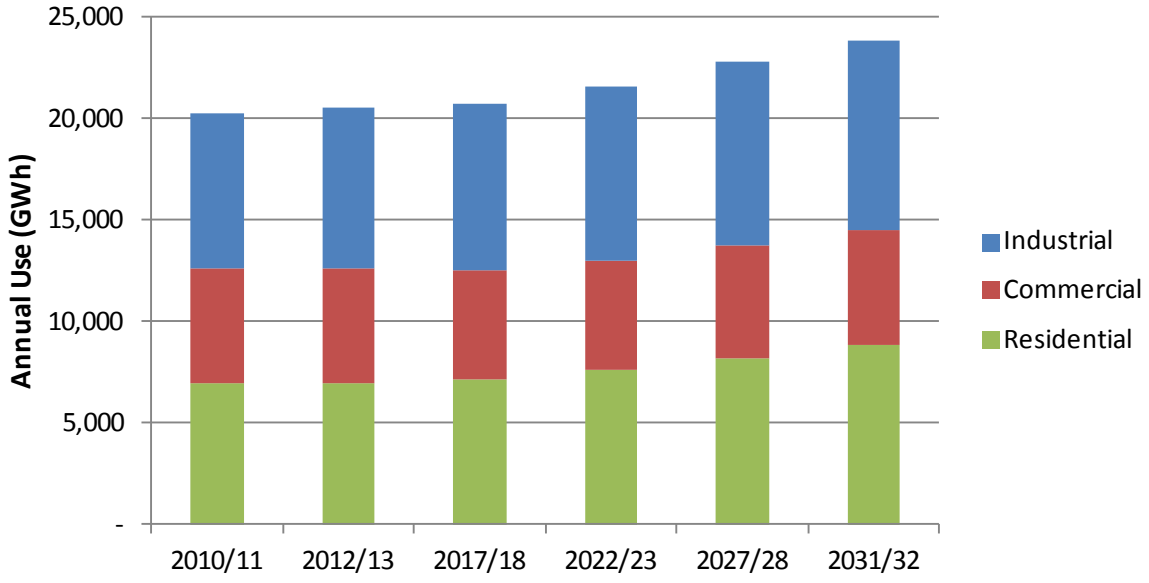
Electric Baseline Forecast Summary

Table 4-5 and Figure 4-5 provide a summary of the baseline forecast by sector and for Manitoba Hydro as a whole.

Table 4-5 Baseline Forecast Summary (GWh)

Sector	2010/11	2012/13	2017/18	2022/23	2027/28	2031/32	% Change	Avg. Growth Rate
Residential	6,952	6,955	7,168	7,592	8,215	8,831	27.0%	1.3%
Commercial	5,685	5,646	5,361	5,441	5,527	5,655	-0.5%	-0.0%
Industrial	7,576	7,978	8,177	8,556	9,016	9,304	22.8%	1.1%
Total	**20,213**	**20,580**	**20,706**	**21,589**	**22,757**	**23,790**	**17.7%**	**0.9%**

Figure 4-5 Baseline Forecast Summary (GWh)



Baseline Forecast for Natural Gas

In this section, the baseline natural gas forecasts for the residential, commercial and industrial sectors are presented. This is followed by the combined forecast across all sectors.

Residential Sector

The baseline forecast incorporates assumptions about economic growth, natural gas prices, and appliance/equipment standards and building codes that are already mandated.

Figure 4-1 presents the baseline forecast at the end-use level for the residential sector as a whole. Overall, residential use increases from 590 MMm^3 in 2010/11 to 551 MMm^3 in 2031/32, a decrease of 7%, or an average growth of -0.3% per year.

Figure 4-6 Residential Baseline Forecast by End Use

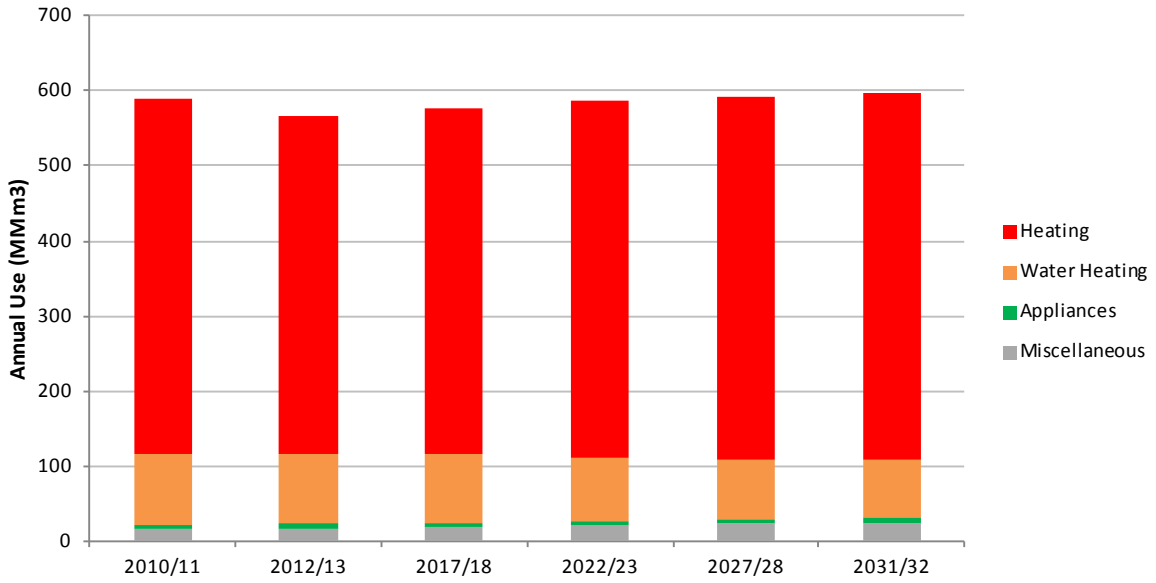


Figure 4-7 presents the forecast of use per household. Most noticeable is that water heating use decreases over the forecast period.

Figure 4-7 Residential Baseline Natural Gas Use per Household by End Use

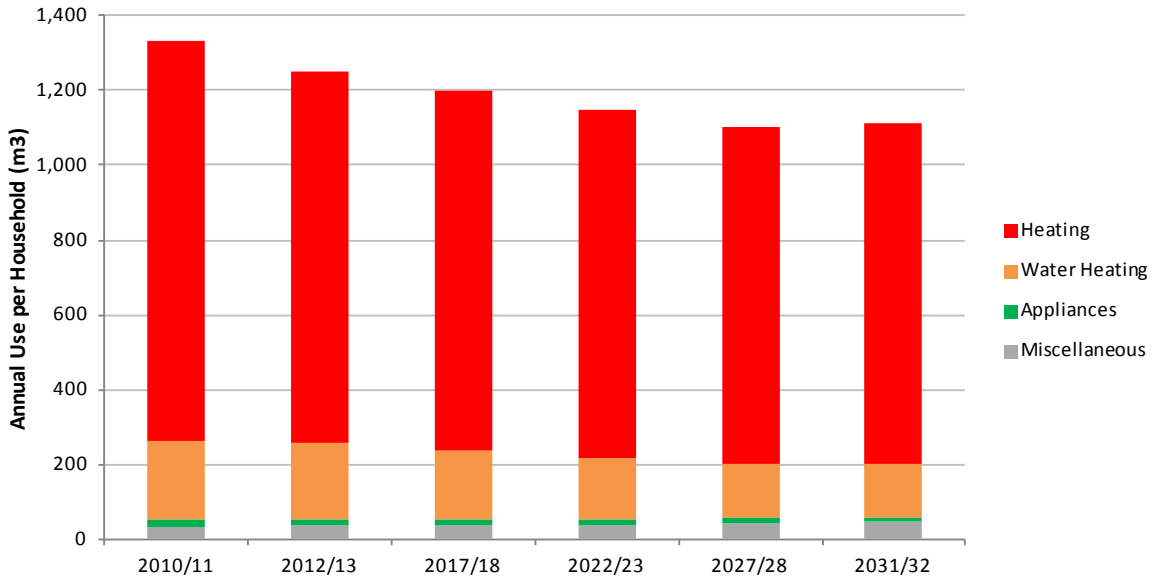


Table 4-1Table 4-6 shows the end-use forecast at the technology level. The primary reason for the reduction in the baseline forecast beginning in 2012 is the federal furnace standards. It causes a decline in furnace use through 2017/18 before it picks back up again due to customer growth. Water heating use also decreases by 20% due to standards for water heating technology.

Table 4-6 Residential Baseline Natural Gas Forecast by End Use and Technology (MMm^3)

End Use	Technology	2010/11	2012/13	2017/18	2022/23	2027/28	2031/32	% Change	Avg. Growth Rate
Heating	Furnace	430	408	419	430	439	445	3%	0.2%
	Boiler	34	33	33	33	33	33	-4%	-0.2%
	Supplemental Heat	10	10	11	11	12	13	26%	1.1%
Water Heating	Water Heater	94	94	91	85	79	75	-20%	-1.0%
Appliances	Clothes Dryer	3	3	2	2	2	2	-42%	-2.6%
	Stove	4	4	5	5	5	6	40%	1.6%
Miscellaneous	Pool Heater	12	12	14	16	18	20	75%	2.7%
	Gas Barbeque	1	1	1	2	2	2	97%	3.2%
	Miscellaneous	3	3	3	3	3	3	-2%	-0.1%
Total		**590**	**567**	**578**	**587**	**593**	**598**	**1%**	**0.1%**

Commercial Sector

Natural gas use in the commercial sector grows modestly at 8% overall during the forecast horizon, an average of 0.4% per year. Usage starts at 486 MMm^3 in 2010/11, decreases until 2014/15 and then increases to 517 MMm^3 in 2031/32. Figure 4-3 and Table 4-2 present the baseline forecast at the end-use level for the commercial sector as a whole. Most end uses show modest growth over the forecast period, except for water heating which decreases 11%.

Figure 4-8 Commercial Baseline Natural Gas Forecast by End Use

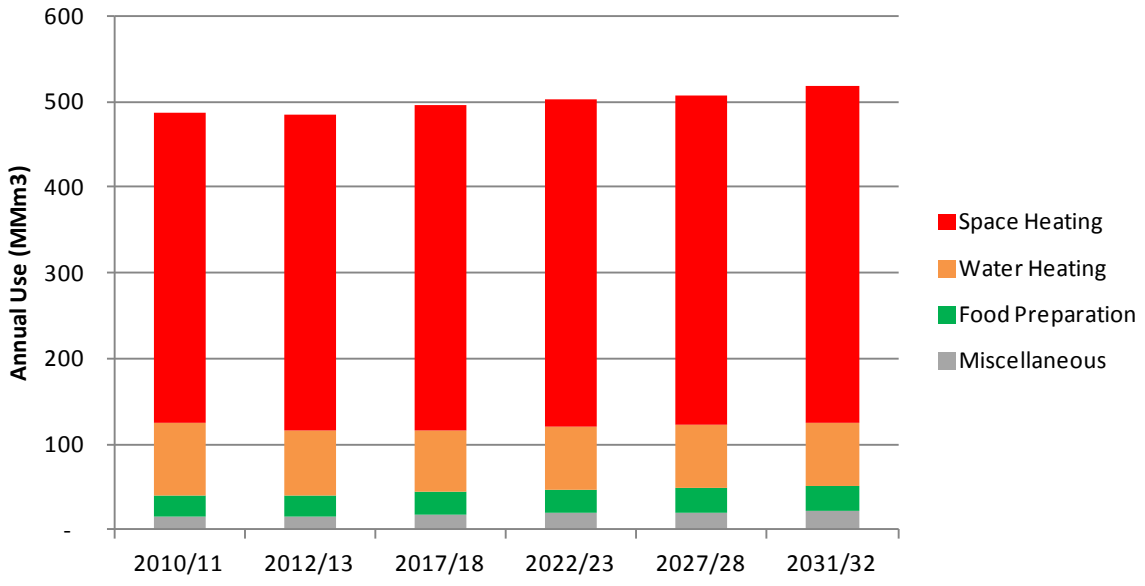


Table 4-7 Commercial Natural Gas Consumption by End Use (MMm^3)

End Use	2010/11	2012/13	2017/18	2022/23	2027/28	2031/32	% Change	Avg. Growth Rate
Space Heating	361	367	380	382	384	391	8%	0.4%
Water Heating	85	76	73	74	73	75	-11%	-0.5%
Food Preparation	24	25	26	27	28	29	18%	0.8%
Miscellaneous	16	17	18	19	21	22	38%	1.5%
Total	**486**	**484**	**497**	**502**	**506**	**517**	**6%**	**0.3%**

Table 4-8presents the commercial sector forecast by technology.

Table 4-8 Commercial Baseline Natural Gas Forecast by End Use and Technology (MMm^3)

End Use	Technology	2010/11	2012/13	2017/18	2022/23	2031/32	% Change	Avg. Growth Rate
Space Heating	Furnace	255	261	273	270	268	4.8%	0.2%
	Boiler	106	105	107	113	123	16.7%	0.7%
	Other Heating	-	-	-	-	-	0.0%	0.0%
Water Heating	Water Heating	85	76	73	74	75	-10.9%	-0.5%
Food Preparation	Oven	3	3	4	4	4	14.1%	0.6%
	Fryer	4	4	5	5	5	12.8%	0.6%
	Broiler	4	4	5	5	6	30.2%	1.3%
	Griddle	3	3	3	4	4	23.6%	1.0%
	Range	4	4	4	4	5	19.8%	0.9%
	Steamer	5	5	5	6	6	8.7%	0.4%
Miscellaneous	Pool Heater	1	1	1	1	1	35.9%	1.5%
	Miscellaneous	15	16	17	19	21	38.2%	1.5%
Total		**486**	**484**	**497**	**502**	**517**	**6.4%**	**0.3%**

Industrial Sector

Figure 4-4 and Table 4-4 present the baseline forecast at the end-use level for the industrial sector as a whole. Overall, industrial annual natural gas use increases from 509 MMm^3 in 2010/11 to 555 MMm^3 in 2031/32, a 9% increase, or 0.4% average growth per year.

Figure 4-9 Industrial Baseline Natural Gas Forecast by End Use

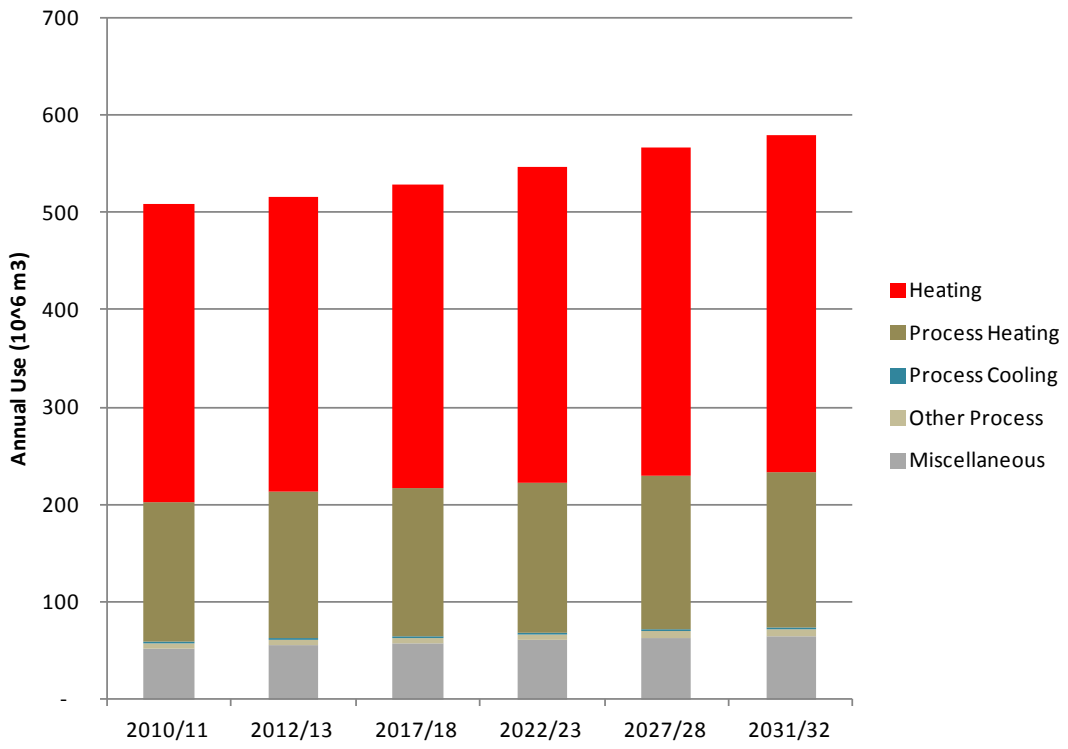


Table 4-9 Industrial Natural Gas Consumption by End Use (MMm³)

End Use	2010/11	2012/13	2017/18	2022/23	2027/28	2031/32	% Change	Avg. Growth Rate
Heating	307	304	307	311	317	321	5%	0.2%
Process Heating	143	151	151	155	158	161	12%	0.6%
Process Cooling	2	2	2	2	2	2	13%	0.6%
Other Process	5	5	5	6	6	6	19%	0.8%
Miscellaneous	52	56	58	61	63	65	24%	1.0%
Total	**509**	**517**	**524**	**533**	**546**	**555**	**9%**	**0.4%**

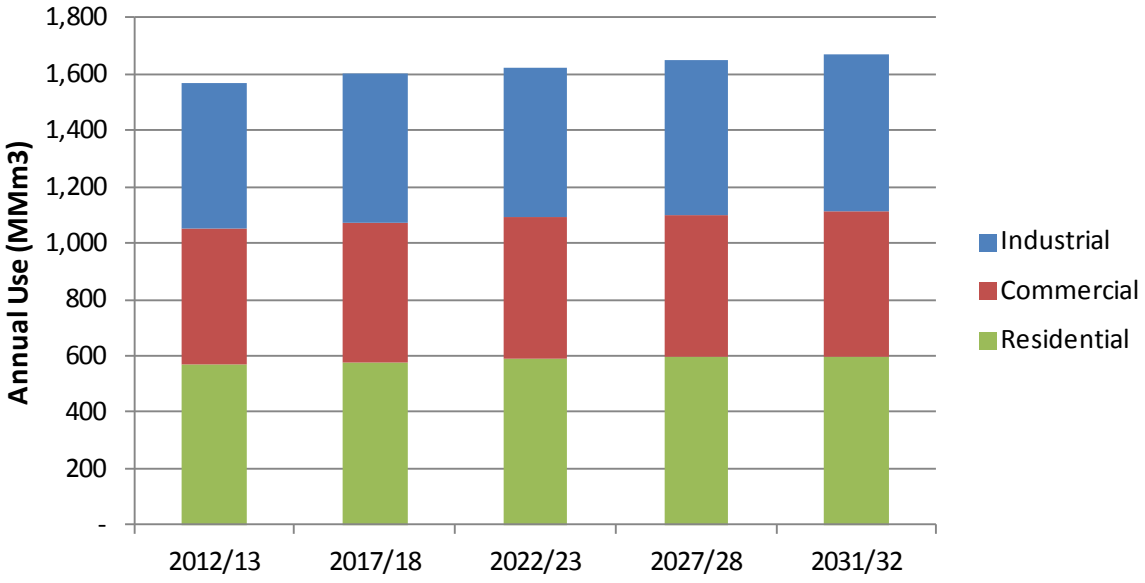
Natural Gas Baseline Forecast Summary

Table 4-5 and Figure 4-5 provide a summary of the baseline forecast by sector and for Manitoba Hydro as a whole.

Table 4-10 Natural Gas Baseline Forecast Summary (MMm³)

Sector	2010/11	2012/13	2017/18	2022/23	2027/28	2031/32	% Change	Avg. Growth Rate
Residential	590	567	578	587	593	598	1.4%	0.1%
Commercial	486	484	497	502	506	517	6.4%	0.3%
Industrial	509	517	524	533	546	555	9.0%	0.5%
Total	**1,585**	**1,567**	**1,598**	**1,623**	**1,645**	**1,670**	**5.4%**	**0.3%**

Figure 4-10 Natural Gas Baseline Forecast Summary (MMm³)



CHAPTER | 5

ENERGY EFFICIENCY MEASURES

List of Energy Efficiency Measures

The first step of the energy efficiency measure analysis is to identify the list of all relevant energy efficiency measures that should be considered for the potential assessment. For this study, EnerNOC prepared a preliminary list of measures for Manitoba Hydro to review. After incorporating feedback, we populated the full databases for the three sectors.

Sources for the measure assumptions were drawn from Manitoba Hydro' programs, EnerNOC's building modeling tool BEST, and EnerNOC's other measure databases from previous studies and program work.

- **Residential Measures**. The residential measures span all end uses and vary significantly in the manner in which they impact energy consumption. Table 5-1 shows the residential equipment measure options and the segments for which they were modeled. Table 5-2 shows the residential non-equipment measure options. Not all measures were considered for existing and new construction. An "X" indicates that the non-equipment measure was considered for the vintage type indicated in the column. All residential measures considered for this study are described in Appendix B.
- **Commercial Measures**. Table 5-3 and Table 5-4 present a summary of the commercial equipment and non-equipment measures, respectively. The measures shown were modeled for nearly all of the commercial building types, both new and existing, with only a few exceptions. For instance, hotel guestroom controls were only modeled for the lodging sector. All commercial measures considered for this study are described in Appendix C.
- **Industrial Measures**. Table 5-5 and Table 5-6 present a summary of the industrial equipment and non-equipment measures, respectively. All industrial measures considered for this study are described in Appendix D.

Table 5-1 Summary of Residential Equipment Measures

End Use	Fuel	Technology	Efficiency Option
Cooling	Electric	Central AC	SEER 13
Cooling	Electric	Central AC	SEER 14 (Energy Star)
Cooling	Electric	Central AC	SEER 15 (CEE Tier 2)
Cooling	Electric	Central AC	SEER 16 (CEE Tier 3)
Cooling	Electric	Central AC	Ductless Minisplit
Cooling	Electric	Central AC	SEER 21
Cooling	Electric	Evaporative AC	Direct
Cooling	Electric	Evaporative AC	Indirect
Cooling	Electric	Evaporative AC	Indirect/Direct
Cooling	Electric	Room AC	EER 9.8
Cooling	Electric	Room AC	EER 10.8 (Energy Star)
Cooling	Electric	Room AC	EER 11.0

End Use	Fuel	Technology	Efficiency Option
Cooling	Electric	Room AC	EER 12.0
Cooling	Electric	Geothermal Heat Pump	EER 13.2, COP 3.1
Cooling	Electric	Geothermal Heat Pump	EER 14.1, COP 3.3
Cooling	Electric	Geothermal Heat Pump	EER 16, COP 3.5
Cooling	Electric	Geothermal Heat Pump	EER 18, COP 3.8
Cooling	Electric	Geothermal Heat Pump	EER 30, COP 5.0
Heating	Electric	Geothermal Heat Pump	EER 13.2, COP 3.1
Heating	Electric	Geothermal Heat Pump	EER 14.1, COP 3.3
Heating	Electric	Geothermal Heat Pump	EER 16, COP 3.5
Heating	Electric	Geothermal Heat Pump	EER 18, COP 3.8
Heating	Electric	Geothermal Heat Pump	EER 30, COP 5.0
Heating	Electric	Electric Resistance	Standard
Heating	Electric	Furnace	Standard
Heating	Electric	Boiler	Standard
Heating	Electric	Supplemental Heat	Standard
HVAC Other	Electric	Central Exhaust	Standard
HVAC Other	Electric	Central Exhaust	Efficient
HVAC Other	Electric	Electronic Air Cleaner	Standard
HVAC Other	Electric	Electronic Air Cleaner	Energy Star
HVAC Other	Electric	Humidifier	Standard
HVAC Other	Electric	Humidifier	Efficient
HVAC Other	Electric	Dehumidifier	Standard
HVAC Other	Electric	Dehumidifier	Energy Star
Water Heating	Electric	Water Heater	EF 0.9
Water Heating	Electric	Water Heater	EF 0.95
Water Heating	Electric	Water Heater - Tankless	Standard
Interior Lighting	Electric	Screw-in	Incandescent
Interior Lighting	Electric	Screw-in	Infrared Halogen
Interior Lighting	Electric	Screw-in	Infrared Halogen (2020)
Interior Lighting	Electric	Screw-in	CFL
Interior Lighting	Electric	Screw-in	LED
Interior Lighting	Electric	Screw-in	LED (2020)
Interior Lighting	Electric	Linear Fluorescent	T12
Interior Lighting	Electric	Linear Fluorescent	T8
Interior Lighting	Electric	Linear Fluorescent	Super T8

End Use	Fuel	Technology	Efficiency Option
Interior Lighting	Electric	Linear Fluorescent	T5
Interior Lighting	Electric	Linear Fluorescent	LED
Exterior Lighting	Electric	Screw-in	Incandescent
Exterior Lighting	Electric	Screw-in	Infrared Halogen
Exterior Lighting	Electric	Screw-in	Infrared Halogen (2020)
Exterior Lighting	Electric	Screw-in	CFL
Exterior Lighting	Electric	Screw-in	LED
Exterior Lighting	Electric	Screw-in	LED (2020)
Appliances	Electric	Clothes Washer	Standard (1.26)
Appliances	Electric	Clothes Washer	Energy Star (1.72)
Appliances	Electric	Clothes Washer	AHAM (MEF 1.72)
Appliances	Electric	Clothes Washer	Energy Star (MEF 2.0)
Appliances	Electric	Clothes Washer	AHAM (MEF 2.0)
Appliances	Electric	Clothes Washer	Compact (MEF 2.79)
Appliances	Electric	Clothes Dryer	Baseline
Appliances	Electric	Clothes Dryer	High Efficiency
Appliances	Electric	Clothes Dryer	Baseline (2015+)
Appliances	Electric	Clothes Dryer	High Efficiency (2015+)
Appliances	Electric	Dishwasher	Standard (EF 0.46)
Appliances	Electric	Dishwasher	Standard (EF 0.63)
Appliances	Electric	Dishwasher	Energy Star (EF 0.69)
Appliances	Electric	Dishwasher	Energy Star (EF 0.73)
Appliances	Electric	Dishwasher	AHAM (EF 0.73)
Appliances	Electric	Dishwasher	Ultra Efficient (EF 1.1)
Appliances	Electric	Refrigerator	Standard
Appliances	Electric	Refrigerator	Energy Star
Appliances	Electric	Refrigerator	High Efficiency
Appliances	Electric	Refrigerator	AHAM (2014)
Appliances	Electric	Refrigerator	High Efficiency (2014)
Appliances	Electric	Freezer	Standard
Appliances	Electric	Freezer	Energy Star
Appliances	Electric	Freezer	High Efficiency
Appliances	Electric	Freezer	AHAM (2014)
Appliances	Electric	Freezer	High Efficiency (2014)
Appliances	Electric	Second Refrigerator	Standard

End Use	Fuel	Technology	Efficiency Option
Appliances	Electric	Second Refrigerator	Energy Star
Appliances	Electric	Second Refrigerator	High Efficiency
Appliances	Electric	Second Refrigerator	AHAM (2014)
Appliances	Electric	Second Refrigerator	High Efficiency (2014)
Appliances	Electric	Second Freezer	Standard
Appliances	Electric	Second Freezer	Energy Star
Appliances	Electric	Second Freezer	High Efficiency
Appliances	Electric	Second Freezer	AHAM (2014)
Appliances	Electric	Second Freezer	High Efficiency (2014)
Appliances	Electric	Stove	Baseline
Appliances	Electric	Stove	Convection
Appliances	Electric	Stove	Halogen Burner
Appliances	Electric	Stove	Induction
Appliances	Electric	Microwave	Standard
Electronics	Electric	Personal Computers	Standard
Electronics	Electric	Personal Computers	Energy Star
Electronics	Electric	Monitor	Standard
Electronics	Electric	Monitor	Energy Star
Electronics	Electric	Laptops	Standard
Electronics	Electric	Laptops	Energy Star
Electronics	Electric	TVs	Standard
Electronics	Electric	TVs	Energy Star (3.1)
Electronics	Electric	TVs	Energy Star (4.1)
Electronics	Electric	TVs	Energy Star (5.1)
Electronics	Electric	Printer/Fax/Copier	Standard
Electronics	Electric	Printer/Fax/Copier	Energy Star
Electronics	Electric	Set-top Boxes/DVR	Standard
Electronics	Electric	Set-top Boxes/DVR	Energy Star (2009)
Electronics	Electric	Set-top Boxes/DVR	Energy Star (2011)
Miscellaneous	Electric	Pool Pump	Standard
Miscellaneous	Electric	Pool Pump	High Efficiency
Miscellaneous	Electric	Pool Pump	Two-Speed
Miscellaneous	Electric	Pool Heater	Electric Resistance
Miscellaneous	Electric	Pool Heater	Heat Pump (COP = 5.0)
Miscellaneous	Electric	Pool Heater	Solar

End Use	Fuel	Technology	Efficiency Option
Miscellaneous	Electric	Hot Tub / Spa	Standard
Miscellaneous	Electric	Hot Tub / Spa	Efficient Pumps
Miscellaneous	Electric	Hot Tub / Spa	Improved Controls and Pumps
Miscellaneous	Electric	Well Pump	Baseline (40% EF)
Miscellaneous	Electric	Well Pump	High Efficiency (60% EF)
Miscellaneous	Electric	Furnace Fan	Standard
Miscellaneous	Electric	Furnace Fan	ECM
Miscellaneous	Electric	Sewage Pump	Standard
Miscellaneous	Electric	Sewage Pump	Efficient
Miscellaneous	Electric	Sump Pump	Standard
Miscellaneous	Electric	Sump Pump	Efficient
Miscellaneous	Electric	Pressure Pump	Standard
Miscellaneous	Electric	Pressure Pump	Efficient
Miscellaneous	Electric	Sauna	Rock and Water
Miscellaneous	Electric	Sauna	Far Infrared
Miscellaneous	Electric	Car Block Heaters	Standard
Miscellaneous	Electric	Car Block Heaters	Timer
Miscellaneous	Electric	Car Warmers	Standard
Miscellaneous	Electric	Car Warmers	Timer
Miscellaneous	Electric	Electric Vehicles	Standard
Miscellaneous	Electric	Miscellaneous	Standard
Heating	Natural Gas	Furnace	AFUE 92%
Heating	Natural Gas	Furnace	AFUE 96%
Heating	Natural Gas	Boiler	EF 0.80
Heating	Natural Gas	Boiler	EF 0.82
Heating	Natural Gas	Boiler	EF 0.85
Heating	Natural Gas	Boiler	EF 0.95
Heating	Natural Gas	Supplemental Heat	Gas Fireplace
Water Heating	Natural Gas	Water Heater	EF 0.57
Water Heating	Natural Gas	Water Heater	EF 0.62
Water Heating	Natural Gas	Water Heater	EF 0.64
Water Heating	Natural Gas	Water Heater	EF 0.7
Water Heating	Natural Gas	Water Heater	EF 0.76
Water Heating	Natural Gas	Water Heater	Tankless
Water Heating	Natural Gas	Water Heater	EF 0.86

End Use	Fuel	Technology	Efficiency Option
Appliances	Natural Gas	Clothes Dryer	Standard
Appliances	Natural Gas	Clothes Dryer	Standard (AHAM)
Appliances	Natural Gas	Clothes Dryer	Efficient
Appliances	Natural Gas	Stove	Standard (EF .399)
Appliances	Natural Gas	Stove	Efficient (EF .42)
Miscellaneous	Natural Gas	Pool Heater	EF .78
Miscellaneous	Natural Gas	Pool Heater	EF .82
Miscellaneous	Natural Gas	Pool Heater	EF .90
Miscellaneous	Natural Gas	Gas Barbeque	Standard
Miscellaneous	Natural Gas	Miscellaneous	Standard

Table 5-2 Summary of Residential Non-equipment Measures

Measure	Existing	New Construction
Central Air Conditioner - Maintenance and Tune-Up	X	X
Attic Fan, Installation	X	X
Attic Fan, Photovoltaic	X	X
Ceiling Fan, Installation	X	X
Whole-House Fan, Installation	X	X
Furnace - Gas, Maintenance	X	X
Central Heat Pump - Maintenance	X	X
Insulation, Ducting	X	X
Ducting, Repair and Sealing	X	X
Insulation - Infiltration Control	X	
Insulation, Ceiling	X	
Insulation, Foundation	X	
Insulation, Wall Cavity	X	
Insulation, Wall Sheathing	X	
Doors, Storm and Thermal	X	X
Windows, ENERGY STAR	X	
Faucet Aerators	X	X
Pipe Insulation	X	X
Low-Flow Showerheads	X	X
Water Heater, Tank Blanket/Insulation	X	X
Water Heater, Timer	X	X
Water Heating, Hot Water Saver	X	X

Measure	Existing	New Construction
Water Heating, Drainwater Heat Recovery		X
Occupancy Sensor	X	X
Outdoor Lighting - Photovoltaic, Installation	X	X
Outdoor Lighting - Photosensor Control	X	X
Outdoor Lighting - Timeclock Installation	X	X
Refrigerator, Remove Second Unit	X	X
Refrigerator, Maintenance	X	X
Freezer, Remove Second Unit	X	X
Freezer, Maintenance	X	X
Home Electronics - Reduce Standby Wattage	X	X
Pool, Pump Timer	X	X
Spa, Pump Timer	X	X
Advanced New Construction Designs		X
ENERGY STAR Homes		X
Home Energy Management System	X	X
Boiler - Pipe Insulation	X	X
Insulation Attic Hatch	X	

Table 5-3 Summary of Commercial Equipment Measures

End Use	Fuel	Technology	Label
Cooling	Electric	Air-Cooled Chiller	1.5 kw/ton, COP 2.3
Cooling	Electric	Air-Cooled Chiller	1.3 kw/ton, COP 2.7
Cooling	Electric	Air-Cooled Chiller	1.26 kw/ton, COP 2.8
Cooling	Electric	Air-Cooled Chiller	1.0 kw/ton, COP 3.5
Cooling	Electric	Air-Cooled Chiller	0.97 kw/ton, COP 3.6
Cooling	Electric	Water-Cooled Chiller	0.75 kw/ton, COP 4.7
Cooling	Electric	Water-Cooled Chiller	0.60 kw/ton, COP 5.9
Cooling	Electric	Water-Cooled Chiller	0.58 kw/ton, COP 6.1
Cooling	Electric	Water-Cooled Chiller	0.55 kw/Ton, COP 6.4
Cooling	Electric	Water-Cooled Chiller	0.51 kw/ton, COP 6.9
Cooling	Electric	Water-Cooled Chiller	0.50 kw/Ton, COP 7.0
Cooling	Electric	Water-Cooled Chiller	0.48 kw/ton, COP 7.3
Cooling	Electric	Roof top AC	EER 9.2
Cooling	Electric	Roof top AC	EER 10.1
Cooling	Electric	Roof top AC	EER 11.2

End Use	Fuel	Technology	Label
Cooling	Electric	Roof top AC	EER 12.0
Cooling	Electric	Roof top AC	Ductless Minisplit
Cooling	Electric	Roof top Heat Pump	EER 9.3
Cooling	Electric	Roof top Heat Pump	EER 10.3
Cooling	Electric	Roof top Heat Pump	EER 11.0
Cooling	Electric	Roof top Heat Pump	EER 11.7
Cooling	Electric	Roof top Heat Pump	EER 12.0
Cooling	Electric	Roof top Heat Pump	Ductless Minisplit
Cooling	Electric	Roof top Heat Pump	Geothermal
Cooling	Electric	Other Cooling	EER 9.8
Cooling	Electric	Other Cooling	EER 10.0
Cooling	Electric	Other Cooling	EER 10.2
Cooling	Electric	Other Cooling	EER 10.4
Cooling	Electric	Other Cooling	EER 10.6
Cooling	Electric	Other Cooling	EER 10.8
Cooling	Electric	Other Cooling	EER 12.0
Space Heating	Electric	Roof top Heat Pump	EER 9.3
Space Heating	Electric	Roof top Heat Pump	EER 10.3
Space Heating	Electric	Roof top Heat Pump	EER 11.0
Space Heating	Electric	Roof top Heat Pump	EER 11.7
Space Heating	Electric	Roof top Heat Pump	EER 12.0
Space Heating	Electric	Roof top Heat Pump	Ductless Minisplit
Space Heating	Electric	Roof top Heat Pump	Geothermal
Space Heating	Electric	Electric Heating	Standard
Ventilation	Electric	Ventilation	Constant Volume
Ventilation	Electric	Ventilation	Constant Volume with ECM
Ventilation	Electric	Ventilation	Variable Air Volume
Ventilation	Electric	Ventilation	Variable Air Volume with ECM
Water Heating	Electric	Water Heating	EF .97
Interior Lighting	Electric	Screw-in	Incandescent
Interior Lighting	Electric	Screw-in	90W Halogen PAR-38
Interior Lighting	Electric	Screw-in	70W HIR PAR-38
Interior Lighting	Electric	Screw-in	LED (2010)
Interior Lighting	Electric	Screw-in	CFL
Interior Lighting	Electric	Screw-in	LED (2020)

End Use	Fuel	Technology	Label
Interior Lighting	Electric	High-Bay Fixtures	Metal Halides (175W)
Interior Lighting	Electric	High-Bay Fixtures	LED (2010)
Interior Lighting	Electric	High-Bay Fixtures	High Pressure Sodium (70W)
Interior Lighting	Electric	High-Bay Fixtures	T5 (28W)
Interior Lighting	Electric	High-Bay Fixtures	T8 (32W)
Interior Lighting	Electric	High-Bay Fixtures	LED (2020)
Interior Lighting	Electric	Linear Fluorescent	T12
Interior Lighting	Electric	Linear Fluorescent	LED (2010)
Interior Lighting	Electric	Linear Fluorescent	T5 (28W)
Interior Lighting	Electric	Linear Fluorescent	T8 (32W)
Interior Lighting	Electric	Linear Fluorescent	Super T8 (25W)
Interior Lighting	Electric	Linear Fluorescent	LED (2020)
Exterior Lighting	Electric	Screw-in	Incandescent
Exterior Lighting	Electric	Screw-in	90W Halogen PAR-38
Exterior Lighting	Electric	Screw-in	70W HIR PAR-38
Exterior Lighting	Electric	Screw-in	LED (2010)
Exterior Lighting	Electric	Screw-in	LED (2020)
Exterior Lighting	Electric	HID	Metal Halides (250W)
Exterior Lighting	Electric	HID	LED (2010)
Exterior Lighting	Electric	HID	High Pressure Sodium (150W)
Exterior Lighting	Electric	HID	LED (2020)
Exterior Lighting	Electric	Linear Fluorescent	T12
Refrigeration	Electric	Walk-in Refrigerator	14600 kWh/yr
Refrigeration	Electric	Walk-in Refrigerator	10800 kWh/yr
Refrigeration	Electric	Walk-in Refrigerator	10000 kWh/yr
Refrigeration	Electric	Walk-in Refrigerator	9000 kWh/yr
Refrigeration	Electric	Reach-in Refrigerator	3100 kWh/yr
Refrigeration	Electric	Reach-in Refrigerator	2500 kWh/yr
Refrigeration	Electric	Reach-in Refrigerator	2400 kWh/yr
Refrigeration	Electric	Reach-in Refrigerator	1500 kWh/yr
Refrigeration	Electric	Glass Door Display	15500 kWh/yr
Refrigeration	Electric	Glass Door Display	14480 kWh/yr
Refrigeration	Electric	Glass Door Display	11700 kWh/yr
Refrigeration	Electric	Glass Door Display	8400 kWh/yr
Refrigeration	Electric	Glass Door Display	6800 kWh/yr

End Use	Fuel	Technology	Label
Refrigeration	Electric	Open Display Case	7000 kWh/yr
Refrigeration	Electric	Open Display Case	6535 kWh/yr
Refrigeration	Electric	Open Display Case	5350 kWh/yr
Refrigeration	Electric	Open Display Case	5300 kWh/yr
Refrigeration	Electric	Open Display Case	4350 kWh/yr
Refrigeration	Electric	Icemaker	7.0 kWh/100 lbs
Refrigeration	Electric	Icemaker	6.3 kWh/100 lbs
Refrigeration	Electric	Icemaker	6.0 kWh/100 lbs
Refrigeration	Electric	Icemaker	5.5 kWh/100 lbs
Refrigeration	Electric	Vending Machine	3400 kWh/year
Refrigeration	Electric	Vending Machine	2400 kWh/year
Refrigeration	Electric	Vending Machine	1700 kWh/year
Food Preparation	Electric	Oven	Standard
Food Preparation	Electric	Oven	Energy Star
Food Preparation	Electric	Fryer	Standard
Food Preparation	Electric	Fryer	Energy Star
Food Preparation	Electric	Dishwasher	Standard
Food Preparation	Electric	Dishwasher	Energy Star
Food Preparation	Electric	Hot Food Container	Standard
Food Preparation	Electric	Hot Food Container	Energy Star
Office Equipment	Electric	Desktop Computer	Standard
Office Equipment	Electric	Desktop Computer	Energy Star
Office Equipment	Electric	Laptop	Standard
Office Equipment	Electric	Laptop	Energy Star
Office Equipment	Electric	Server	Standard
Office Equipment	Electric	Server	Energy Star
Office Equipment	Electric	Monitor	Standard
Office Equipment	Electric	Monitor	Energy Star
Office Equipment	Electric	Printer/Copier/Fax	Standard
Office Equipment	Electric	Printer/Copier/Fax	Energy Star
Office Equipment	Electric	POS Terminal	Standard
Office Equipment	Electric	POS Terminal	Efficient
Miscellaneous	Electric	Non-HVAC Motors	Standard (EPAct)
Miscellaneous	Electric	Non-HVAC Motors	Standard (EPAct 2015)
Miscellaneous	Electric	Non-HVAC Motors	High Efficiency

End Use	Fuel	Technology	Label
Miscellaneous	Electric	Non-HVAC Motors	High Efficiency (2015)
Miscellaneous	Electric	Non-HVAC Motors	Premium (NEMA)
Miscellaneous	Electric	Non-HVAC Motors	Premium (NEMA 2015)
Miscellaneous	Electric	Pool Pump	Standard
Miscellaneous	Electric	Pool Pump	High Efficiency
Miscellaneous	Electric	Pool Pump	Two-Speed
Miscellaneous	Electric	Pool Heater	Standard
Miscellaneous	Electric	Pool Heater	Heat Pump
Miscellaneous	Electric	Pool Heater	Solar
Miscellaneous	Electric	Miscellaneous	Standard
Space Heating	Natural Gas	Furnace	EF .90
Space Heating	Natural Gas	Furnace	EF .91
Space Heating	Natural Gas	Boiler	EF .76
Space Heating	Natural Gas	Boiler	EF .80
Space Heating	Natural Gas	Boiler	EF .82
Space Heating	Natural Gas	Boiler	EF .85
Space Heating	Natural Gas	Boiler	EF .96
Space Heating	Natural Gas	Other Heating	AFUE .74
Space Heating	Natural Gas	Other Heating	AFUE .75
Space Heating	Natural Gas	Other Heating	AFUE .76
Space Heating	Natural Gas	Other Heating	AFUE .77
Space Heating	Natural Gas	Other Heating	AFUE .80
Water Heating	Natural Gas	Water Heating	EF .77
Water Heating	Natural Gas	Water Heating	EF .80
Water Heating	Natural Gas	Water Heating	EF .94
Food Preparation	Natural Gas	Oven	Standard
Food Preparation	Natural Gas	Oven	Energy Star
Food Preparation	Natural Gas	Fryer	Standard
Food Preparation	Natural Gas	Fryer	Energy Star
Food Preparation	Natural Gas	Broiler	Standard
Food Preparation	Natural Gas	Griddle	Standard
Food Preparation	Natural Gas	Griddle	Energy Star
Food Preparation	Natural Gas	Range	Standard
Food Preparation	Natural Gas	Range	High Efficiency
Food Preparation	Natural Gas	Steamer	Standard

End Use	Fuel	Technology	Label
Food Preparation	Natural Gas	Steamer	Energy Star
Miscellaneous	Natural Gas	Pool Heater	EF .78
Miscellaneous	Natural Gas	Pool Heater	EF .82
Miscellaneous	Natural Gas	Pool Heater	EF .90
Miscellaneous	Natural Gas	Pool Heater	EF .95
Miscellaneous	Natural Gas	Miscellaneous	Standard

Table 5-4 Summary of Commercial Non-equipment Measures

Measure	Existing	New Construction
Air Cooled Chiller - Variable Speed Drive	X	X
Air Cooled Chiller - High Efficiency Fans	X	X
Water Cooled Chiller - Variable Speed Drive	X	X
Water Cooled Chiller - High Efficiency Fans	X	X
Water Cooled Chiller - Condenser Water Temperature Reset	X	X
Roof Top AC - Maintenance	X	X
Roof Top Heat Pump - Maintenance	X	X
Gas Furnace - Maintenance	X	X
Gas Boiler - Maintenance	X	X
Gas Boiler - Hot Water Reset	X	X
Gas Boiler - High Efficiency Hot Water Circulation	X	X
Space Heating - Heat Recovery Ventilator	X	X
Economizer - Installation	X	X
Ventilation - Variable Speed Control	X	X
Ventilation - CO2 Controlled	X	X
Ventilation - Exhaust Hood Sensor Control	X	X
Fans - High Efficiency Motors	X	X
Pumps - High Efficiency Motors	X	X
Pumps - Variable Speed Control	X	X
Insulation - Ducting	X	
Insulation - Ceiling	X	
Insulation - Wall Cavity	X	
Ducting - Repair & Sealing	X	X
Cool Roof	X	X
Windows - High Efficiency	X	
Energy Management System	X	X

Measure	Existing	New Construction
Top Daylighting with Skylights		X
HVAC - Occupancy Sensors	X	X
Thermostat - Clock/Programmable	X	X
Interior Lighting - LED Exit Signs	X	X
Interior Lighting - Occupancy Sensors	X	X
Interior Lighting - Task Lighting	X	X
Interior Lighting - Time Clocks and Timers	X	X
Interior Fluorescent - Bi-Level Fixture w/Occupancy Sensor	X	X
Interior Fluorescent - Photocell Controlled Dimming Ballast	X	X
Interior Lighting - Daylighting Controls	X	X
Exterior Fluorescent - Bi-Level Fixture w/Occupancy Sensor	X	X
Exterior Lighting - Daylighting Controls	X	X
Lighting - Retrocommissioning	X	X
Water Heating - Faucet Aerators	X	X
Water Heating - Pipe Insulation	X	X
Water Heating - Hot Water Saver	X	X
Water Heating - High Efficiency Circulation Pumps	X	X
Reach-in Refrigerator - Decommissioning and Recycling	X	X
Refrigeration - Anti-Sweat Heater	X	X
Refrigeration - Door Gasket Replacement	X	X
Open Display Case - Night Covers	X	X
Glass Door Display - LED Lighting	X	X
Vending Machine - Controller	X	X
Office Equipment - Plug Load Occupancy Sensor	X	X
Office Equipment - ENERGY STAR Power Supply	X	X
Non-HVAC Motors - Variable Speed Control	X	X
Pool Pump - Timer	X	X
HVAC Retrocommissioning	X	
HVAC Commissioning		X
Custom Measures	X	X
Advanced New Construction Designs		X

Table 5-5 Summary of Industrial Equipment Measures

End Use	Fuel	Technology	Label
Cooling	Electric	Air-Cooled Chiller	1.5 kw/ton, COP 2.3
Cooling	Electric	Air-Cooled Chiller	1.3 kw/ton, COP 2.7
Cooling	Electric	Air-Cooled Chiller	1.26 kw/ton, COP 2.8
Cooling	Electric	Air-Cooled Chiller	1.0 kw/ton, COP 3.5
Cooling	Electric	Air-Cooled Chiller	0.97 kw/ton, COP 3.6
Cooling	Electric	Water-Cooled Chiller	0.75 kw/ton, COP 4.7
Cooling	Electric	Water-Cooled Chiller	0.60 kw/ton, COP 5.9
Cooling	Electric	Water-Cooled Chiller	0.58 kw/ton, COP 6.1
Cooling	Electric	Water-Cooled Chiller	0.55 kw/Ton, COP 6.4
Cooling	Electric	Water-Cooled Chiller	0.51 kw/ton, COP 6.9
Cooling	Electric	Water-Cooled Chiller	0.50 kw/Ton, COP 7.0
Cooling	Electric	Water-Cooled Chiller	0.48 kw/ton, COP 7.3
Cooling	Electric	Roof top AC	EER 9.2
Cooling	Electric	Roof top AC	EER 10.1
Cooling	Electric	Roof top AC	EER 11.2
Cooling	Electric	Roof top AC	EER 12.0
Cooling	Electric	Roof top AC	Ductless Minisplit
Cooling	Electric	Roof top Heat Pump	EER 9.3
Cooling	Electric	Roof top Heat Pump	EER 10.3
Cooling	Electric	Roof top Heat Pump	EER 11.0
Cooling	Electric	Roof top Heat Pump	EER 11.7
Cooling	Electric	Roof top Heat Pump	EER 12.0
Cooling	Electric	Roof top Heat Pump	Ductless Minisplit
Cooling	Electric	Roof top Heat Pump	Geothermal
Cooling	Electric	Other Cooling	EER 9.8
Cooling	Electric	Other Cooling	EER 10.0
Cooling	Electric	Other Cooling	EER 10.2
Cooling	Electric	Other Cooling	EER 10.4
Cooling	Electric	Other Cooling	EER 10.6
Cooling	Electric	Other Cooling	EER 10.8
Cooling	Electric	Other Cooling	EER 12.0
Space Heating	Electric	Roof top Heat Pump	EER 9.3
Space Heating	Electric	Roof top Heat Pump	EER 10.3

End Use	Fuel	Technology	Label
Space Heating	Electric	Roof top Heat Pump	EER 11.0
Space Heating	Electric	Roof top Heat Pump	EER 11.7
Space Heating	Electric	Roof top Heat Pump	EER 12.0
Space Heating	Electric	Roof top Heat Pump	Ductless Minisplit
Space Heating	Electric	Roof top Heat Pump	Geothermal
Space Heating	Electric	Electric Heating	Standard
Ventilation	Electric	Ventilation	Constant Volume
Ventilation	Electric	Ventilation	Constant Volume with ECM
Ventilation	Electric	Ventilation	Variable Air Volume
Ventilation	Electric	Ventilation	Variable Air Volume with ECM
Water Heating	Electric	Water Heating	EF .97
Interior Lighting	Electric	Screw-in	Incandescent
Interior Lighting	Electric	Screw-in	90W Halogen PAR-38
Interior Lighting	Electric	Screw-in	70W HIR PAR-38
Interior Lighting	Electric	Screw-in	LED (2010)
Interior Lighting	Electric	Screw-in	CFL
Interior Lighting	Electric	Screw-in	LED (2020)
Interior Lighting	Electric	High-Bay Fixtures	Metal Halides (175W)
Interior Lighting	Electric	High-Bay Fixtures	LED (2010)
Interior Lighting	Electric	High-Bay Fixtures	High Pressure Sodium (70W)
Interior Lighting	Electric	High-Bay Fixtures	T5 (28W)
Interior Lighting	Electric	High-Bay Fixtures	T8 (32W)
Interior Lighting	Electric	High-Bay Fixtures	LED (2020)
Interior Lighting	Electric	Linear Fluorescent	T12
Interior Lighting	Electric	Linear Fluorescent	LED (2010)
Interior Lighting	Electric	Linear Fluorescent	T5 (28W)
Interior Lighting	Electric	Linear Fluorescent	T8 (32W)
Interior Lighting	Electric	Linear Fluorescent	Super T8 (25W)
Interior Lighting	Electric	Linear Fluorescent	LED (2020)
Exterior Lighting	Electric	Screw-in	Incandescent
Exterior Lighting	Electric	Screw-in	90W Halogen PAR-38
Exterior Lighting	Electric	Screw-in	70W HIR PAR-38
Exterior Lighting	Electric	Screw-in	LED (2010)
Exterior Lighting	Electric	Screw-in	LED (2020)
Exterior Lighting	Electric	HID	Metal Halides (250W)

End Use	Fuel	Technology	Label
Exterior Lighting	Electric	HID	LED (2010)
Exterior Lighting	Electric	HID	High Pressure Sodium (150W)
Exterior Lighting	Electric	HID	LED (2020)
Exterior Lighting	Electric	Linear Fluorescent	T12
Refrigeration	Electric	Walk-in Refrigerator	14600 kWh/yr
Refrigeration	Electric	Walk-in Refrigerator	10800 kWh/yr
Refrigeration	Electric	Walk-in Refrigerator	10000 kWh/yr
Refrigeration	Electric	Walk-in Refrigerator	9000 kWh/yr
Refrigeration	Electric	Reach-in Refrigerator	3100 kWh/yr
Refrigeration	Electric	Reach-in Refrigerator	2500 kWh/yr
Refrigeration	Electric	Reach-in Refrigerator	2400 kWh/yr
Refrigeration	Electric	Reach-in Refrigerator	1500 kWh/yr
Refrigeration	Electric	Glass Door Display	15500 kWh/yr
Refrigeration	Electric	Glass Door Display	14480 kWh/yr
Refrigeration	Electric	Glass Door Display	11700 kWh/yr
Refrigeration	Electric	Glass Door Display	8400 kWh/yr
Refrigeration	Electric	Glass Door Display	6800 kWh/yr
Refrigeration	Electric	Open Display Case	7000 kWh/yr
Refrigeration	Electric	Open Display Case	6535 kWh/yr
Refrigeration	Electric	Open Display Case	5350 kWh/yr
Refrigeration	Electric	Open Display Case	5300 kWh/yr
Refrigeration	Electric	Open Display Case	4350 kWh/yr
Refrigeration	Electric	Icemaker	7.0 kWh/100 lbs
Refrigeration	Electric	Icemaker	6.3 kWh/100 lbs
Refrigeration	Electric	Icemaker	6.0 kWh/100 lbs
Refrigeration	Electric	Icemaker	5.5 kWh/100 lbs
Refrigeration	Electric	Vending Machine	3400 kWh/year
Refrigeration	Electric	Vending Machine	2400 kWh/year
Refrigeration	Electric	Vending Machine	1700 kWh/year
Food Preparation	Electric	Oven	Standard
Food Preparation	Electric	Oven	Energy Star
Food Preparation	Electric	Fryer	Standard
Food Preparation	Electric	Fryer	Energy Star
Food Preparation	Electric	Dishwasher	Standard
Food Preparation	Electric	Dishwasher	Energy Star

End Use	Fuel	Technology	Label
Food Preparation	Electric	Hot Food Container	Standard
Food Preparation	Electric	Hot Food Container	Energy Star
Office Equipment	Electric	Desktop Computer	Standard
Office Equipment	Electric	Desktop Computer	Energy Star
Office Equipment	Electric	Laptop	Standard
Office Equipment	Electric	Laptop	Energy Star
Office Equipment	Electric	Server	Standard
Office Equipment	Electric	Server	Energy Star
Office Equipment	Electric	Monitor	Standard
Office Equipment	Electric	Monitor	Energy Star
Office Equipment	Electric	Printer/Copier/Fax	Standard
Office Equipment	Electric	Printer/Copier/Fax	Energy Star
Office Equipment	Electric	POS Terminal	Standard
Office Equipment	Electric	POS Terminal	Efficient
Miscellaneous	Electric	Non-HVAC Motors	Standard (EPAct)
Miscellaneous	Electric	Non-HVAC Motors	Standard (EPAct 2015)
Miscellaneous	Electric	Non-HVAC Motors	High Efficiency
Miscellaneous	Electric	Non-HVAC Motors	High Efficiency (2015)
Miscellaneous	Electric	Non-HVAC Motors	Premium (NEMA)
Miscellaneous	Electric	Non-HVAC Motors	Premium (NEMA 2015)
Miscellaneous	Electric	Pool Pump	Standard
Miscellaneous	Electric	Pool Pump	High Efficiency
Miscellaneous	Electric	Pool Pump	Two-Speed
Miscellaneous	Electric	Pool Heater	Standard
Miscellaneous	Electric	Pool Heater	Heat Pump
Miscellaneous	Electric	Pool Heater	Solar
Miscellaneous	Electric	Miscellaneous	Standard

Table 5-6 Summary of Industrial Non-equipment Measures

Measure	Existing	New Construction
Refrigeration - System Controls	X	X
Refrigeration - System Maintenance	X	X
Refrigeration - System Optimization	X	X
Pumps - System Controls	X	X
Pumps - System Optimization	X	X
Pumps - System Maintenance	X	X
Pumps - Variable Frequency Drive	X	X
Pumps - Magnetic Adjustable Speed Drives	X	X
Fans & Blowers - System Controls	X	X
Fans & Blowers - System Optimization	X	X
Fans & Blowers - System Maintenance	X	X
Fans & Blowers - Variable Frequency Drive	X	X
Fans & Blowers - Magnetic Adjustable Speed Drives	X	X
Compressed Air - System Controls	X	X
Compressed Air - System Optimization	X	X
Compressed Air - System Maintenance	X	X
Compressed Air - Compressor Replacement	X	X
Compressed Air - Variable Frequency Drive	X	X
Compressed Air - Magnetic Adjustable Speed Drives	X	X
Conveyors - System Controls	X	X
Conveyors - System Optimization	X	X
Conveyors - System Maintenance	X	X
Conveyors - Variable Frequency Drive	X	X
Conveyors - Magnetic Adjustable Speed Drives	X	X
Other Motors - System Controls	X	X
Other Motors - System Optimization	X	X
Other Motors - System Maintenance	X	X
Other Motors - Variable Frequency Drive	X	X
Other Motors - Magnetic Adjustable Speed Drives	X	X
Roof Top AC - Maintenance	X	X
Evaporative Cooler	X	X
Air Cooled Chiller - Chilled Water Reset	X	X
Air Cooled Chiller - Variable Speed Drive	X	X

Measure	Existing	New Construction
Air Cooled Chiller - High Efficiency Fans	X	X
Air Cooled Chiller - Water Temperature Reset	X	X
Water Cooled Chiller - Chilled Water Reset	X	X
Water Cooled Chiller - Variable Speed Drive	X	X
Water Cooled Chiller - High Efficiency Fans	X	X
Water Cooled Chiller - Water Temperature Reset	X	X
Economizer Installation	X	X
Insulation - Ducting	X	X
Ducting - Repair and Sealing	X	X
Energy Management System	X	X
Exhaust Hoods - Cooking, Sensor Control	X	X
Fans, Energy-Efficient Motors	X	X
Fans, Variable Speed Control	X	X
Thermostat, Clock/Programmable	X	X
Variable Air-Volume Systems	X	X
Ventilation, CO2-Controlled	X	X
Insulation - Ceiling	X	X
Insulation - Wall Cavity	X	X
Roofs - High Reflectivity	X	X
Windows - High Efficiency	X	X
Daylighting Controls - Outdoors	X	X
Daylighting Controls - Photocell-Controlled Dimming Ballasts	X	X
Fluorescent - Delamp and Install Reflectors	X	X
Fluorescent, Bi-Level Fixture w/ Integrated Occupancy Sensor	X	X
Interior Lighting - LED Exit Lighting	X	X
Interior Lighting - Occupancy Sensors	X	X
Interior Lighting - Task Lighting	X	X
Interior Lighting - Time Clocks and Timers	X	X
Lighting Retrocommissioning	X	X
Lighting Commissioning		X
Transformer, High Efficiency	X	X
Comprehensive Retrocommissioning	X	
Comprehensive Commissioning		X
Gas Furnace - Maintenance	X	X
Space Heating - Heat Recovery Ventilator	X	X

Measure	Existing	New Construction
Boiler - Maintenance	X	X
Boiler - Hot Water Reset	X	X
Boiler - High Efficiency Hot Water Circulation	X	X

Results of the Economic Screen

Table 5-7 summarizes the number of equipment and non-equipment measures evaluated for each segment within each sector.

Table 5-7 Number of Measures Evaluated

	Residential	Commercial	Industrial	Total Number of Measures
Equipment Measures Evaluated	162	161	130	**453**
Non-Equipment Measures Evaluated	39	57	71	**167**
Total Measures Evaluated	**201**	**218**	**201**	**620**

Appendix B gives results for the economic screening process by segment, vintage, end use and measure for the residential sector. Appendices C and D shows the equivalent information for the commercial and industrial sectors, respectively.

CHAPTER | 6

ENERGY EFFICIENCY POTENTIAL FOR ELECTRICITY

Across all sectors, achievable potential for electricity savings in 2031/32 is 1,321 GWh. This represents 5.6% of the baseline forecast. Table 6-1 presents the levels of electric energy-efficiency potential across sectors as well as the baseline forecasts of energy consumption. Key findings related to market, economic and technical potentials are summarized below.

- **Market potential** is 1,869 GWh in 2017/18, which represents 8.7% of the baseline forecast. By 2031/32, the cumulative savings are 5,709 GWh, or 22.3%, of the baseline forecast.
- **Economic potential**, which reflects the savings when all cost-effective measures are taken, is 2,862 GWh in 2017/18. This represents 13.4% of the baseline energy forecast. By 2031/32, economic potential reaches 7,234 GWh, 28.3% of the baseline energy forecast.
- **Technical potential**, which reflects the adoption of all energy efficiency measures regardless of cost-effectiveness, is a theoretical upper bound on savings. In 2017/18, energy savings are 3,506 GWh, or 16.4% of the baseline energy forecast. By 2031/32, technical potential reaches 8,379 GWh, 32.8% of the baseline energy forecast.

Table 6-1 Summary of Energy Efficiency Potential for Electricity

	2012/13	2017/18	2022/23	2027/28	2031/32
Baseline Forecast (GWh)	**20,580**	**20,706**	**21,589**	**22,757**	**23,790**
Energy Savings (Cumulative GWh)					
Achievable Potential	48	325	787	1,145	1,321
Market Potential	92	1,079	2,159	2,915	3,229
Economic Potential	686	2,260	3,841	4,836	5,240
Technical Potential	853	2,961	4,911	6,158	6,691
Energy Savings (% of Baseline)					
Achievable Potential	0.2%	1.6%	3.6%	5.0%	5.6%
Market Potential	0.4%	5.2%	10.0%	12.8%	13.6%
Economic Potential	3.3%	10.9%	17.8%	21.3%	22.0%
Technical Potential	4.1%	14.3%	22.7%	27.1%	28.1%

Figure 6-1 summarizes the energy-efficiency savings for the different levels of potential relative to the baseline forecast. Table 6-1 displays the energy-efficiency forecasts. By 2031/32, Achievable potential offsets about one third of the growth in electricity use.

Figure 6-1 Summary of Potential Energy Savings for Electricity

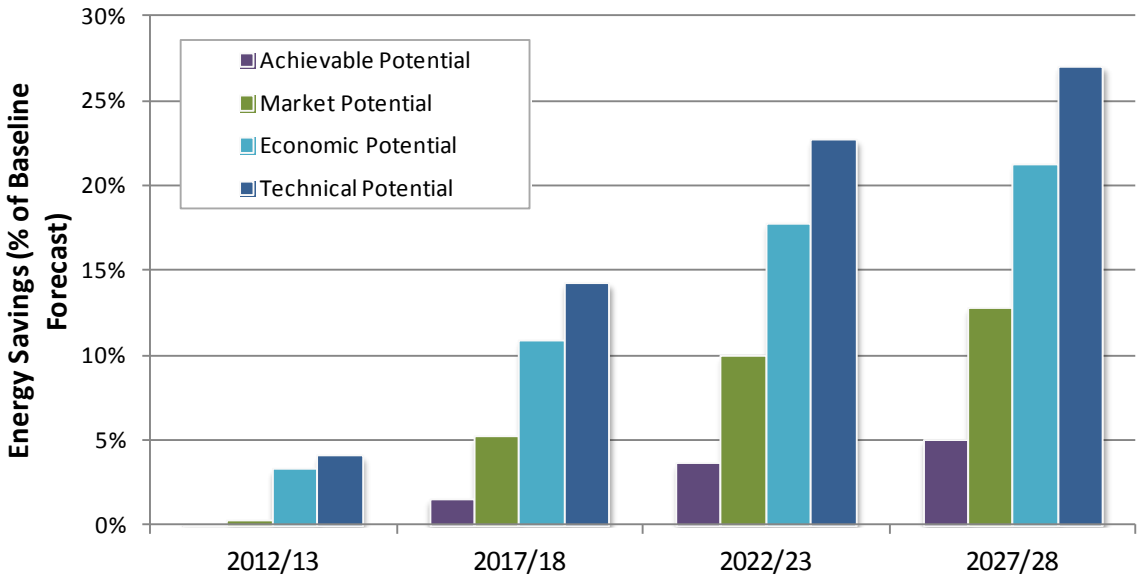


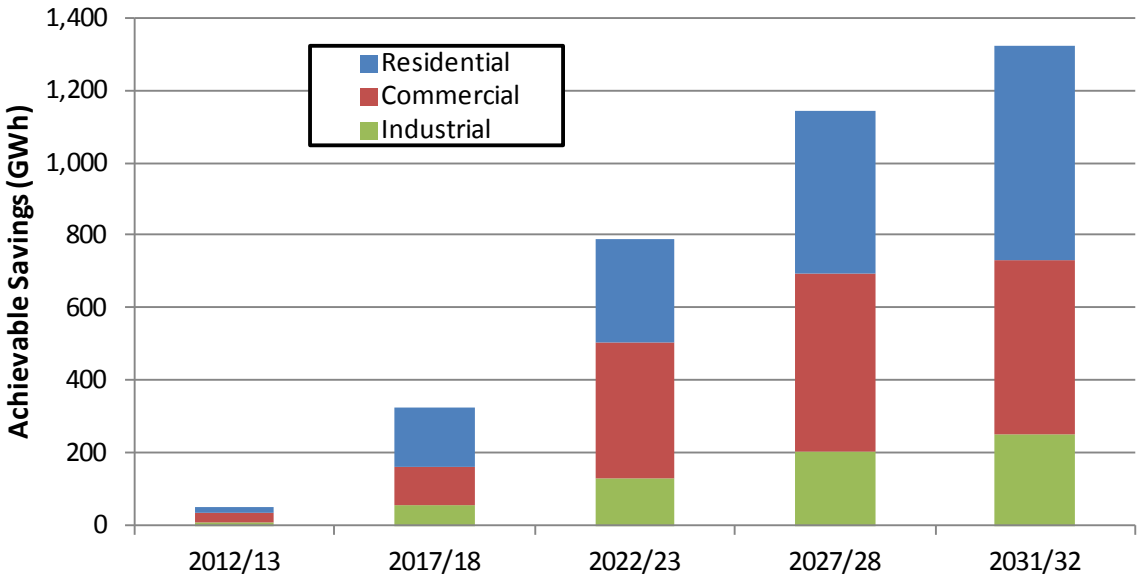
Table 6-2 and Figure 6-2 summarizes achievable potential by sector. The residential sector accounts for the largest portion of the savings, followed by the commercial and then the industrial sectors.

The remainder of this chapter presents potential estimates for each sector.

Table 6-2 Achievable Potential for Electricity by Sector (GWh)

	2012/13	2017/18	2022/23	2027/28	2031/32
Residential	16	166	285	448	589
Commercial	25	105	370	491	482
Industrial	7	54	132	206	250
Total	**48**	**325**	**787**	**1,145**	**1,321**

Figure 6-2 Achievable Potential for Electricity by Sector



Residential Sector

Table 6-3 presents estimates for the four types of potential. Figure 6-3 depicts the potential energy savings estimates graphically.

- **Achievable potential** projects 166 GWh of energy savings in 2017/18, 2% of the baseline forecast. This increases to 589 GWh, 7% of the baseline forecast, in 2031/32.
- **Market potential** is 457 GWh in 2017/18, which represents 6% of the baseline forecast. By 2031/32, the cumulative energy savings are 1,342 GWh, or 15% of the baseline forecast.
- **Economic potential** is 916 GWh in 2017/18. This represents 13% of the baseline energy forecast. By 2031/32, economic potential reaches 2,201 GWh, 25% of the baseline energy forecast.
- **Technical potential.** In 2017/18, energy savings are 1,425 GWh, or 20% of the baseline energy forecast. By 2031/32, technical potential reaches 3,146 GWh, 36% of the baseline energy forecast.

Figure 6-4 shows the forecasts under the four levels of potential along with the baseline forecast.

Table 6-3 Energy Efficiency Potential for the Residential Sector for Electricity

	2012/13	2017/18	2022/23	2027/28	2031/32
Baseline Forecast (GWh)	**6,955**	**7,168**	**7,592**	**8,215**	**8,331**
Energy Savings (GWh)					
Achievable Potential	16	166	285	448	589
Market Potential	24	457	763	1,114	1,342
Economic Potential	207	916	1,410	1,902	2,201
Technical Potential	293	1,425	2,162	2,802	3,146
Energy Savings (% of Baseline)					
Achievable Potential	0.2%	2.3%	3.7%	5.5%	6.7%
Market Potential	0.3%	6.4%	10.0%	13.6%	15.2%
Economic Potential	3.0%	12.8%	18.6%	23.1%	24.9%
Technical Potential	4.2%	19.9%	28.5%	34.1%	35.6%

Figure 6-3 Residential Energy Efficiency Potential Savings for Electricity

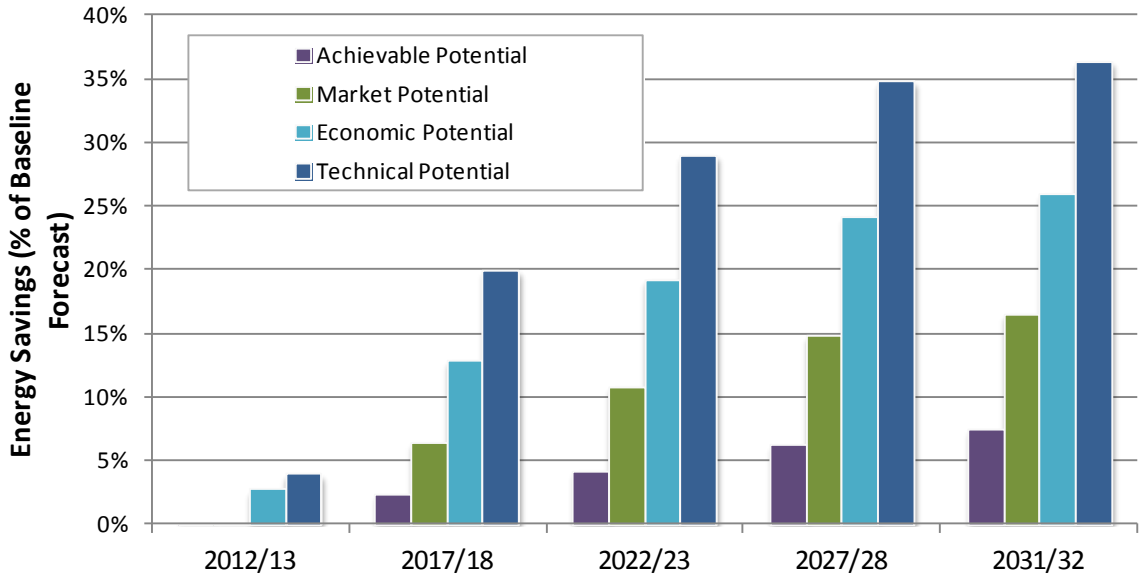
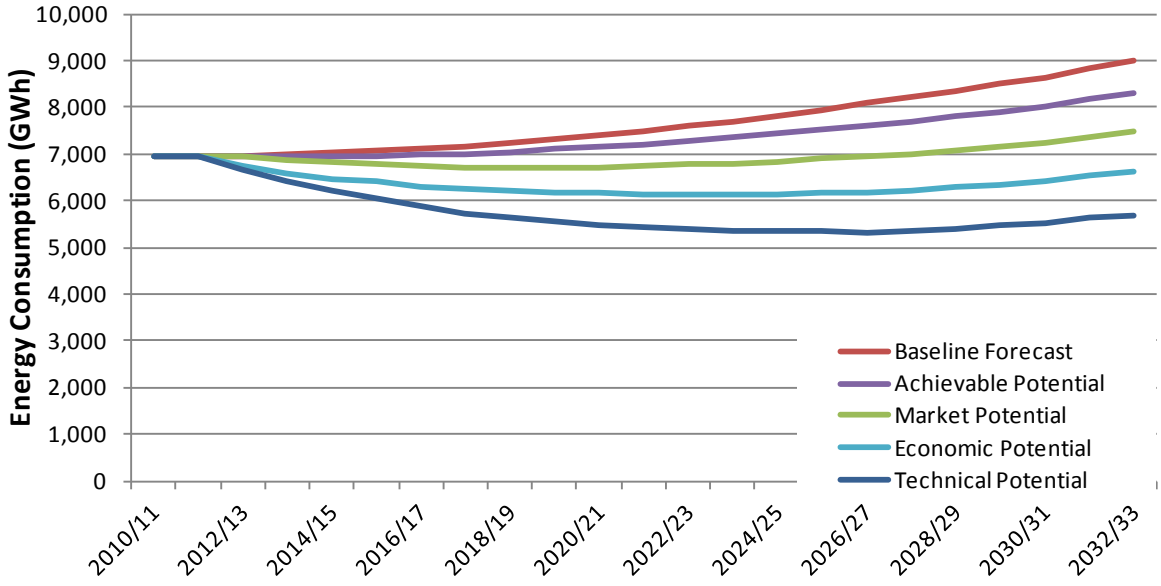


Figure 6-4 Residential Energy Efficiency Potential Forecast



Residential Potential by End Use, Technology, and Measure Type

Table 6-4 provides estimates of savings for each end use and type of potential. Focusing first on technical and economic potential, there are significant savings that are both possible and economic in numerous end uses:

- **Heating** offers the highest technical potential, which reflects the across the board-installation of EER 30 geothermal heat pumps, increased insulation in the ceiling and wall cavities, and widespread installation of home energy management systems. However, these measures are not always cost effective and therefore economic potential drops by almost half.
- **Water heating** offers the second-highest technical potential, which reflects across-the-board installation of low-flow showerheads, hot water savers, drainwater heat recovery, and faucet aerators. While these are often cost effective, these measures do not pass the economic screen for all segments or years during the forecast. This results in economic potential that is about 10% less than technical potential.
- **Appliances** also have significant technical potential savings. This reflects both the replacement of failed white-goods appliances with the highest-efficiency option and removal of second refrigerators in appliance recycling programs.
- **Interior lighting** offers the largest potential savings in the earlier half of the time horizon. The lighting standard begins its phase-in starting in 2012, which coincides with the availability in the market place of advanced incandescent lamps that meet the minimum efficacy standard. The baseline forecast assumes that people will install both advanced incandescent and CFLs in screw-in lighting applications, and that traditional incandescent will still make up one fifth of the market for specialty lighting and other applications that are exempt from the lighting standard. For technical potential, LED lamps are the most efficient option, starting in 2012. However, LED lamps do not pass the economic screen until 2020/21, so CFLs dominate economic-potential savings for most of the earlier years.

Table 6-4 Residential Electricity Savings by End Use and Potential Type (GWh)

End Use	Case	2017/18	2022/23	2027/28	2031/32
Cooling	Achievable Potential	9	17	23	28
	Market Potential	19	36	49	58
	Economic Potential	25	45	62	73
	Technical Potential	59	96	121	133
Heating	Achievable Potential	79	150	235	305
	Market Potential	196	384	581	727
	Economic Potential	337	672	1,007	1,215
	Technical Potential	631	1,170	1,658	1,879
HVAC Other	Achievable Potential	1	3	6	9
	Market Potential	7	15	25	29
	Economic Potential	12	22	31	35
	Technical Potential	15	25	35	40
Water Heating	Achievable Potential	14	31	44	54
	Market Potential	31	74	103	125
	Economic Potential	114	181	219	252
	Technical Potential	128	201	244	279
Interior Lighting	Achievable Potential	24	24	54	79
	Market Potential	68	59	115	131
	Economic Potential	123	89	127	136
	Technical Potential	172	105	112	137
Exterior Lighting	Achievable Potential	2	2	9	15
	Market Potential	5	6	20	27
	Economic Potential	34	21	29	31
	Technical Potential	45	23	25	30
Appliances	Achievable Potential	29	34	32	33
	Market Potential	64	80	76	77
	Economic Potential	157	198	190	192
	Technical Potential	212	275	267	270
Electronics	Achievable Potential	8	19	35	51
	Market Potential	60	91	114	131
	Economic Potential	73	115	143	164
	Technical Potential	79	123	152	173
Miscellaneous	Achievable Potential	1	5	11	16
	Market Potential	7	16	29	38
	Economic Potential	40	68	92	103
	Technical Potential	85	143	186	205
Total	**Achievable Potential**	**166**	**284**	**448**	**589**
	Market Potential	**456**	**762**	**1,114**	**1,341**
	Economic Potential	**916**	**1,410**	**1,901**	**2,201**
	Technical Potential	**1,425**	**2,162**	**2,802**	**3,146**

As described in Chapter 2, using our LoadMAP model, we develop separate estimates of potential for equipment and non-equipment measures. Table 6-5 presents Achievable potential cumulative savings for the top measures in 2031/32.

Table 6-5 Residential Achievable Potential Top Measures in 2031/32

End Use	Measure	Cumulative Savings (GWh) in 2031/32			
		Economic	% of Total for Economic	Market	Achievable
Heating	Furnace	539.2	24.5%	167.0	45.9
Heating	Insulation, Ceiling	164.6	7.5%	183.5	62.9
Heating	Insulation, Wall Cavity	162.7	7.4%	38.2	19.8
Appliances	Refrigerator, Remove Second Unit	146.7	6.7%	58.7	25.1
Interior Lighting	Screw-in	124.9	5.7%	121.6	72.6
Heating	ENERGY STAR Homes	108.9	4.9%	103.3	53.2
Heating	Home Energy Management System	84.7	3.8%	59.8	28.4
Water Heating	Low-Flow Showerheads	83.8	3.8%	63.2	27.3
Water Heating	Water Heating, Hot Water Saver	74.6	3.4%	11.7	5.4
Heating	Insulation - Infiltration Control	65.5	3.0%	83.5	41.2
Electronics	TVs	65.0	3.0%	38.8	13.2
Electronics	Set-top Boxes/DVR	61.6	2.8%	61.6	24.4
Appliances	Freezer, Remove Second Unit	45.3	2.1%	17.9	7.6
Water Heating	Water Heating, Drainwater Heat Recovery	34.0	1.5%	16.6	7.7
Heating	Windows, ENERGY STAR	32.2	1.5%	43.8	26.2
Exterior Lighting	Screw-in	29.8	1.4%	26.4	14.6
Heating	Advanced New Construction Designs	27.7	1.3%	16.8	10.0
Electronics	Personal Computers	26.2	1.2%	22.4	9.9
HVAC Other	Electronic Air Cleaner	22.3	1.0%	18.9	5.3
Water Heating	Faucet Aerators	21.6	1.0%	19.0	8.5
Total - Top 20 Measures for Economic Potential		**1,921.4**	**87.3%**	**1,172.9**	**509.3**

Commercial Sector Potential

The baseline forecast for the commercial sector only grows slightly, which reflects the sluggish near-term economy and forthcoming codes and standards. Nevertheless, the opportunity for energy-efficiency savings is still significant for the commercial sector.

- **Achievable potential** projects 105 GWh of energy savings in 2017/18 and 482 GWh in 2031/32. This corresponds to 2% of the baseline forecast in 2017/18 and 9% in 2031/32.
- **Market potential** is 340 GWh in 2017/18, which represents 6% of the baseline forecast. By 2031/32, the cumulative energy savings are 1,065 GWh, 19% of the baseline forecast.
- **Economic potential** is 866 GWh in 2017/18. This represents 16% of the baseline energy forecast. By 2031/32, economic potential reaches 1,766 GWh, or 31% of the baseline energy forecast.
- **Technical potential**. In 2017/18, energy savings are 1,023 GWh, or 19% of the baseline energy forecast. By 2031/32, technical potential reaches 2,082 GWh, 37% of the baseline energy forecast.

Table 6-6 and Figure 6-5 present the savings associated with each level of potential. Figure 6-6 shows the commercial sector forecasts for the various levels of potential.

Table 6-6 Energy Efficiency Potential for the Commercial Sector

	2012/13	2017/18	2022/23	2027/28	2031/32
Baseline Forecast (GWh)	5,646	5,361	5,441	5,527	5,655
Savings (GWh)					
Achievable Potential	25	105	370	491	482
Market Potential	40	340	858	1,065	1,065
Economic Potential	407	866	1,541	1,768	1,766
Technical Potential	476	1,023	1,769	2,041	2,082
Savings (% of Baseline)					
Achievable Potential	0.4%	2.0%	6.8%	8.9%	8.5%
Market Potential	0.7%	6.3%	15.8%	19.3%	18.8%
Economic Potential	7.2%	16.2%	28.3%	32.0%	31.2%
Technical Potential	8.4%	19.1%	32.5%	36.9%	36.8%

Figure 6-5 Commercial Energy Efficiency Potential Savings

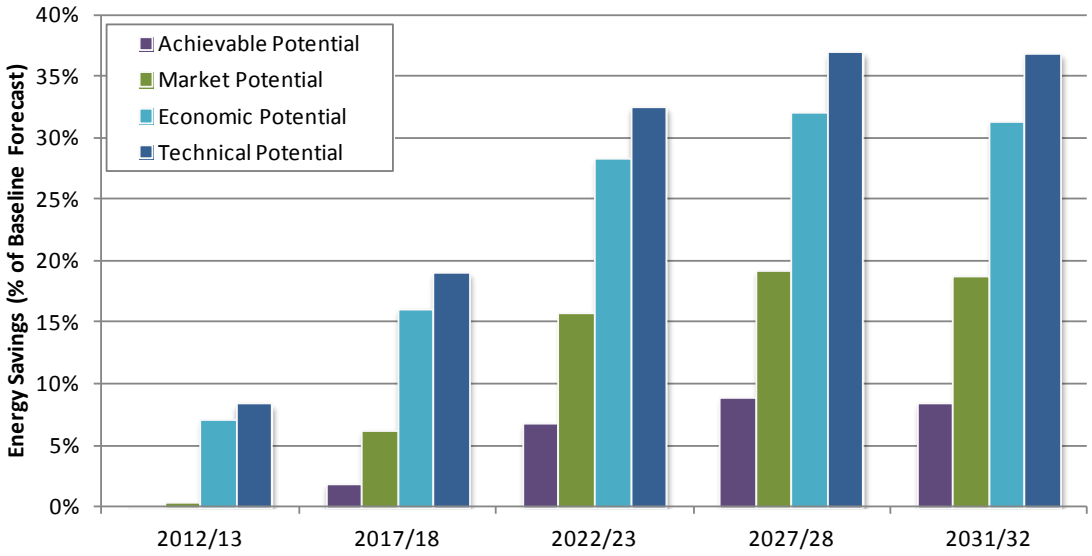
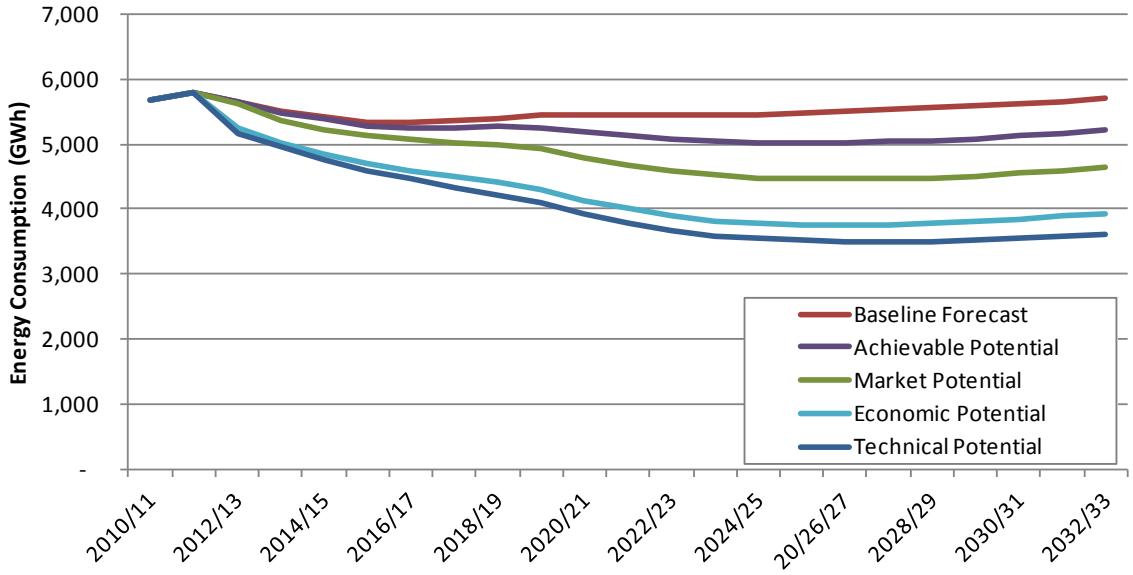


Figure 6-6 Commercial Energy Efficiency Potential Forecast



Commercial Potential by End Use, Technology, and Measure Type

Table 6-7 presents the commercial sector savings by end use and potential type. The end uses with the highest technical and economic potential are:

- Lighting, primarily interior lighting, has the highest technical potential at 657 GWh in 2031/32 as a result of LED lighting that is now commercially available for screw-in applications. Moreover, most of the lighting equipment and measures are cost-effective resulting in economic potential of 575 GWh, which is 88% of technical potential.
- Cooling has the second highest savings for technical potential at 634 GWh in 2031/32. These savings result from installation of high-efficiency equipment, numerous thermal shell measures, HVAC control strategies, and retrocommissioning. Many of these measures are cost-effective, resulting in economic potential savings of 513 GWh in 2015, or 81% of technical potential savings.

Ventilation, space heating, office equipment, water heating, and refrigeration also have significant savings in terms of technical and economic potential.

Table 6-7 focuses on achievable potential savings. Not surprisingly, interior lighting delivers the highest achievable savings throughout the study period. In 2031/32, cooling is second.

Table 6-7 Commercial Achievable Potential by End Use and Potential Type (GWh)

End Use	Case	2017/18	2022/23	2027/28	2031/32
Cooling	Achievable Potential	27	69	94	109
	Market Potential	83	190	248	281
	Economic Potential	238	392	471	513
	Technical Potential	281	467	574	634
Space Heating	Achievable Potential	6	13	23	31
	Market Potential	22	45	66	81
	Economic Potential	48	84	113	129
	Technical Potential	66	119	174	210
Ventilation	Achievable Potential	17	44	60	68
	Market Potential	49	112	143	160
	Economic Potential	159	251	296	323
	Technical Potential	167	265	314	344
Water Heating	Achievable Potential	1	3	3	3
	Market Potential	4	8	8	9
	Economic Potential	9	12	11	11
	Technical Potential	11	15	14	13
Interior Lighting	Achievable Potential	39	194	242	201
	Market Potential	111	366	424	354
	Economic Potential	277	588	616	525
	Technical Potential	351	676	692	606
Exterior Lighting	Achievable Potential	5	18	22	17
	Market Potential	16	38	46	34
	Economic Potential	26	55	63	45
	Technical Potential	30	63	70	51
Refrigeration	Achievable Potential	5	11	15	16
	Market Potential	11	23	29	32
	Economic Potential	22	37	45	47
	Technical Potential	23	39	48	50
Food Preparation	Achievable Potential	1	2	2	2
	Market Potential	3	6	7	6
	Economic Potential	8	11	10	9
	Technical Potential	8	11	10	9
Office Equipment	Achievable Potential	4	13	24	28
	Market Potential	38	54	70	81
	Economic Potential	64	67	83	95
	Technical Potential	69	71	85	97
Miscellaneous	Achievable Potential	2	7	10	11
	Market Potential	8	22	31	35
	Economic Potential	28	57	73	80
	Technical Potential	28	57	73	80
Total	**Achievable Potential**	**108**	**374**	**495**	**487**
	Market Potential	**345**	**865**	**1,072**	**1,072**
	Economic Potential	**877**	**1,554**	**1,781**	**1,778**
	Technical Potential	**1,034**	**1,783**	**2,054**	**2,094**

Table 6-8 presents the top measures in 2031/32. The greatest economic savings come from:

- Ventilation – variable speed control with 215 GWh, although only 31 GWh is achievable.
- Linear fluorescent lighting – replacing T-12 with T-18 lamps provides 150 GWh in economic savings, with 83 GWh considered achievable.
- Occupancy sensors – the economic potential for occupancy sensors on the interior lighting is 100 GWh, although only 19 GWh is considered achievable.

Table 6-8 Commercial Achievable Potential – Top Measures (GWh)

End Use	Measure	Cumulative Savings (GWh) in 2031/32			
		Economic	% of Total for Economic	Market	Achiev-able
Ventilation	Ventilation - Variable Speed Control	215	12%	78	31
Interior Lighting	Linear Fluorescent	150	8%	128	83
Interior Lighting	Interior Lighting - Occupancy Sensors	100	6%	41	19
Cooling	Economizer - Installation	98	6%	37	15
Ventilation	Ventilation	69	4%	52	26
Office Equipment	Office Equipment - ENERGY STAR Power Supply	65	4%	55	19
Interior Lighting	Screw-in	54	3%	42	22
Interior Lighting	Interior Lighting - Daylighting Controls	50	3%	33	24
Cooling	Water Cooled Chiller - Variable Speed Drive	49	3%	11	4
Cooling	Water-Cooled Chiller	45	3%	9	4
Cooling	Windows - High Efficiency	44	2%	44	14
Interior Lighting	Top Daylighting with Skylights	41	2%	17	8
Space Heating	Electric Heating	41	2%	38	26
Miscellaneous	Pumps - Variable Speed Control	40	2%	26	7
Interior Lighting	Interior Fluorescent - Photocell Controlled Dimming Ballast	40	2%	18	9
Exterior Lighting	HID	38	2%	29	15
Cooling	Custom Measures	37	2%	36	12
Cooling	Roof Top AC - Maintenance	36	2%	22	13
Cooling	HVAC Retrocommissioning	35	2%	23	5
Space Heating	Insulation - Ceiling	34	2%	16	4
Miscellaneous	Non-HVAC Motors - Variable Speed Control	32	2%	4	2
Cooling	Insulation - Wall Cavity	30	2%	14	3
Interior Lighting	Custom Measures	29	2%	29	10
Office Equipment	Office Equipment - Plug Load Occupancy Sensor	26	1%	22	8
Interior Lighting	Interior Lighting - Task Lighting	26	1%	16	10
Space Heating	Insulation - Wall Cavity	25	1%	10	2
Cooling	Air Cooled Chiller - Variable Speed Drive	23	1%	5	2
Cooling	Air-Cooled Chiller	23	1%	9	4
Cooling	Insulation - Ceiling	19	1%	9	3
Ventilation	Ventilation - CO2 Controlled	17	1%	4	2
Total - Top 30 Measures for Economic Potential		**1,530**	**86.5%**	**878**	**406**

Industrial Sector Potential

The industrial sector, at 7,978 GWh in 2010/11, accounts for over one-third of total electricity sales. Chemical products and primary metals are the two largest industries, accounting for 61% of total industrial sales in 2010/11.

Most of the equipment replacement opportunities are in the machine drive (motors) end use, but potential savings are diminishing due to the National Electrical Manufacturer's Association (NEMA) standards, which now make premium efficiency motors the baseline efficiency level. As a result, potential savings are only available from upgrading to still more efficient levels. Furthermore, due to the site-specific nature of many industrial sector process energy efficiency opportunities, savings potential resulting from these customized approaches should be characterized individually. To understand these opportunities in more depth, it would be appropriate to carry out site-specific engineering assessments for each customer, though we would recommend that such assessments be limited to only the very largest customers.

Throughout the study period, Economic potential is about 85%–90% of Technical potential, indicating that most of the measures evaluated are cost-effective. In 2031/32, Achievable potential is 250 GWh or 2.7% of the baseline industrial forecast. Table 6-9, Figure 6-7 and Figure 6-8 present the savings for the various types of potential considered in this study.

Table 6-9 Energy Efficiency Potential for the Industrial Sector

	2012/13	2017/18	2022/23	2027/28	2031/32
Baseline Forecast (GWh)	**7,978**	**8,177**	**8,556**	**9,016**	**9,304**
Energy Savings (GWh)					
Achievable Potential	7	54	132	206	250
Market Potential	28	282	538	736	822
Economic Potential	73	478	890	1,166	1,274
Technical Potential	84	513	981	1,315	1,463
Energy Savings (% of Baseline)					
Achievable Potential	0.1%	0.7%	1.5%	2.3%	2.7%
Market Potential	0.4%	3.5%	6.3%	8.2%	8.8%
Economic Potential	0.9%	5.8%	10.4%	12.9%	13.7%
Technical Potential	1.1%	6.3%	11.5%	14.6%	15.7%

Figure 6-7 Industrial Energy Efficiency Potential Savings

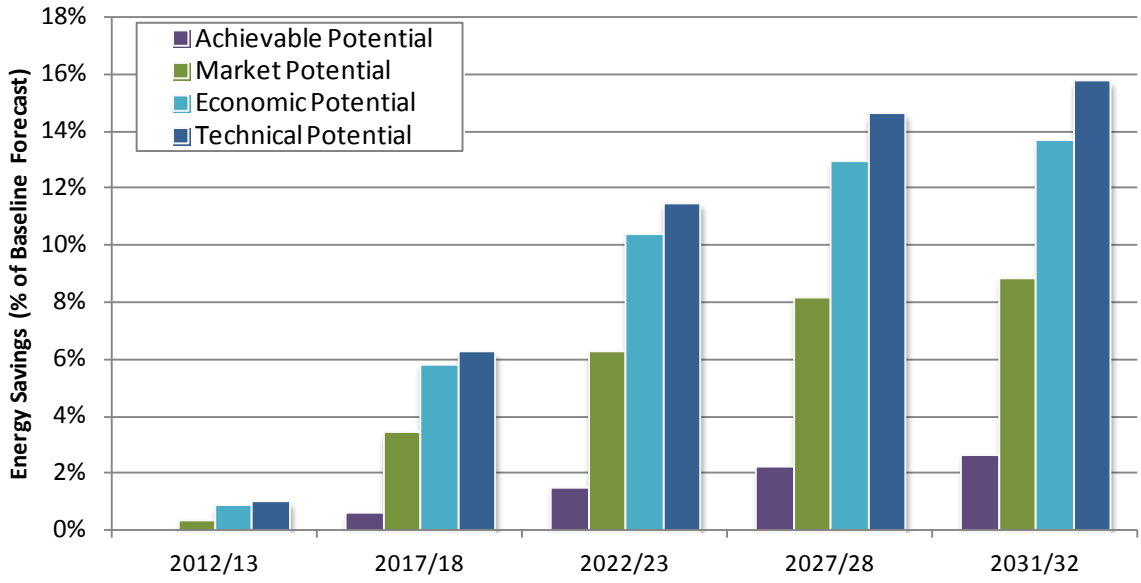
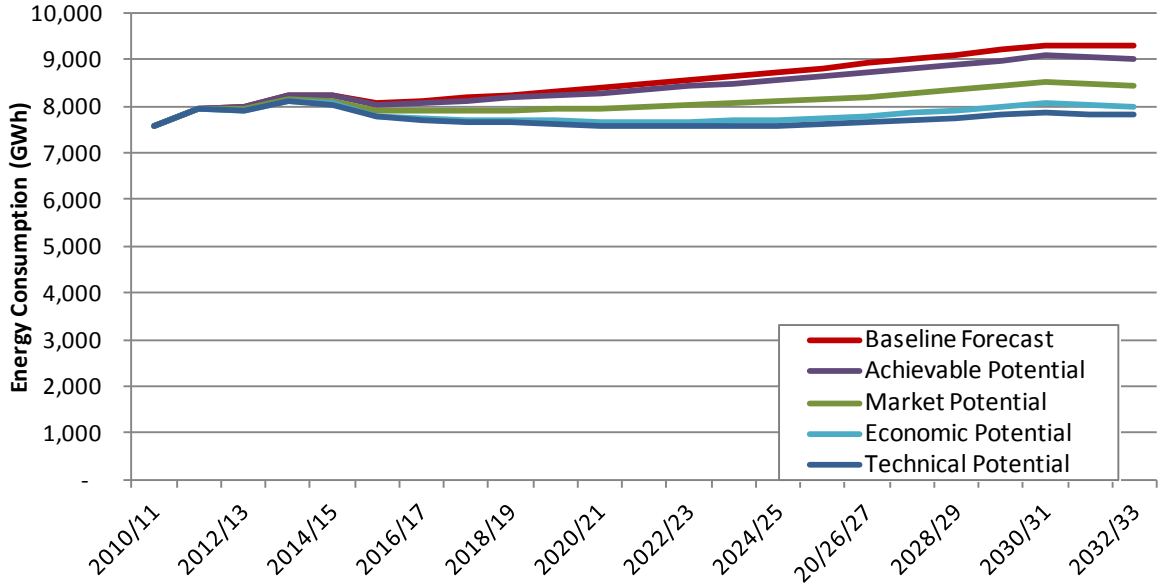


Figure 6-8 Industrial Energy Efficiency Potential Forecast



Industrial Potential by End Use

Table 6-10 presents the industrial savings by end use and type of potential. As mentioned above, the various motors offer the greatest opportunity for energy savings across the range of potential.

Table 6-10 Industrial Potential by End Use and Potential Type (GWh)

End Use	Level of Potential	2017/18	2022/23	2027/28	2031/32
Cooling	Achievable Potential	6	17	24	28
	Market Potential	28	67	93	106
	Economic Potential	47	86	118	132
	Technical Potential	60	112	158	178
Space Heating	Achievable Potential	2	6	9	10
	Market Potential	10	24	33	36
	Economic Potential	16	29	39	43
	Technical Potential	16	30	39	43
Ventilation	Achievable Potential	1	4	5	5
	Market Potential	6	15	18	19
	Economic Potential	11	19	21	21
	Technical Potential	12	20	21	22
Interior Lighting	Achievable Potential	8	32	70	98
	Market Potential	34	113	210	240
	Economic Potential	54	134	238	258
	Technical Potential	57	140	246	269
Exterior Lighting	Achievable Potential	1	6	12	15
	Market Potential	3	21	37	39
	Economic Potential	5	25	41	42
	Technical Potential	5	25	41	42
Pumps	Achievable Potential	10	18	24	28
	Market Potential	60	86	106	125
	Economic Potential	76	129	160	183
	Technical Potential	81	154	187	205
Fans & Blowers	Achievable Potential	10	18	21	23
	Market Potential	49	70	79	86
	Economic Potential	62	106	123	132
	Technical Potential	64	110	131	144
Compressed Air	Achievable Potential	4	6	8	9
	Market Potential	23	31	37	43
	Economic Potential	30	55	68	75
	Technical Potential	32	59	78	91
Conveyors	Achievable Potential	2	4	6	6
	Market Potential	11	19	21	22
	Economic Potential	32	56	64	68
	Technical Potential	33	58	69	75
Other Motors	Achievable Potential	10	21	27	28
	Market Potential	58	91	101	106
	Economic Potential	147	251	296	320
	Technical Potential	151	260	313	346
Process Heating	Achievable Potential	1	1	1	1
	Market Potential	4	5	6	7
	Economic Potential	82	149	183	203

End Use	Level of Potential	2017/18	2022/23	2027/28	2031/32
	Technical Potential	87	158	200	229
Process Cooling & Refrigeration	Achievable Potential	-	-	-	-
	Market Potential	-	-	-	-
	Economic Potential	-	-	-	-
	Technical Potential	3	12	31	48
Total	**Achievable Potential**	**54**	**133**	**207**	**251**
	Market Potential	**286**	**542**	**741**	**829**
	Economic Potential	**560**	**1,039**	**1,350**	**1,477**
	Technical Potential	**600**	**1,139**	**1,516**	**1,692**

Table 6-11 Industrial Achievable Potential – Top Measures (GWh)

End Use	Measure	Cumulative Savings (GWh) in 2031/32			
		Economic	% of Total for Economic	Market	Achievable
Interior Lighting	Linear Fluorescent	206	16%	194	81
Other Motors	Other Motors	117	9%	100	27
Other Motors	Other Motors - Magnetic Adjustable Speed Drives	81	6%	-	-
Other Motors	Other Motors - Variable Frequency Drive	81	6%	4	1
Pumps	Pumps	59	5%	50	14
Cooling	Energy Management System	53	4%	47	13
Fans & Blowers	Fans & Blowers	49	4%	41	11
Pumps	Pumps - Variable Frequency Drive	44	3%	39	7
Process Heating	Process Heating	42	3%	2	0
Exterior Lighting	HID	37	3%	33	12
Fans & Blowers	Fans & Blowers - Variable Frequency Drive	34	3%	30	9
Fans & Blowers	Fans & Blowers - Magnetic Adjustable Speed Drives	33	3%	2	1
Other Motors	Other Motors - System Controls	27	2%	1	0
Miscellaneous	Miscellaneous	27	2%	23	4
Compressed Air	Compressed Air - Magnetic Adjustable Speed Drives	26	2%	-	-
Electro-Chemical Processes	Electro-Chemical Processes	25	2%	22	6
Heating	Insulation - Wall Cavity	23	2%	20	4
Pumps	Pumps - System Controls	20	2%	18	3
Ventilation	Ventilation	18	1%	15	4
Conveyors	Conveyors - Variable Frequency Drive	18	1%	-	-
Total - Top 20 Measures for Economic Potential		**1,019**	**80%**	**640**	**198**

CHAPTER | 7

ENERGY EFFICIENCY POTENTIAL FOR NATURAL GAS

Achievable potential for natural gas in 2031/32 is 106 MMm^3 in 2031/32. This represents 7% of the baseline forecast. Table 7-1 presents the levels of natural gas energy-efficiency potential across sectors along with the baseline forecast. Key findings related to market, economic and technical potentials are summarized below.

- **Market potential** is 295 MMm^3 in 2031/32, which represents 19% of the baseline forecast.
- **Economic potential** is 530 MMm^3 in 2031/32. This represents 34% of the baseline energy forecast.
- **Technical potential.** In 2031/32, technical potential reaches 589 MMm^3 38% of the baseline energy forecast.

Table 7-1 Summary of Energy Efficiency Potential

	2012/13	2017/18	2022/23	2027/28	2031/32
Baseline Forecast (MMm^3)	**1,567**	**1,598**	**1,616**	**1,631**	**1,651**
Natural Gas Savings (MMm^3)					
Achievable Potential	6	34	66	91	106
Market Potential	15	97	190	256	295
Economic Potential	59	202	352	464	530
Technical Potential	71	226	390	516	589
Natural Gas Savings (% of Baseline)					
Achievable Potential	0.4%	2.2%	4.2%	5.8%	6.8%
Market Potential	1.0%	6.2%	12.1%	16.3%	18.8%
Economic Potential	3.8%	12.9%	22.4%	29.6%	33.8%
Technical Potential	4.5%	14.4%	24.9%	32.9%	37.6%

Figure 7-1 displays the energy-efficiency forecasts.

Figure 7-1 Summary of Achievable Potential Energy Savings

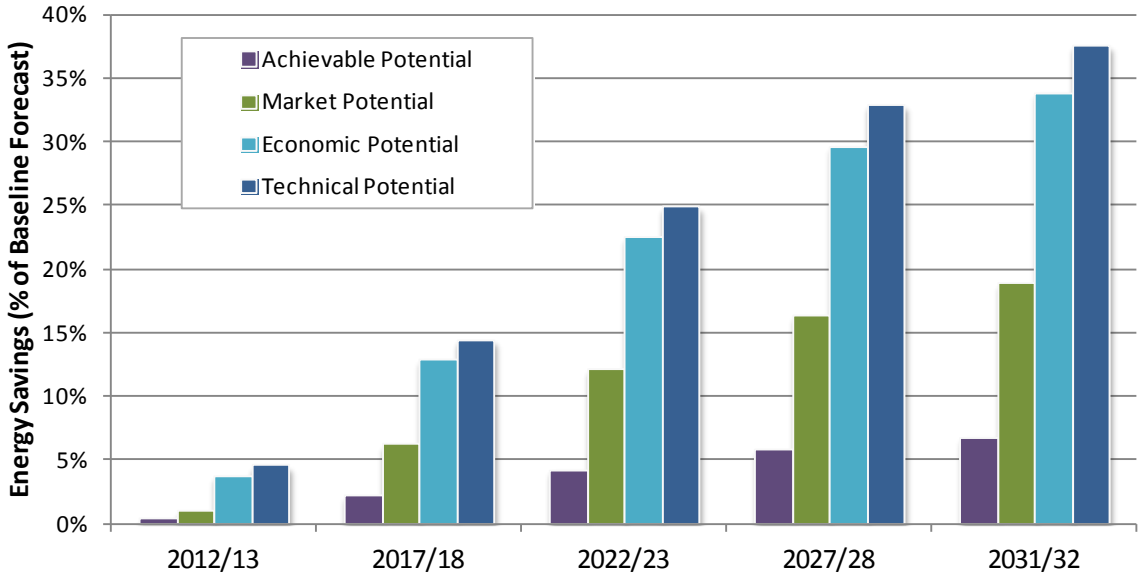
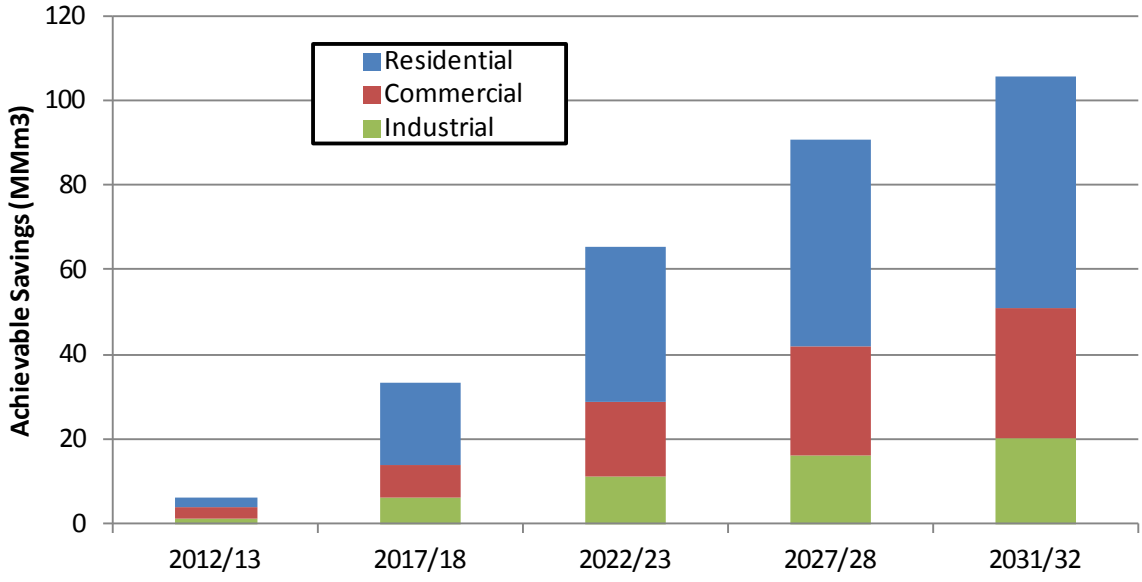


Table 7-2 summarizes the range of achievable potential by sector. The residential sector accounts for the largest portion of the savings, followed by the commercial sector.

Table 7-2 Achievable Energy-efficiency Potential by Sector (MMm^3)

	2012/13	2017/18	2022/23	2027/28	2031/32
Achievable Savings (GWh)					
Residential	2	20	37	49	55
Commercial	3	8	18	26	31
Industrial	1	6	11	16	20
Total	**6**	**33**	**65**	**91**	**106**

Figure 7-2 Achievable Potential for Natural Gas by Sector



Residential Sector

Table 7-3 presents estimates for the four types of potential. Figure 7-4 depicts the potential energy savings estimates graphically.

- **Achievable potential** projects 84 MMm^3 of energy savings in 2017/18, 15.2% of the baseline forecast. This increases to 238 MMm^3, 43.1% of the baseline forecast, in 2031/32.
- **Market potential** is 87 MMm^3 in 2017/18, which represents 15.7% of the baseline forecast. By 2031/32, the cumulative energy savings are 245 MMm^3, 44.4% of the baseline forecast.
- **Economic potential** is 90 MMm^3 in 2017/18. This represents 16.4% of the baseline energy forecast. By 2031/32, economic potential reaches 253 MMm^3, 46% of the baseline energy forecast.
- **Technical potential**. In 2017/18, energy savings are 109 MMm^3, or 19.7% of the baseline energy forecast. By 2031/32, technical potential reaches 286 $MMm^{3,}$ 51.9% of the baseline energy forecast.

Table 7-3 Electricity Energy Efficiency Potential for the Residential Sector

	2012/13	2017/18	2022/23	2027/28	2031/32
Baseline Forecast (MMm^3)	**567**	**578**	**587**	**593**	**598**
Natural Gas Savings (MMm^3)					
Achievable Potential	2	20	37	49	55
Market Potential	5	44	86	113	126
Economic Potential	17	71	130	171	188
Technical Potential	21	85	152	202	222
Natural Gas Savings (% of Baseline)					
Achievable Potential	0.3%	3.4%	6.2%	8.2%	9.2%
Market Potential	0.8%	7.6%	14.6%	19.1%	21.1%
Economic Potential	3.0%	12.3%	22.2%	28.9%	31.5%
Technical Potential	3.7%	14.7%	25.9%	34.0%	37.0%

Figure 7-3 Residential Energy Efficiency Potential Savings

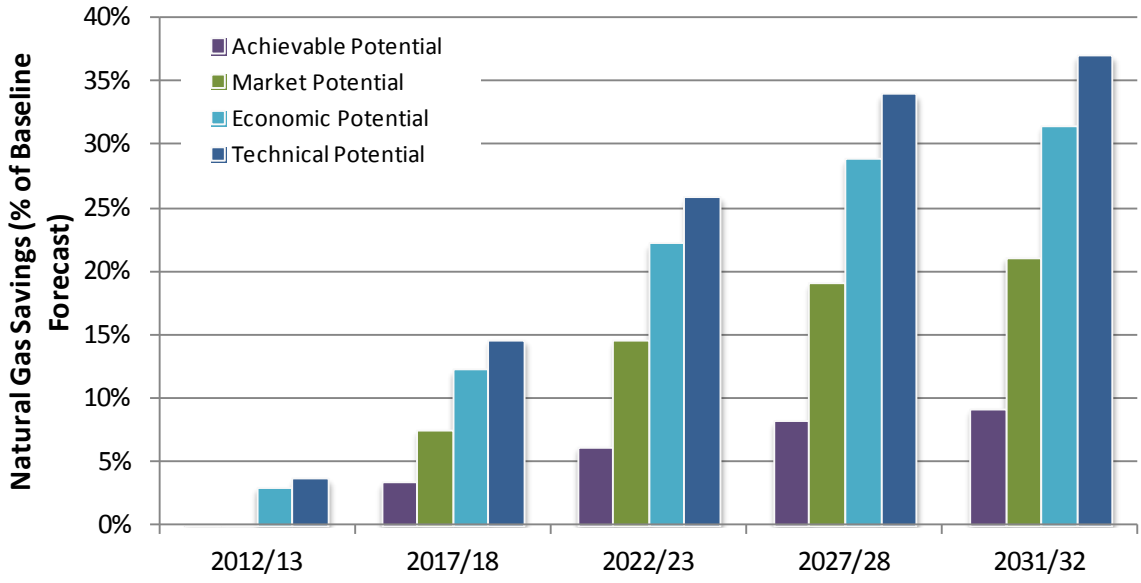
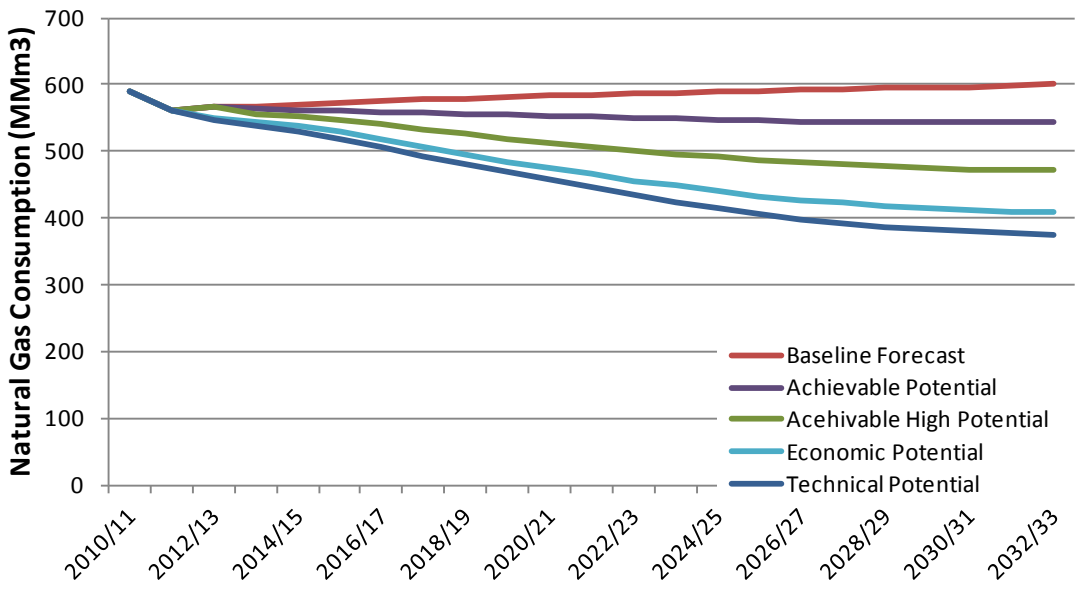


Figure 7-4 Residential Energy Efficiency Potential Forecast



Residential Potential by End Use, Technology, and Measure Type

Table 7-4 provides estimates of savings for each end use and type of potential. Focusing first on technical and economic potential, there are significant savings that are both possible and economic in numerous end uses:

- **Space Heating** offers the highest technical potential, which reflects the across the board-installation of EF 0.95 boilers, AFUE 96% furnaces, and several building shell measures. However, these high efficiency boilers and furnaces do not become cost-effective, using the study's assumptions of equipment cost and avoided cost, during the forecast period. Also included in space heating potentials are non-equipment measures such as increased insulation in wall cavities, ceilings, and infiltration control.
- **Water heating** also has significant technical potential savings. This reflects across the board installation of condensing gas storage water heaters, as well as non-equipment measures such as low-flow showerheads and faucet aerators.

Table 7-4 Residential Savings by End Use and Potential Type (MMm^3)

End Use	Case	2017/18	2022/23	2027/28	2031/32
Heating	Achievable Potential	18	33	45	51
	Market Potential	40	78	105	118
	Economic Potential	56	111	152	170
	Technical Potential	63	122	169	190
Water Heating	Achievable Potential	2	3	3	3
	Market Potential	4	7	8	8
	Economic Potential	15	19	19	18
	Technical Potential	21	28	30	28
Appliances	Achievable Potential	0	0	0	0
	Market Potential	0	0	0	0
	Economic Potential	0	0	0	0
	Technical Potential	0	0	0	0
Miscellaneous	Achievable Potential	0	0	0	0
	Market Potential	0	1	1	1
	Economic Potential	0	1	1	1
	Technical Potential	1	2	3	3
Total	**Achievable Potential**	**20**	**37**	**49**	**55**
	Market Potential	**44**	**86**	**113**	**126**
	Economic Potential	**71**	**131**	**172**	**189**
	Technical Potential	**84**	**152**	**201**	**221**

As described in Chapter 2, using our LoadMAP model, we develop separate estimates of potential for equipment and non-equipment measures. Table 7-5 presents the top measures from both equipment replacement and non-equipment measures.

Table 7-5 Residential Achievable Potential Top Measures

End Use	Measure	Cumulative Savings (MMm^3) in 2031/32			
		Economic	% of Total for Economic	Market	Achievable
Heating	Insulation, Wall Cavity	66	35%	13	7
Heating	Insulation, Ceiling	40	21%	39	13
Heating	Insulation - Infiltration Control	17	9%	19	9
Heating	Home Energy Management System	13	7%	10	5
Heating	Furnace - Gas, Maintenance	10	5%	11	5
Heating	Windows, ENERGY STAR	8	4%	10	6
Water Heating	Low-Flow Showerheads	7	4%	5	2
Water Heating	Water Heating, Hot Water Saver	6	3%	1	0
Heating	Furnace	6	3%	6	2
Heating	ENERGY STAR Homes	5	3%	5	3
Heating	Insulation, Foundation	3	1%	2	1
Heating	Doors, Storm and Thermal	3	1%	3	2
Water Heating	Water Heater, Timer	3	1%	0	0
Water Heating	Faucet Aerators	2	1%	1	1
Miscellaneous	Pool Heater	1	1%	1	0
Heating	Insulation Attic Hatch	1	0%	1	0
Water Heating	Water Heater	0	0%	0	0
Heating	Advanced New Construction Designs	0	0%	0	0
Total of Top Measures		**189**	**100%**	**126**	**55**

Commercial Sector Potential

The baseline forecast for the commercial sector has moderate growth and the opportunity for energy-efficiency savings is still significant for the commercial sector.

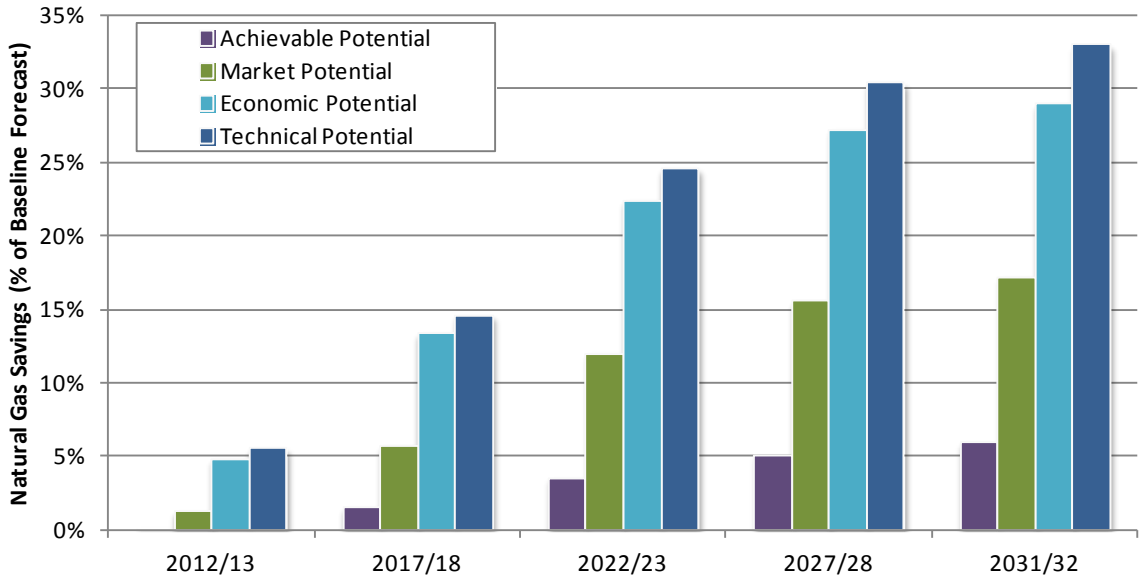
- **Achievable potential** projects 31 MMm^3 2031/32. This corresponds to 6% of the baseline forecast in 2031/32.
- **Market potential** in 2031/32 shows 89 MMm^3, 17% of the baseline forecast.
- **Economic potential** is 150 MMm^3 in 2031/32, 29% of the baseline energy forecast.
- **Technical potential**. In 2031/32, technical potential reaches 171 MMm^3, 33% of the baseline energy forecast.

Table 7-6 and Figure 7-5 present the savings associated with each level of potential.

Table 7-6 Energy Efficiency Potential for the Commercial Sector

	2012/13	2017/18	2022/23	2027/28	2031/32
Baseline Forecast (MMm^3)	**484**	**497**	**502**	**506**	**517**
Natural Gas Savings (MMm^3)					
Achievable Potential	3	8	18	26	31
Market Potential	6	29	60	79	89
Economic Potential	24	67	113	138	150
Technical Potential	27	73	124	154	171
Natural Gas Savings (% of Baseline)					
Achievable Potential	0.6%	1.5%	3.6%	5.1%	6.0%
Market Potential	1.3%	5.7%	12.0%	15.6%	17.2%
Economic Potential	4.9%	13.4%	22.5%	27.3%	29.0%
Technical Potential	5.6%	14.7%	24.7%	30.5%	33.1%

Figure 7-5 Commercial Energy Efficiency Potential Savings



Commercial Potential by End Use, Technology, and Measure Type

Table 7-7 presents the commercial sector savings by end use and potential type. Space heating savings are highest as a result of higher efficiency furnaces and boilers, as well as several shell measures contribute to the savings. Other savings come from food preparation and water heating. Table 7-8 shows the top measures.

Table 7-7 Commercial Potential by End Use and Potential Type (MMm³)

	Case	2017/18	2022/23	2027/28	2031/32
Space Heating	Achievable Potential	7	16	24	29
	Market Potential	25	55	73	83
	Economic Potential	58	102	129	143
	Technical Potential	64	112	145	163
Water Heating	Achievable Potential	1	1	1	1
	Market Potential	2	3	2	2
	Economic Potential	6	6	4	3
	Technical Potential	6	7	4	3
Food Preparation	Achievable Potential	0	1	1	1
	Market Potential	1	3	3	3
	Economic Potential	3	5	5	5
	Technical Potential	3	5	5	5
Total	**Achievable Potential**	**8**	**18**	**26**	**31**
	Market Potential	**29**	**60**	**79**	**89**
	Economic Potential	**67**	**113**	**138**	**150**
	Technical Potential	**73**	**124**	**154**	**171**

Table 7-8 Commercial Achievable Savings for Top Measures (MMm³)

End Use	Measure	Cumulative Savings (MMm³) in 2031/32			
		Economic	% of Total for Economic	Market	Achievable
Space Heating	Insulation - Ceiling	33	22.2%	16	4
Space Heating	Insulation - Wall Cavity	23	15.3%	10	2
Space Heating	HVAC Retrocommissioning	21	13.8%	14	3
Space Heating	Gas Boiler - Hot Water Reset	16	10.7%	7	3
Space Heating	Custom Measures	12	7.7%	11	4
Space Heating	Gas Boiler - Maintenance	8	5.3%	5	3
Space Heating	Windows - High Efficiency	6	4.3%	6	2
Space Heating	Thermostat - Clock/Programmable	6	3.9%	5	2
Space Heating	Boiler	5	3.2%	4	4
Space Heating	Space Heating - Heat Recovery Ventilator	5	3.0%	3	1
Space Heating	Energy Management System	4	2.8%	3	1
Space Heating	Furnace	3	1.8%	0	0
Food Preparation	Steamer	2	1.5%	2	1
Space Heating	Gas Furnace - Maintenance	2	1.1%	1	1
Water Heating	Water Heating - Hot Water Saver	1	1.0%	1	0
Water Heating	Water Heating - Faucet Aerators	1	0.8%	1	0
Food Preparation	Fryer	1	0.6%	1	0
Food Preparation	Oven	1	0.5%	0	0
Food Preparation	Range	1	0.4%	0	0
Food Preparation	Griddle	0	0.2%	0	0
Total - Top 20 Measures for Economic Potential		**150**	**100%**	**89**	**31**

Industrial Sector Potential

The industrial sector, at 509 MMm^3 in 2010/11, accounts for over one-third of total natural gas sales. Chemical products and primary metals are the two largest industries, accounting for 39% of total industrial sales in 2010/11. The heating and process heating end uses offer the greatest opportunity for energy savings across the range of potential. Process heat recovery has the largest technical potential for the industrial sector with about 8.5 MMm^3 per year. Significant savings can also be achieved through hot water boiler/steam conversion and HVAC heat recovery.

Most of the efficiency opportunities are in the heating or process heating end uses. Throughout the study period, Economic potential is about 80%–90% of Technical potential, indicating that most of the measures evaluated are cost-effective. In 2017/18, Achievable potential is 6 MMm^3 or 1.1% of the baseline industrial forecast. By 2031/32, it increases to 20 MMm^3, or 3.7% of the baseline forecast. Table 7-9, Figure 7-6 and Figure 7-7 present the savings for the various types of potential considered in this study.

Table 7-9 Energy Efficiency Potential for the Industrial Sector

	2012/13	2017/18	2022/23	2027/28	2031/32
Baseline Forecast (10^6 m3)	517	522	527	532	536
Natural Gas Savings (10^6 m3)					
Achievable Potential	1	6	11	16	20
Market Potential	4	24	44	64	80
Economic Potential	18	64	109	155	192
Technical Potential	23	68	114	160	196
Natural Gas Savings (% of Baseline)					
Achievable Potential	0.2%	1.1%	2.1%	3.0%	3.7%
Market Potential	0.8%	4.6%	8.4%	12.0%	14.9%
Economic Potential	3.5%	12.2%	20.8%	29.2%	35.7%
Technical Potential	4.4%	13.1%	21.6%	30.0%	36.6%

Figure 7-6 Industrial Energy Efficiency Potential Savings

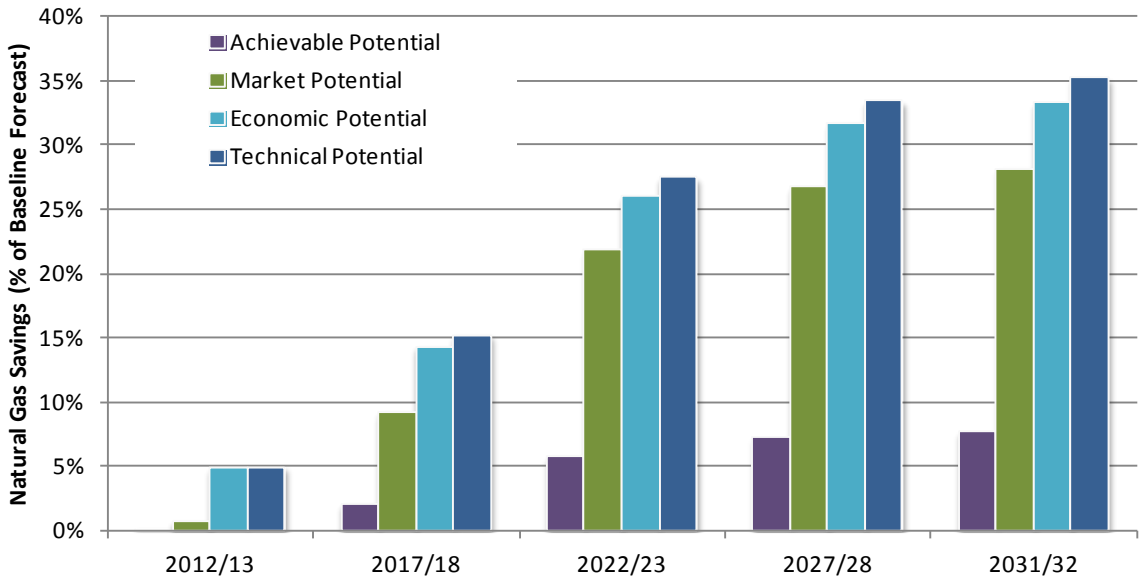
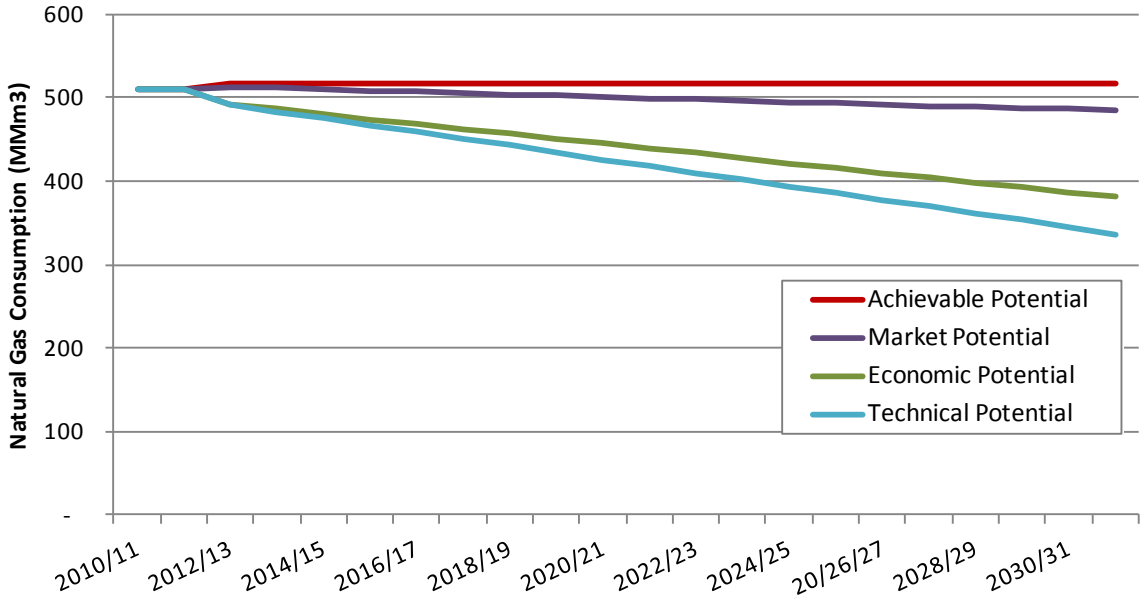


Figure 7-7 Industrial Energy Efficiency Potential Forecast



About EnerNOC Utility Solutions Consulting

EnerNOC Utility Solutions Consulting is part of EnerNOC Utility Solutions group, which provides a comprehensive suite of demand-side management (DSM) services to utilities and grid operators worldwide. Hundreds of utilities have leveraged our technology, our people, and our proven processes to make their energy efficiency (EE) and demand response (DR) initiatives a success. Utilities trust EnerNOC to work with them at every stage of the DSM program lifecycle – assessing market potential, designing effective programs, implementing those programs, and measuring program results.

EnerNOC Utility Solutions delivers value to our utility clients through two separate practice areas – Program Implementation and EnerNOC Utility Solutions Consulting.

- Our Program Implementation team leverages EnerNOC's deep "behind-the-meter expertise" and world-class technology platform to help utilities create and manage DR and EE programs that deliver reliable and cost-effective energy savings. We focus exclusively on the commercial and industrial (C&I) customer segments, with a track record of successful partnerships that spans more than a decade. Through a focus on high quality, measurable savings, EnerNOC has successfully delivered hundreds of thousands of MWh of energy efficiency for our utility clients, and we have thousands of MW of demand response capacity under management.
- The EnerNOC Utility Solutions Consulting team provides expertise and analysis to support a broad range of utility DSM activities, including: potential assessments; end-use forecasts; integrated resource planning; EE, DR, and smart grid pilot and program design and administration; load research; technology assessments and demonstrations; evaluation, measurement and verification; and regulatory support.

The EnerNOC Utility Solutions Consulting team has decades of combined experience in the utility DSM industry. The staff is comprised of professional electrical, mechanical, chemical, civil, industrial, and environmental engineers as well as economists, business planners, project managers, market researchers, load research professionals, and statisticians. Utilities view our experts as trusted advisors, and we work together collaboratively to make any DSM initiative a success.

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REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Page No.: 9

PREAMBLE: "Social Acceptability Two public opinion polls conducted by Ipsos and the Innovative Research Group in April 2011 were used to gauge Canadian public opinion regarding six methods of producing electricity (solar, wind, hydro-electric, natural gas, nuclear and coal). Polling results plus inferences drawn from the data are used to populate this characteristic. The degree of respondent support corresponds to the level of acceptance of individual resource technologies."

QUESTION:

Please provide the results from the opinion poll including the questions and responses and any analysis performed by Ipsos and Innovative Research Group.

RESPONSE:

Please see Manitoba Hydro's response to CAC/MH I-084.

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.3.6; Page No.: 60

PREAMBLE: The terms of reference provide for a consideration of the macro environmental impact of the Plan as compared to alternatives. The term macro-environmental is defined in PUB Order 92/13.

According to Manitoba Hydro:

"Overall, while there would be some adverse effects, for the most part they would be mitigated and limited in duration. Some concerns would no doubt remain, but again, the KCNs support and participation in the project suggest that local adverse effects would be offset by the positive impacts and expected benefits." [Emphasis added]

In the FLCN (2012) Environment Evaluation Report (EIS), as cited in the preamble to CEC Round 1 – 0035 (EIS), it is stated:

"Our people have been greatly impacted by fifty years of hydro development and **the Keeyask project will further disturb, fragment, and destroy lands and waters that have been and continue to be used by our Members**. FLCN views all hydro projects, including Keeyask, as one continuous staged process of development with impacts that are cumulative and long-term." [Emphasis added]

In the YFFN (2012) Report "Our Voices", it is stated that:

"When our members talk about Keeyask, we don't see this project as any different from the changes brought by the overall Churchill/Nelson/Burntwood hydro-electric program. **We see Keeyask as a continuation of a larger development project. We are not confident that the exact effects of a new development can be predicted, but we expect Keeyask to add to the changes that we have already experienced – to further destabilize our increasingly compromised environment**". [Emphasis added]

YFFN (2012) Report "Our Voices" Chapter 13, pgs 60 – 61, 13.3.6"

QUESTION:

Does Manitoba Hydro agree with the bolded conclusion of the FLCN? If not, please explain your answer.

RESPONSE:

Manitoba Hydro confirms that the above statements have been correctly quoted from the sources selected in the above information request. The referenced quotes describe concerns raised by members of Fox Lake First Nation, which has committed to participate in the Keeyask project.

The Keeyask Partnership made the decision to adopt a two-track process in which there would be a Keeyask Cree Nations' evaluation process and a government regulatory process. The first was conducted by each of the KCNs for their internal purposes; the second was prepared to comply with federal and provincial regulators processes. The KCNs' evaluations – which were submitted as part of the Keeyask Environmental Impact Statement – are based on their own worldview, values and experiences, while the regulatory evaluation is consistent with the regulatory framework and practices under the *Canadian Environmental Assessment Act* and *The Environment Act* (Manitoba). These processes are explained in the Partnership's EIS and in a number of IRs, such as CEC Rd. 1 CAC-0057, which noted that, "Given the differing worldviews, there are naturally some cases where the conclusions reached to date by these two evaluation processes are different…In such cases, the Partnership has developed monitoring programs that respond to the concerns raised through both worldviews."

Manitoba Hydro and the partner communities understand the importance of continuing programs and dialogue to address these types of concerns. The successful conclusion of the Joint Keeyask Development Agreement and each community's Adverse Effects Agreement was an important milestone in the development of the Keeyask Project, but all parties recognize

that the partnership and project require on-going attention. Having voted to join the partnership and support the project, the communities have continued to be actively engaged in the employment and business opportunities, the environmental assessment and other related activities.

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Section: 13.3.6; Page No.: 60

PREAMBLE: The terms of reference provide for a consideration of the macro environmental impact of the Plan as compared to alternatives. The term macro-environmental is defined in PUB Order 92/13.

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"Overall, while there would be some adverse effects, for the most part they would be mitigated and limited in duration. Some concerns would no doubt remain, but again, the KCNs support and participation in the project suggest that local adverse effects would be offset by the positive impacts and expected benefits." [Emphasis added]

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"Our people have been greatly impacted by fifty years of hydro development and **the Keeyask project will further disturb, fragment, and destroy lands and waters that have been and continue to be used by our Members**. FLCN views all hydro projects, including Keeyask, as one continuous staged process of development with impacts that are cumulative and long-term." [Emphasis added]

In the YFFN (2012) Report "Our Voices", it is stated that:

"When our members talk about Keeyask, we don't see this project as any different from the changes brought by the overall Churchill/Nelson/Burntwood hydro-electric program. **We see Keeyask as a continuation of a larger development project. We are not confident that the exact effects of a new development can be predicted, but we expect Keeyask to add to the changes that we have already experienced – to further destabilize our increasingly compromised environment**". [Emphasis added]

YFFN (2012) Report "Our Voices" Chapter 13, pgs 60 – 61, 13.3.6

QUESTION:

Does Manitoba Hydro agree with the bolded conclusion of the YFFN? If not, please explain your answer.

RESPONSE:

Manitoba Hydro confirms that the above statements have been correctly quoted from the sources selected in the above information request. The referenced quotes describe concerns raised by members of York Factory First Nation, which has committed to participate in the Keeyask project.

The Keeyask Partnership made the decision to adopt a two-track process in which there would be a Keeyask Cree Nations' evaluation process and a government regulatory process. The first was conducted by each of the KCNs for their internal purposes; the second was prepared to comply with federal and provincial regulators processes. The KCNs' evaluations – which were submitted as part of the Keeyask Environmental Impact Statement – are based on their own worldview, values and experiences, while the regulatory evaluation is consistent with the regulatory framework and practices under the *Canadian Environmental Assessment Act* and *The Environment Act* (Manitoba). These processes are explained in the Partnership's EIS and in a number of IRs, such as CEC Rd. 1 CAC-0057, which noted that, "Given the differing worldviews, there are naturally some cases where the conclusions reached to date by these two evaluation processes are different…In such cases, the Partnership has developed monitoring programs that respond to the concerns raised through both worldviews."

Manitoba Hydro and the partner communities understand the importance of continuing programs and dialogue to address these types of concerns. The successful conclusion of the Joint Keeyask Development Agreement and each community's Adverse Effects Agreement was an important milestone in the development of the Keeyask Project, but all parties recognize

that the partnership and project require on-going attention. Having voted to join the partnership and support the project, the communities have continued to be actively engaged in the employment and business opportunities, the environmental assessment and other related activities.

REFERENCE: Chapter 7: Screening of Manitoba Resource Options; Section: Table 7.1; Page No.: 3

QUESTION:

Under the column "social acceptability", please provide the basis for concluding "some concern" relating to wind and geo-thermal given that no opinion polling was conducted.

RESPONSE:

As no polling information regarding "In-Lake Wind" or "Enhanced Geothermal System" was present in the polling information used for Table 7.1, Manitoba Hydro was unable to categorize either utility scale resource technology in the "Screened Out" or the "Minimal Concern or Positive" categories. As a result, the social acceptability characteristics for these two technologies were placed in the neutral "Some Concern" classification.

REFERENCE: Chapter 13: Integrated Comparisons of Development Plans - Multiple Account Analysis; Page No.: 59-60

PREAMBLE: The filing suggests that although there are expected to be some adverse impacts on domestic resource use and commercial trapping due to disturbance to fish and wildlife resources and habitat, these impacts are limited and are offset by the provision of alternative harvesting opportunities and compensation arrangements: "There are expected to be some adverse impacts on domestic resource use and commercial trapping due to disturbance to fish and wildlife resources and habitat. However, they would be limited and offset by the provision of alternative harvesting opportunities and compensation arrangements. Licensed trapline holders would be eligible for compensation."

QUESTION:

Has there been an assessment of the estimated social cost attributed to the reduced ability to trap, fish and hunt on land that is familiar and culturally significant? If so, please provide.

RESPONSE:

The discussion of adverse effects is more appropriately canvassed in the CEC proceeding.

In their decision to become project partners, KCN community members weighed the potential adverse effects against the potential benefits; in this process, comprehensive adverse effects agreements were negotiated that addressed community concerns and priorities, including programming that affords meaningful opportunities for KCN members to pursue traditional activities such as hunting and fishing as well as enhance cultural traditions and identity. The Keeyask environmental impact statement explains the process by which the KCNs planned their offsetting programs through which they will undertake traditional harvesting activities in areas unaffected by the Keeyask Project. As part of this process, each KCN will have the opportunity to identify locations familiar or culturally significant to their members for hunting and fishing

(note that Tataskweyak Cree Nation has already identified offsetting lakes for its Healthy Fish Food Program).

REFERENCE: Chapter 1: Introduction; Section: 1.4.1.2; 1.4.1.3; Page No.: 14, 15

PREAMBLE: According to the filing, a significant strength of the proposed project is the consultation with the KCN partners and the application of Aboriginal Traditional Knowledge. It is well established that the KCN partners, who reside closest to the proposed development site, will directly experience many of the positive and negative impacts of the development.

QUESTION:

Please explain how Aboriginal Traditional Knowledge or direct input from the KCN partners was taken into consideration when establishing the Multiple Account Benefit Cost Analysis?

RESPONSE:

The Multiple Account Benefit-Cost Analysis framework was established based on well-established principles of benefit-cost analysis, but with the results disaggregated to highlight distributional impacts and non-monetized effects. The direct input of KCN partners and others is reflected in the environmental and social impact assessments that the analysis relied on.

REFERENCE:

QUESTION:

Was Dr. Shaffer advised of circumstances in which the views of the KCN differed from those of Manitoba Hydro's?

RESPONSE:

The information Dr. Shaffer relied on is provided and referenced in Chapter 13.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities; Section: 2.1.3.1; Page No.: 17, 6

PREAMBLE: Entrainment of fish through turbines has been proposed as a reasonable method of providing downstream passage for fish. Measures have been taken by the proponent to reduce mortality associated with injury and mortality. The turbine design is expected to result in 90% survival in fish up to 500 mm in length: "Protecting and enhancing Lake Sturgeon populations has been a high priority in the planning of that project. Keeyask is designed to avoid and minimize impacts on individual sturgeon and habitat. Measures include turbines that have high survival rates for any fish that swim downstream through the powerhouse, barriers that prevent larger fish from passing through the powerhouse, and selective transportation of fish upstream past the powerhouse, as required."

QUESTION:

Given that most adult lake sturgeon will be in the 800 to 1200mm range (considerably larger than 500 mm), please provide an evidence based estimate of the survival rate of lake sturgeon in the 800 to 1200 mm range. Please provide any peer reviewed studies relied upon for that estimate.

RESPONSE:

On September 30, 2013, Manitoba Hydro undertook to provide matrices of macro environmental and socio-economic issues comparing Keeyask, Conawapa, gas turbines and wind generation. The matrices will address the PUB's definitions of macro environmental and socio-economic as set out in PUB Order 92/13. Based on this undertaking, CAC withdrew this information request.

REFERENCE: Chapter 2: Manitoba's Preferred Development Plan Facilities.

QUESTION:

Does Manitoba Hydro agree that no experimental studies have been conducted that examine the incidents of injury and mortality for lake sturgeon passing through turbines? If Hydro does not agree, please provide electronic references to any studies identified.

RESPONSE:

On September 30, 2013 Manitoba Hydro undertook to provide matrices of macro environmental and socio-economic issues comparing Keeyask, Conawapa, gas turbines and wind generation. The matrices summarizes the various components of the PUB's definitions of macro environmental and socio-economic as defined in PUB Order 92/13. Based on this undertaking, CAC withdrew this information request.